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The World Bank

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Report No. 4336-KE

STAFF APPRAISAL REPORT

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

November 15, 1983

Energy Division
Eastern Africa Regional Office

Currency Equivalents

Currency Unit	-	Shilling
Kenya Cents 100	-	Ksh 1
US$1.0	-	Ksh 13.0

Weights and Measures

GWh	gigawatt hour	-	1,000,000 kilowatt hours
kV	kilovolt	-	1,000 volts
kVA	kilovolt ampere	-	1,000 volt amperes
kW	kilowatt	-	1,000 watts
kWh	kilowatt hours	-	1,000 watt hours
MVA	megavolt amperes	-	1,000 kilovolts
MW	megawatt	-	1,000 kilowatts
toe	ton of oil equivalent	-	10,500,000 kilocalories
ton	metric ton	-	1.1 US tons

Abbreviations and Acronyms

CIDA	Canadian International Development Agency
EAC	East African Community
EEC	European Economic Community
EP	Ewbank, Preece & Partners
EPDC	Engineering and Power Development Consultants Ltd.
Gibb	Sir Alexander Gibb & Partners
Government	Government of Kenya
KP&L	The Kenya Power and Lighting Company Ltd (formerly EAP&L)
KPC	Kenya Power Company Ltd.
KVA	Kerio Valley Development Authority
LBDA	Lake Basin Development Authority
MERD	Ministry of Energy and Regional Development
M&M	Merz and McLellan
SIDA	Swedish International Development Authority
TARDA	The Tana and Athi River Development Authority
TRDC	Tana River Development Company, Ltd.
UEB	The Uganda Electricity Board
WLPU	Watermeyer, Legge, Piesold & Uhlmann

Fiscal Years

Government and TARDA	-	July 1 - June 30
KP&L, KPC and TRDC	-	January 1 - December 31

KENYA

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This report is based on the findings of an appraisal mission to Kenya by I. Tuncay (mission leader), E. Bundi, R. Mitchell and J. Shaukat (World Bank), J. Gillings and L. Wolofsky (consultants). The report was prepared by I. Tuncay, E. Bundi, R. Mitchell, J. Gillings and C.H.A. Killoran.

LIST OF ANNEXES

I. ENERGY SECTOR BACKGROUND

A. Indigenous Energy Resources

1.01 Firewood, including charcoal, is by far the most important indigenous energy source of Kenya and supplies about 71% of total energy demand. However, Kenya is more industrialized than any of its neighbours, as shown by the following estimates of their dependence on traditional fuels: Burundi 81%, Tanzania 93%, Rwanda 96%, Somalia 90% and Ethiopia 93%. Kenya's forests cover about 4% of the country's total area, and are concentrated mostly in the central part of the country where average annual rainfall exceeds 850 mm. The accessible reserves of wood have been seriously depleted, and deforestation is a serious problem in some areas although there has been some replacement with extensive plantations of exotic trees. Kenya's wood resources are used not only for firewood, but also for sawn timber, plywood, and pulp and paper, of which small quantities are exported to neighbouring countries. The Bank has supported establishment of forest plantations in the past with two projects and a third project was approved in February 1982 1/; the new project also envisages strengthening the Rural Afforestation Extension Service, a government organization which currently operates 125 nurseries throughout the country. Other forestry projects, now underway, are being financed by Sweden, Denmark, Finland, Belgium and the European Economic Community (EEC), and it is hoped that these projects will provide the needed fuel for the rural population before the deforestation becomes widespread.

1.02 The hydroelectric power potential of the country is estimated to be about 6,000 MW (about 30,000 GWh per year). However, half of this is located on small rivers, and because of topographical conditions and the small scale, most is uneconomical to develop. The large hydro potential is concentrated on the Tana, Turkwel and Eweso Nyiro Rivers. The Tana River has a hydro potential of about 3,000 MW but, of this, only about 820 MW could be developed, which would produce about 4,000 GWh per year or about 1 million tons of oil equivalent. Four hydroelectric power stations - Masinga (40 MW), Kamburu (91 MW), Gitaru (145 MW) and Kindaruma (44 MW), operating in cascade some 100 miles northeast of Nairobi have developed 320 MW and an additional 140 MW would be developed under the proposed Kiambere project. The remaining 360 MW would be available for future development 2/. The only other significant hydro power potential is on the Turkwel River in north-western Kenya, where a multi-purpose project could provide about 120 MW to the system 3/.

1/ The total project costs are estimated to be about US$74 million, of which US$21.5 million will be financed by IBRD (LN 2098) and US$16 million by IDA (CR 1213). Remaining costs will be financed by the Governments of Switzerland and Italy.

2/ Major hydro potential sites on the Tana River to be developed after Kiambere: Grand Falls Tana (180 MW), Adamson's Tana (60 MW), Kotech (80 MW) and Karura (40 MW).

3/ Hydro potential on other rivers: Eweso Nyiro (100 MW), Sondu (60 MW), Webuye (20 MW), Nyando (35 MW), Arror (15 MW), Athi (60 MW).

1.03 Another source of energy is geothermal, with potential in the Rift Valley at primarily Olkaria, Eburru and Lake Bogaria. Exploration and development of geothermal potential at Olkaria field (estimated conservatively at 170 MW and optimistically at 1,000 MW) is continuing. In a project financed by LN 1799-KE in 1980, one 15 MW generating unit was placed in service in August 1981, and a second 15 MW unit in December 1982. The Bank has also provided part of the funds for a third 15 MW unit to be operational in 1985, and a loan for this project has been approved (Loan 2237-KE, February 8, 1983). Exploration is in progress in the other two areas, Eburru (financed by Japan International Corporation Agency) and Lake Bogoria (financed by the UNDP), and the preliminary evaluation of prospects by the Ministry of Energy is encouraging. The Bank is also giving consideration to the funding of a country-wide geothermal exploration program.

1.04 Solar radiation is quite high, and could provide an attractive alternative to a portion of the high cost imported energy. However, its use for water heating and crop drying provides only a small fraction of the total requirements of the country, and the Ministry of Energy is actively providing information and encouraging its greater use. In addition, the Ministry of Energy is evaluating the possibility of using more wind-driven pumps for irrigation to replace diesel-driven pumps presently in use. Kenya has constructed two ethanol plants based on the use of molasses, and the high capital and operating cost of these first two plants precludes the possibility of proceeding with another plant at this time.

1.05 Surveys have shown no significant coal deposits in Kenya and the results of past oil exploration have been disappointing. In January 1982 Bank lending for the Petroleum Exploration Promotion Project (LN 2065-KE, for US$5.3 million) became effective, and the Government is hopeful of success in this new project.

1.06 The Government cooperated with the Bank on energy sector work during 1981, which resulted in the Bank's Report No. 3800-KE entitled "Kenya: Issues and Options in the Energy Sector" (May, 1982). This contains the findings of a mission to Kenya, and a number of recommendations to improve Kenya's energy sector. (paras. 1.13-1.14).

Imported Energy

1.07 The main source of commercial energy in Kenya is imported oil and petroleum products, with small amounts of coal and electricity forming a secondary source. Over the period 1973-1981, the consumption of imported liquid fuels as a percentage of total commercial energy consumption excluding fuelwood and charcoal has reduced from about 90% to about 80%. This reduction is due mainly to the government objective of the greater use of indigenous energy resources such as hydro. Except for minor amounts of specialty oils and lubricants, most petroleum products have been processed domestically from imported crude at a refinery in Mombasa. Prior to 1973, the refinery exported about 55% of its output to the East African Community (EAC) and other African countries, but partly as a result of the break up of the EAC, there has been a fairly steady decline in exports. Net oil imports absorbed about 8% of gross export earnings in 1976-77 and reached 25% in 1981, in part as a result of the reduced earnings from coffee and tea. Kenya also imports electric energy from Uganda (about 12% of total electricity sales in 1982). The present political climate in East Africa is improving the possibility of the utilization of benefits derived from the interconnection of the national electric grids in Kenya, Tanzania and Uganda.

1.08 The major user of imported coal is the Bamburi cement plant in Mombasa. The following table contains a summary of the growth in commercial energy consumption in Kenya (fuelwood and charcoal excluded):

Commercial Energy Consumption

	Tons of Oil Equivalent (Thousands)					
	1973	%	1978	%	1981	%
Imported Energy						
Coal and Coke imports	50	3	35	2	91	4
Oil Consumption	1,360	86	1,660	83	1,672	78
Electricity a/	76	5	52	3	47	2
Domestically Produced Energy						
Hydro Power	97	6	257	12	331	15
Thermal Power (geothermal and captive plants)	-	-	-	-	20	1
Total Commercial Energy	1,583	100	2,004	100	2,161	100
Per Capita Consumption	0.130		0.135		0.132	

a/ Imported from Uganda.

Source: Economic Survey, 1982, Government of Kenya

1981 Energy Balance

1.09 In 1981, Kenya consumed approximately 7.3 million tons of oil equivalent (toe) of energy. Per capita energy consumption is about 453 kg of oil equivalent, which compares with the average of 1,500 kg for Europe, and an average of 300 kg for all of Africa. Non-commercial, traditional energy sources met about 71% of the total 1981 demand for energy, with the commercial energy providing the balance. Kenya's energy balance for 1981 is given on the following page.

Total Energy Consumption in 1981

	toe (thousand) c/	%
Local		
Firewood	4,009	55
Charcoal	1,142	16
Electricity a/	351	5
Subtotal	5,502	76
Imported		
Coal and Coke	91	1
Petroleum b/	1,672	23
Electricity	47	negligible
Subtotal	1,810	24
Total Energy Consumption	7,312	100

Per Capita Energy Consumption 453 kg of oil equivalent

a/ Production from hydro and geothermal stations. Production from steam and diesel stations is included in the imported petroleum. Six sugar estates and other private plants produced power which is included in electricity (about 120 GWh p.a.).

b/ In 1981 2,611.1 thousand toe of crude oil was imported. Net exports of petroleum is about 1,084 thousand toe and stock exchange and balancing was 145.6 thousand toe.

c/ Conversions to toe are made at the following rates: toe 1.0 = 1.5 (ton coal equivalent); toe 1.0 = 4,030 kWh (on the basis of 31% efficiency).

Source: Economic Survey, 1982, Government of Kenya

Energy Prices

1.10 The price of many essential commodities, including electricity and fuel, is regulated by the Government. Usually, prices of petroleum products vary regionally and, in general, reflect the cost of transportation. While there are no duties and taxes on fuel oil and industrial diesel oil, regular gasoline and light diesel oil are heavily taxed. The relative cost of energy in Kenya is illustrated in the following table:

Prices in Nairobi (mid 1982)

		Wholesale (including tax)	Tax	Price per million Kcal (including tax)
		---------------------KSh---------------------		
LPG	(tonne)	6,274	-	597
Premium motor gasoline	"	9,793	4,376	933
Regular motor gasoline	"	9,409	4,202	896
Illuminating kerosene	"	4,625	382	441
Power kerosene	"	6,226	287	593
Light diesel oil	"	5,907	1,648	563
Industrial diesel oil	"	3,956	-	376
Fuel oil	"	2,460	-	234
Firewood	"	150	-	50
Charcoal	"	1,400	-	202
Electricity (average)	kWh	0.63	0.01	732

Source: Economic Survey, 1982, Government of Kenya

1.11 The low selling price of diesel oil in the above price structure relative to gasoline, is encouraging an increased demand for diesel oil for the transportation sector and will create further problems in matching the yield of the Mombasa refinery to market demand. With the existing refinery yield pattern, the proportion of diesel to total production is significantly less than the proportion of market demand for diesel to total demand for petroleum products. It is the opinion of the mission that this situation would improve if the refinery were to be modified to increase the yield of middle distillates from refined crude oil, and the Bank is now considering an engineering loan to study the various options for the conversion of the refinery to improve the yield of products most in demand. Under the Second Structural Adjustment Operation (Loan 2190-KE/Credit 1276-KE; Report P-3322-KE) the Government has undertaken, inter alia, to develop a comprehensive energy investment program providing for both production and conservation in the modern and traditional sector. A draft report covering the results of the studies of the proposed investment program has been reviewed by the Bank, and the comments have been sent to the Government.

Bank Strategy in the Energy Sector

1.12 Bank strategy has continued to be focused on improving the overall energy sector. For example, the Bank has assisted in meeting the projected shortage of energy in rural Kenya through a forestry project which was approved in February 1982, with total project costs of US$74 million to which IBRD will provide US$221.5 million (LN 2098) and IDA US$16 million (CR 1213). The project is aimed at improving the forestry department's management performance and providing funds for new plantings and rural reforestation. On January 9, 1982, LN 2065 (US$4.0 million) the petroleum exploration project (total cost US$5.3 million) became effective, and although the search for domestic oil has been unsuccessful in the past, the Government is hopeful of success in this new project. All aspects of the overall energy sector are being reviewed under the structural adjustment loan (P 3322-KE, para 1.11). There is now a firm commitment from the Government to reduce energy costs including the diversion of long distance traffic from highways to the railways. However, the railways need extensive rehabilitation, and the Bank is assisting in financing part of the railways' investment plan for the period 1981-1983. The first project in which the Bank became involved in Kenya was in 1975 when the Bank provided part of the funds, US$20 million, under LN 1133-KE for the construction of a 14-inch 452 km oil pipeline, pumping stations, and related facilities to transport refined products from Mombasa to Nairobi. Since it was placed in operation in 1978, the cost of transporting fuel to Uganda, Nairobi, and other neighboring countries has been substantially reduced. Recently, preliminary studies have been carried out to determine the justification of extending the pipeline westwards to serve Eldoret and the neighboring countries, but no action has been taken to date. The East Africa Development Bank and the Kenya Pipeline Company are presently seeking funds for a detailed feasibility study of the proposed extension.

Government Strategy in the Energy Sector

1.13 The Government realizes that Kenya's economy is vulnerable to sudden increases in petroleum prices as long as expensive oil remains the major source of commercial energy, and substantial amounts of foreign exchange are expended in paying for crude oil imports. Thus, the Government's strategy, as defined in the Fourth Development Plan 1979-83, is to rationalize the use of imported petroleum, and to develop and utilize domestic power resources as far as possible to reduce dependence on imported oil. Moreover, the Government has recognized the need to formulate a comprehensive national energy development plan since the 1973-74 and the 1978 energy crises; and for that purpose established the Ministry of Energy in December 1979.

1.14 The Government is concerned about its access to petroleum supplies and the prices it is paying for petroleum. In the past, the country has had no direct contractual arrangement with any exporting country and was wholly dependent upon a few multinational corporations for its supplies. The Government has now established the Kenya National Petroleum Corporation (not yet in operation) to handle about 50% of Kenya's oil needs, leaving the balance to the private companies. In addition, high priority is given by the Government to the acceleration of the Petroleum Exploration Promotion Project (para. 1.05) which aims at helping the Government to attract experienced oil companies to carry out exploration programs under conditions equitable to both parties and to ensure that the programs and their implementation meet the highest industry standards.

II. POWER SECTOR BACKGROUND

General

2.01 The availability of power to consumers in Kenya is, in general, limited to the more densely populated narrow strip running across the southern part of the country from Mombasa through Nairobi to Lake Victoria (Map IBRD 17029) in parallel with the railway, and along the coast. The northern and eastern parts of the country are arid, and because of the scattered population, consumers do not have easy access to electricity. Of the estimated 15 million inhabitants to Kenya, 90% live in rural areas. Only 6% of the total population has access to electricity, and the average estimated per capita consumption of electrical energy was about 134 kWh in 1981.4/ This is a higher level than in most other East African countries, i.e. Tanzania 52 kWh, Mauritius 607 kWh, Madagascar 45 kWh, Ethiopia 24 kWh, Botswana 486 kWh, Malawi 64 kWh, Rwanda 11 kWh, Burundi 12 kWh, and Zimbabwe 928 kWh.

2.02 The electricity supply industry is presently composed of four entities: the Kenya Power and Lighting Company Limited (KP&L), the Kenya Power Company Limited (KPC), the Tana River Development Company Limited (TRDC), and the Tana and Athi Rivers Development Authority (TARDA). At present, KP&L coordinates all sources of power, purchases in bulk from the other three companies, and is the sole distributor. KP&L also operates all generating facilities, staffs and manages KPC and TRDC, and since August 1981, staffs the Masinga hydroelectric generating station owned by TARDA.

2.03 KP&L (formerly East Africa Power and Lighting Company Limited - EAP&L) began as a private company in 1922, and in 1970 the Government acquired a controlling interest when it made a successful bid for all the shares on the London Register. Since then the Government has been purchasing shares as they come on the East African market and, at present, holds about 57% of total shares. KPC and TRDC were originally established by the Government for specific functions. KPC's main function is to import power from Uganda, and it now owns the Olkaria geothermal power generating plant. TRDC owns Kindaruma, Kamburu and Gitaru plants on the Tana River. KP&L, KPC and TRDC form the country's main power producers, but some electric energy, about 411 GWh in 1981 (about 20% of total consumption) is generated by private organizations and parastatals which have power plants in sugar, tea and coffee estates, the oil refinery, textile factories and large farms. The power plants operate under license from the Ministry of Energy and Regional Development. During negotiations for the Olkaria Geothermal Power Expansion LN 2273-KE the Government informed the Bank that a review of the structure of the power industry was being carried out by a Government Committee which includes the issue of merger of the power companies, and the recommendations would be sent to the Bank for comment. Background information and the description of the four companies is given in paragraphs 6.01-6.04 and in Annex 17.

2.04 TARDA along with the Kerio Valley Development Authority (KVA) and the Lake Basin Development Authority (LBDA) were organized primarily to develop the river basins and have an extensive interest in irrigation, reforestation and industry. They are also empowered to construct hydroelectric power facilities, and to generate and sell their energy in their respective areas. As a result of the number of different organizations interested in developing power facilities, there is a costly duplication and diversification in power sector planning, a situation which Kenya, with

4/ Total electrical energy consumption for the country in 1981 was about 2,004 GWh of which 411 GWh was provided by private industries, while 1,593 GWh represented sales by KP&L (Annex 7).

its constraints in skilled manpower and finance, can ill afford and which has considerably delayed preparation of the proposed project. The Government has recognized the existence of the problem and agreed in Loan 2237-KE to a program for the merging of KPC and TRDC. The Government intends to carry out a separate sector organization study based on terms of reference approved by the Bank.

Existing Power Facilities

2.05 The total installed capacity of the interconnected power system is 541 MW of which 348 MW is hydro with 30 MW of geothermal, and 163 MW is oil-based thermal. The Uganda Electricity Board (UEB) also provides 30 MW. KP&L has about 9,970 km of transmission lines operating at various voltages throughout the country. Total distribution transformer capacity in service is about 1,780 MVA (excluding generating switching stations). The total system loss is about 15%, which although higher than desirable, the maintenance is adequate and this level of loss is considered reasonable bearing in mind the age and condition of the equipment. As these losses increase, KP&L installs suitable system compensation equipment, and strengthens power distribution lines within its general development program to further reduce losses as far as economically possible.

2.06 Detailed information regarding the existing power facilities is given in Annex 1 and 2 and shown on the map IBRD 17029.

Long-term Development Plan

2.07 During the preparation of the Gitaru Loan (1147-KE), it was foreseen that generation of geothermal power at Olkaria was becoming attractive, and to place it in a long-term perspective funds were included for two separate studies. As a result, Merz & McLellan (M&M) of the United Kingdom and the Virkir Consulting Group Limited of Iceland submitted a report in which it was concluded that development of the Olkaria site was economically justifiable and would be part of the least cost program for meeting the growing power demand. The results of this study were incorporated into M&M's and Sir Alexander Gibb's (Gibb) National Power Development Plan, 1978-2000, completed in 1978.

2.08 The National Power Development Plan contains a forecast of growth in demand which necessitates further development of power supplies by 1984. Funds for a feasibility study to determine whether a hydro, geothermal, or other conventional thermal projects should be undertaken were included as part of the Olkaria Geothermal Power Project (LN 1799-KE in 1980, para. 2.19). The study recommended construction of the Kiambere hydroelectric project to be completed in 1985. However, this project has been delayed while new engineering studies were completed. The Olkaria Geothermal Power Expansion Project was proposed as a result of the delay and LN 2273-KE was approved on February 8, 1983.

2.09 Kenya's future electric energy needs will be met by further development of geothermal and hydro resources, or by thermal stations using imported coal. While there has been an increase in the use of bagasse as a source of energy in other countries, there has been little development of its use in Kenya either for direct production of steam, or for the generation of electricity. In the long term, some of Kenya's electrical energy may be provided from neighboring countries. A recent updating of the long range plan prepared by KP&L resulted in the following plant program for the years 1983-1990:

		KSh	US$ a/	%
		------millions------		
1.	Olkaria 3rd unit 15 MW, 1985	466	37.3	3.3
2.	Proposed project - Kiambere hydro, 1988	4,625	353.8	30.9
3.	Turkwel hydro, 1990	3,969	317.5	27.8
4.	Geothermal (2x15 MW) b/	1,795	143.6	12.6
5.	Transmission	1,526	122.1	10.6
6.	Rural electrification	80	6.4	0.6
7.	Other c/	2,026	162.1	14.2
	Total	14,487	1,142.8	100.0

a/ Including interest during construction.
b/ Olkaria units No. 4 and 5 include drilling for development.
c/ Including normal distribution development, some office buildings and a substation.

Rural Electrification

2.11 A Rural Electrification Fund was established by the Government in 1973 with a contribution of KSh 9,980,260, and a Swedish bridging grant of KSh 8,760,640. It is administered by the Electricity Development Committee, which is comprised of representatives of the Ministries of Finance and Planning, Energy and Regional Development(MERD), and KP&L. Rural electrification schemes are managed and operated by KP&L, which receives revenue from the consumers and presents statements of revenue and cost to the committee. Funds provided from the interest differential between the soft terms of a Swedish International Development Authority (SIDA) credit to the Government for the Kamburu project and the Government's harder onlending terms to TRDC, are used to finance the rural electrification program. Annual accrual to the fund is KSh 4,431,920 from the SIDA Credit, and the interest in the investment of the Rural Electrification Fund of KSh 4 million and the Sugar Finance Corporation of KSh 250,682. Total disbursement of the fund was KSh 70.6 million at the end of 1981. A Swedish team, comprising a planning engineer and two construction foremen, were seconded to KP&L to assist in the implementation of the program.

2.12 In February 1980, the Canadian International Development Agency (CIDA) made a grant of C$550,000 (US$460,000), and in June 1981, CIDA made another direct grant of C$2.75 million (US$2.3 million) to the rural electrification program. The grant provides two technical staff members, one attached to KP&L to assist in carrying out the extension of the distribution system in the rural areas, and the other attached to MERD to assist in the socio-economic analysis of projects intended to be included in the program. In addition, of the funds from the interest differential between the soft terms of a CIDA loan to the Government, and the harder onlending terms to KP&L for the Mombasa-Kamburu transmission line amounting to about US$7 million in 1983 and 1984, about US$4 million will be spent on rural electrification, and the remainder on other unspecified energy related projects in Kenya.

2.13 In a separate rural electrification program, KP&L spent about US$800,000 per annum on 22 schemes during the 1970-76 period. KP&L normally apportions 1% of its gross sales revenue (about US$900,000 in 1981) to develop additional schemes, but in recent years the funds serve mainly to cover the losses of the earlier schemes. The major problem encountered with rural electrification programs in Kenya is the consumers' inability to pay. Demand is low because the cost limits most rural households to the use of electricity for lighting and not for other domestic or productive purposes. KP&L has only a small construction staff for this type of work. The training of construction workers was included in the training component of the Olkaria Geothermal Power Project (LN 1799-KE 1980), and it is anticipated that the additional trained staff would alleviate this problem to some extent. The geography of the country adds to the problem in that there are few village concentrations, and the scattered households make the distribution costly.

2.14 Although the rural electrification programs do not appear to be financially self-sustaining, the Government has continued to encourage the expansion of the programs by providing funds through the interest differentials (paras. 2.11 and 2.12), in the belief that improvement of the social, commercial and industrial activities in small communities will tend to reduce migration to the larger urban centers. The Government recognizes that these rural schemes are subsidized to some extent by the urban consumers, and has allowed KP&L to adjust its tariffs to enable this cross-subsidization to take place, while encouraging the least unprofitable schemes to be chosen. Although none of the schemes undertaken to date are financially viable, they do not represent an undue burden on the sector and most could become remunerative in time. Meanwhile, the social and economic well-being of the rural community is gradually being improved.

Previous Bank Lending in the Power Sector

2.15 The proposed loan would be the sixth bank lending operation for power in Kenya. Two previous loans - US$23 million for the Kamburu Hydroelectric Project (LN 745-KE of 1971) and US$63 million for the Gitaru Hydroelectric Project (LN 1147-KE of 1975) - were made to TRDC, and three to KPC - US$9 million for the Olkaria Geothermal Engineering Project (LN S-12-KE of 1978), which was absorbed into a US$40 million LN 1799-KE in 1980 for the Olkaria Geothermal Power Project, and US$12 million (LN 2237-KE) for the Olkaria Geothermal Power Expansion project in 1983.

2.16 The Kamburu project was the second phase of the Seven Forks Hydroelectric development on the Tana River (the first was a hydroelectric power station at Kindaruma). The project was designed to meet the demand for power in Nairobi and the coastal areas around Mombasa, where most of the industrial and commercial activities of Kenya are concentrated. The project consisted of:

a) a rock fill dam on the Tana River;
b) an underground power station;
c) three 30 MW units; and
d) the associated transmission line facilities connecting the power station with Nairobi and the Kindaruma hydroelectric power station further downstream.

The project was completed in 1974 about five months behind schedule with a cost overrun of about 7%. The delays were not unusual for a construction program of this nature, and the cost overrun was unavoidable as it was largely due to currency fluctuations. The Project Performance Audit Report No. 1230, dated July 14, 1976, based on the Project Completion Report, stated that the construction of the dam, powerhouse and transmission lines posed no unusual problems, and that the project was completed as planned with only minor start-up problems. It was noted that KP&L would have to rely on the technical expertise of expatriates for some years to come, and that an appropriate training program was available for all levels of personnel. The sales and maximum demand forecasts were exceeded to such an extent that with a tariff increase in 1974, the rate of return for the project was 21% as compared with the appraisal estimate of 16%.

2.17 The Gitaru project was the last phase of the development of the hydro potential at the Seven Forks of the Tana River. It is situated between the Kamburu and Kindaruma power stations, and the three stations operate in cascade. The project consisted of:

a) a powerhouse with two 72-MW units with provision for a third similar unit;
b) a 30 meter high dam, 580 meters long;
c) a 900 meter supply tunnel and a 4,700 meter tailrace tunnel;
d) switching station;
e) a 111-km transmission line to the Juja Road substation in Nairobi; and
f) three studies: Geothermal Development at Olkaria (para. 2.07); the National Power Development Plan 1978-2000 (para. 2.08); and a Management and Accounting Consultancy Study (para. 6.06).

2.18 The Project Performance Audit Report No. 3505 dated June 24, 1981 states that the project was completed within the dates established by the contracts, due to having good control and supervision by competent consultants. It was also noted that the use of bonuses for the completion of certain tasks by key dates provided the incentive for contractors to cooperate with each other and to complete their portion of the work on schedule.

2.19 The Olkaria Geothermal Power Project consisted of:

a) a powerhouse;
b) two 15-MW steam turbines and generators, with all auxiliaries;
c) a system to bring steam from the wells to the powerhouse;
d) roads;
e) housing;

f) switchyard;
g) a transmission line to join the existing Uganda - Nairobi transmission line;
h) training component;
i) detailed studies of the geothermal field; and
j) a feasibility study of the proposed Kiambere hydroelectric project.

2.20 The first unit was placed into commercial service in August 1981, and the second in December 1982, some three months ahead of schedule. A project completion report will be prepared in FY84.

2.21 The Olkaria Geothermal Power Expansion project consisted of the construction of an extension to the existing electric generating station (para. 2.19), comprising the addition of one 15-MW turbine and generator with its associated auxiliaries and other necessary civil works. In summary, the project is as follows:

a) An extension of the existing powerhouse to house a third 15-MW unit, complete with all auxiliaries and ancillary electrical and mechanical equipment;
b) a system to bring steam from the wells now being drilled under LN 1799-KE;
c) a new cooling tower, and other works associated with the cooling water system;
d) an extension to the existing switchyard;
e) a new hard-surfaced road;
f) an augmentation of the water supply to the site and to the drilling operations;
g) additional housing for an increase in operating staff;
h) detailed studies of the geothermal potential of the site;
j) studies for future projects;
k) consulting engineering.

2.22 This unit is scheduled to be placed in service in May of 1985.

Bank Strategy in the Power Sector

2.23 The Bank's continued lending in the power sector would assist in funding Kenya's requirements for electrical power, for technical assistance, for the development of Kenyan personnel to fill middle and senior management positions now held by expatriate staff, and for studies on the justification and manner that existing resources may be developed to meet the needs of the country. Without this assistance, growth in the industrial sector would stagnate, and retard the major objective of the Fourth Five-Year Development Plan, aimed at alleviation of poverty through the creation of income-earning opportunities and the provision of social services to meet the basic needs of the population. In previous loans the Bank has included funds for continued updating of the needs for the development of new electrical generating facilities, and the Bank intends to continue this practice. The present long range planning for electric power is now out of date, and the Bank's lending strategy provides funds in LN 2237-KE for two studies: future geothermal development, and for the determination of the least cost investment program.

Government Strategy in the Power Sector

2.24 The Government continues to give high priority to the development of the power sector in view of its importance for the overall economic development of Kenya. Moreover, the need to formulate a comprehensive national energy development plan has become generally recognized by the Government since the 1973-74 energy crisis. Thus, to meet the development objectives for the energy sector as defined in the Development Plan 1979-83, investment by the Government over the Plan period in generation expansion, transmission and distribution is estimated at US$226 million, of which US$59 million has been allocated for the geothermal program. The large allocation (about 21% of total capital expenditure in the power sector over the Plan period) reflects the Government's emphasis on power development.

2.25 Via the Ministries of Finance and Planning, and Energy and Regional Development, the Government controls the electric power sector of Kenya through licensing regulations, tariff structures and levels.

III. THE PROJECT

Objectives

3.01 The main project objective is to assure a firm source of reliable electric generating capacity to meet the growth in demand which is expected to exceed the capabilities of the generating facilities existing in 1987. The project would develop indigenous renewable energy resources and create new job opportunities particularly during its construction period. A further objective would be to reduce the country's heavy dependence on imported oil.

Project Description (Annex 3)

3.02 The project consists of the construction of hydroelectric generating facilities on the Tana River essentially as follows:

(a) a rock and earthfill dam approximately 100 meters high with a crest length of about one kilometer, and a saddle dam with a concrete-lined spillway, which would provide a reservoir capacity of about 585 million m^3; and two diversion tunnels each of about 0.5 km long ;

(b) an intake; a concrete and steel-lined shaft and a tunnel 6.1 m in diameter, and about 4.1 km long, to connect the reservoir to the underground powerhouse, and a reinforced concrete surge shaft near the downstream end of the tunnel;

(c) an underground powerhouse with two 70 MW vertical Francis turbines; a tailrace tunnel of about 1.4 km long;

(d) a 220-kV switchyard;

(e) 80 km of 220-kV transmission lines, to connect the generating station to the existing grid; and

(f) consultants' services for detailed design and construction supervision; and a panel of experts to advise on civil works.

3.03 Upon completion of the project, the reservoir would be available to regulate the flow of the Tana River, and carry stored water from a high flow year to the next year. The addition of 140 MW to the system would bring the total capacity including the 30 MW bulk supply of UEB to 692 MW, i.e. a 25% increase in installed capacity. It is expected to produce 910 GWh annually during an average water year which would increase the capability of the system from 2,702 GWh to 3,602 GWh, a 33% increase in energy output. During the dry years when the flow in the river is reduced due to lack of rainfall, the expected output of the plant would be about 683 GWh annually. With the dry season capability of 2,365 GWh in 1987, this additional 683 GWh would raise the firm capability of the system to 3,048 GWh annually or an increase of 22%.

Environment

3.04 The proposed Kiambere dam and reservoir would be one of a series of power producing facilities on the Upper Tana River. These projects are (upstream to downstream):

	Distance from Masinga (km)	Location (Height) above Kenya Datum (m)
Masinga (Upper reservoir) (40 MW)	0	1,056.5
Kamburu (91.5 MW)	16	1,006.0
Gitaru (145 MW)	25	924.0
Kindaruma (44 MW)	41	780.0
Karura (proposed)	58	716.0
Kiambere (the project) (2 x 70 MW)	76	700.0
Grand Falls - Mutonga (proposed)	140	555.0
Usueni (proposed)	161	420.0
Adamson's Falls (proposed)	200	360.0
Kora Hills (proposed)	255	302.0

3.05 A comprehensive environmental study was carried out by the Government and TARDA's consultants prior to the construction of the Upper Reservoir (the only significant reservoir with about 1.5 billion m^3 capacity, providing the main regulation of Tana River system). The findings and recommendations were issued in the report entitled "Upper Reservoir Pre-Construction Environmental Study" dated August, 1976. Environmental aspects of the downstream area including the Kiambere site and the flood plain were also reviewed in this study. In a separate study, Engineering and Power Development Consultants Ltd (EPDC) reviewed the Kiambere environmental aspects and issued additional findings and recommendations in a report entitled "Kiambere Hydroelectric Development" of April 1980 covering the following aspects:

- Land acquisition
- Land utilization in proximity of the project
- Roads and other communications
- Operational requirements
- Housing
- Facilities and amenities
- Resettlement
- Requirement for downstream projects.

3.06 The review by EPDC did not disclose negative effects of sufficient magnitude to influence the construction of the proposed Kiambere Dam. However, a detailed study of the integrated development, possibly including resettlement, was not completed and TARDA has retained consultants to prepare a detailed study based on the Bank's terms of reference. This study is expected to be completed in early 1984, and will be sent to the Bank for review and comment.

3.07 There are four storage reservoirs, upstream of the Kiambere site and to date no adverse effects have been observed on the regime of the river. EPDC concluded that construction of the proposed project would have no significant impact on the environment, as there are no permanent settlements in the reservoir area. Between the dam and the powerhouse, however, about 1,000 persons live on both banks within 2 km of the river. If a decision is made to permit some or all of these people to remain, it would be necessary to provide a continuous supply of water through low level outlets of the dam. An allowance for the implementation of works to reduce the environmental impacts of the construction of the proposed facilities has been included in the cost estimates.

IV. PROJECT COSTS AND FINANCING

Cost Estimates

4.01 The total project cost is estimated to be KSh 4,075 million (US$312 million), of which 47%, amounting to KSh 1,928 million (US$148 million), is in foreign exchange. The net cost excluding duties and taxes is estimated to be KSh 3,471 million (US$266 million). The local costs include KSh 604 million (US$46 million) for duties and taxes. A summary of the cost estimate for the principal components of the project may be found on the following page.

4.02 The cost estimates were prepared by Watermeyer, Legge, Piesold and Uhlmann and Ewbank, Preece and Partners (WLPU and EP) on the basis of tender prices received May 18, 1983 and adjusted by the mission on the following page. Physical contingencies of 20% were added to the civil works contracts, in view of the uncertainty of the actual conditions which would be encountered during the course of construction and the possibility of increased quantities of excavation and fill materials. Physical contingencies of 10% were added to the equipment contracts to allow for unexpected changes in requirements. Price contingencies as tabulated on the previous page were then added to the base cost plus physical contingencies.

Summary Project Cost Estimate
(KSh 12.50 = US$ 1.0)

Project Component	Local	Foreign	Total	Local	Foreign	Total	Foreign as % of Total
	KSh million			US$ million			
a) Prelimiminary Works	187.0	18.0	205.0	14.3	1.4	15.7	9
b) Dams	482.5	335.0	817.5	36.9	25.6	62.5	41
c) Tunnels	212.5	226.8	439.3	16.3	17.4	33.7	52
d) Powerhouse and access	213.8	228.0	441.8	16.4	17.4	33.8	51
e) Mechan. & Electr. Works	189.4	312.5	501.9	14.5	23.9	38.4	62
f) Transmission Line	9.4	51.3	60.7	.7	3.9	4.6	85
g) Engineering Consultants	74.3	311.8	386.1	5.6	23.9	29.5	81
h) Panel of Experts and Project Team Leader	5.0	15.6	20.6	.4	1.2	1.6	75
i) Miscellaneous	43.1	-	43.1	3.3	-	3.3	0
Base Cost (April 3, 1983 prices)	1417.0	1499.0	2916.0	108.4	114.7	223.1	51
Contingencies							
Physical	260.1	178.5	438.6	19.9	13.7	33.6	41
Price	469.8	250.6	720.4	35.9	19.2	55.1	35
Total Project Cost	2146.9	1928.1	4075.0	164.2	147.6	311.8	53
Interest during Construction							
Bank Financed	-	357.6	357.6	-	27.3	27.3	100
Other Sources	7.5	181.9	189.4	.6	13.9	14.5	96
Front End Fee on Bank Loan	-	3.0	3.0	-	0.2	0.2	100
Total Financing Required	2154.4	2470.6	4625.0	164.8	189.0	353.8	53

NOTE: Base costs are estimated and tendered prices 45 days before May 18, 1983. Physical contingency on civil items assumed to be 20% and on equipment and consultants 10%.
Price contingencies were added to the base cost plus physical contingencies as follows:

	1983	1984	1985	1986 and thereafter
Local costs %	14.0	13.0	12.0	12.0
Foreign costs %	8.0	7.5	7.0	6.0

Local costs include identifiable duties and taxes estimated to be KSh 604 million (US$46.2 million).

Miscellaneous includes insurance, environmental study, vector-borne diseases study, compensation to farmers, survey and bush clearing, electricity, and rent of Kamburu camp.

Bank loan is assumed to be US$95 million.

Project Financing

4.03 The proposed Bank loan (US$95 million) would finance about 22% of the estimated project costs (US$312 million), about 20% of the estimated foreign component (US$148 million), and about 23% of the estimated local component (US$164 million) of the project; and in each case, exclude interest during construction (US$27.3 million). It would be used to finance:

(a) 100% of the front-end fee on the Bank loan;

(b) 100% of the repayment of the two Project Preparation Facilities;

(c) 86% of the local expenditures and 4% of the foreign expenditures for the dam contract, excluding taxes;

(d) 100% of the foreign cost and 33% of the local costs of the consultants for the design and supervision of construction beginning November 1, 1982;

(e) 100% of the interest during construction on the Bank loan; and

(f) 100% of the cost of the panel experts, and the project team leader beginning April 1, 1984.

4.04 Retroactive financing of about US$2.5 million would be used to finance part of the cost of consulting engineering services from November 1, 1982. The financing of the remaining foreign cost of the dam construction would be by the African Development Bank (AfDB) (54%), the Saudi Fund for Development (28%), and the Yugoslav Bank for International Economic Cooperation (14%). The Yugoslav Bank would also finance the remainder of the local costs on the dam contract. Financing of the underground works, i.e., the tunnels and the powerhouse, and the mechanical and electrical equipment for the project would be through grants and loans from various donor agencies, TARDA, and the Government. Tenders and offers of financing for these items have been received by the Borrower, but announcement of the tender awards and the donors will not be made until discussions have been held with the various lending agencies concerned. It is expected that these would be announced after Board presentation.

4.05 A Government contribution in the form of equity in the amount of KSh 603.8 million (US$46.2 million) would be used to defray the cost of duties and taxes imposed on the project.

4.06 TARDA, would provide the remaining funds estimated at KSh 628.5 million (US$48.1 million) equivalent to about 16% of the total cost of the project including duties and taxes to cover the remaining unfunded components of the project. These funds would be provided through a development surcharge from KP&L (para. 5.11).

4.07 The total external financing would be about US$259.5 million, about 84% of the estimated cost including interest during construction and not including duties and taxes. The Bank loan to TARDA would be for 20 years including a 5-year grace period at the standard variable interest rate. A front-end fee of 0.25% of the loan amount would be due on or before the effective date and would be added to the loan amount. A condition of effectiveness would be the receipt of evidence satisfactory to the Bank that the effectiveness conditions of the other external sources have been met. A summary of the financing plan (Annex 4) follows:

Financing Plan - Summary

	------KSh millions-------			-----US$ millions----- (US$1 = KSh 13.0)		
	Local	Foreign	Total	Local	Foreign	Total
Proposed IBRD Loan	518.3	723.5	1241.8	39.6	55.4	95.0
African Dev. Bank	-	283.7	283.7	-	21.7	21.7
Saudi Fund	-	150.9	150.9	-	11.5	11.5
Other Colenders	403.8	1312.5	1716.3	30.9	100.4	131.3
Government Funds	603.8	-	603.8	46.2	-	46.2
TARDA	628.5	-	628.5	48.1	-	48.1
	2,154.4	2,470.6	4,625.0	164.8	189.0	353.8

Engineering Consultants' Services and Project Implementation

4.08 Although KP&L and TARDA have remarkably good records regarding the preparation and implementation of large hydroelectric projects, the Bank requested TARDA to employ independent cost and design review consultants to check for completeness and accuracy, the costs and appropriateness of the original design prepared by TARDA's consultants, WLPU and EP (para 4.02). This is the Bank's customary practice for large projects in the power sector. Two separate advances, one for US$250,000 (PPF No. 60) and a second for US$750,000 (PPF No. 68), were provided through a project preparation facility to carry out the above cost and design review by independent consultants on the basis of terms of reference acceptable to the Bank.

4.09 TARDA would be responsible for project implementation, assisted by civil engineering consultants, WLPU, and plant consultants, EP, who prepared the bid documents, and by a financial manager, presently being funded by the EEC. It is estimated that of the total of about 10,000 man-months which would be required by the consultants, approximately 2,400 man-months would be spent in England, 2,400 man-months by expatriates in Kenya, and 5,200 man-months by local staff in Kenya. The foregoing estimates cover not only design and supervision, but also management and operation of the camp facilities, the provision of English-speaking teachers and the staffing of a hospital with a doctor and medical support staff. The total cost of the engineering contract is estimated to be about US$39.4 million of which about US$30.6 million would be in foreign exchange. The average cost for expatriates is about US$6,400 per man-month and for local staff US$1,800 per man-month, including the cost of services, plus travel, and miscellaneous expenses. The panel of experts' man-month rate would be about US$23,300 including cost of services, travel, living and miscellaneous expenses reflecting the desired high quality of expertise to be provided to TARDA during the construction.5/ The cost of the project team leader has been estimated at US$0.7 million based on an assignment of about 60 man-months at about US$12,000 per man-month covering cost of services, travel, living and miscellaneous expenses, beginning April 1, 1984. Until then his services will be funded by the EEC. During negotiations, agreement was reached that TARDA would employ engineering consultants, the panel of experts, a project team leader, and a financial manager whose qualifications, experience, and terms and conditions of employment are satisfactory to the Bank.

4.10 The project implementation schedule (Annex 5) is based on a target in-service date for both units on May 31, 1988.

4.11 In accordance with Bank practice, the design and general concept of the dams have been reviewed by independent consultants (para. 4.08). However, during negotiations, TARDA was requested to and agreed to continue to retain a panel of experts, who would provide independent supervision of the dams, to make periodic inspections after completion, and report to TARDA and the Bank on the safety of the structures.

Procurement

4.12 Procurement for work and material financed by the Bank for the construction of the main and the saddle dam together with the two diversion tunnels, has been in accordance with Bank guidelines for international competitive bidding (ICB) from prequalified tenderers. TARDA has proceeded with ICB from prequalified contractors for all other contracts (4 for underground works, and 8 for plant). These civil works and plant contracts were based on the requirement that bids be accompanied by financing offers. Evaluation was first based on technical grounds; acceptable bids were then compared on the basis of total evaluated costs including that of the proposed financing package.

4.13 The request for submission of bids for civil works were issued to prequalified bidders on February 1, 1983 and requests for bids for equipment were issued to prequalified bidders on February 25, 1983. All bids were received on May 18, 1983. TARDA expects to award all contracts before the expiration of a revised validity period but after Bank Board presentation.

Disbursement

4.14 The proceeds of the loan would be disbursed over five years on the following basis:

(a) 100% of the reimbursement of the PPF;
(b) 100% of the front-end fee;
(c) 86% of the local cost and 4% of the foreign cost of the construction of the dams;
(d) 100% of the foreign cost and 33% of the local costs of the consultants for the design and supervision of construction beginning November 1, 1982;

5/ TARDA would like to keep the original panel for the design review of the project for the construction supervision.

(e) 100% of the interest during construction on the Bank loan; and
(f) 100% of the cost of the panel of experts, and the project team leader beginning April 1, 1984.

4.15 The remaining costs would be disbursed from funds of other lenders, TARDA, and the Government. All disbursements would be fully documented by TARDA. The closing date for the loan would be June 30, 1989 and any savings which may accrue due to lower purchase prices, or if contingency funds are not needed, would be cancelled. The disbursement schedule (Annex 6) deviates from the Bank disbursement profile for hydro projects for East Africa because funds are being provided only for the dam construction and consultants.

Accounts and Audit

4.16 KP&L, KPC and TRDC prepare their accounts in accordance with sound commercial and public utility accounting practices. These accounts are currently audited by Gill and Johnson, whose performance has been generally satisfactory and acceptable to the Bank. KP&L also prepares consolidated statements for KPC and TRDC and for all three companies. During negotiations it was agreed that the requirements of the Bank for earlier Bank loans (745-KE, 1147-KE, 1799-KE and 2237-KE) relating to submission of annual accounts of the three companies within six months of the end of the financial year certified by independent auditors acceptable to the Bank, and submission of consolidated accounts of the three companies, would be repeated for the proposed loan.

4.17 TARDA's accounting procedures were designed to meet the requirement of Government as well as commercial accounting standards and to provide necessary data relative to the construction program. The audit for the fiscal year 1981 has been completed and the accounts for FY82 will be submitted to the Auditor General shortly. However, the Auditor General, due to a considerable work load, has not expeditiously performed the audit on accounts. This has not been critical in the past as TARDA's activities have been very limited. TARDA believes that there should be no problem in the future in obtaining more timely audits from the Auditor General and that it would be able to submit its audited accounts to the Bank within six months after the close of the fiscal year. During negotiations it was agreed that TARDA would submit its accounts to the Bank, certified by an independent auditor acceptable to the Bank, within six months of the end of the fiscal year. It is anticipated that the audit of the Auditor General would be acceptable to the Bank and that no additional audit would be required. It was also agreed that TARDA would submit appropriate data by June 30 on each preceding calendar year so as to make possible the determination of the sector (excluding rural electrification) rate of return on average net revalued assets.

V. FINANCIAL ASPECTS AND COST RECOVERY

Introduction

5.01 The public power sector in Kenya exclusive of rural electrification is presently comprised of the activities of four companies - KP&L,

TRDC, KPC and TARDA. For convenience, the term, KP&L companies, is used in this report to cover the joint activities of KP&L, TRDC and KPC. These companies are closely connected through common management and staff while only the power operations of the fourth, TARDA, are carried out by the staff and management of KP&L. For the purposes of this report it is assumed that the Kerio Valley Development Authority (KVA), would be responsible for the implementation of the Turkwel Hydroelectric Project.

5.02 The financial performance and position of the KP&L companies have been consolidated (Annexes 7-10) as these companies are very closely associated and should not be evaluated in isolation. However, an evaluation of the operations of the sector (excluding rural electrification) must include the power related operation of TARDA and KVA. Accordingly, the operating income of the KP&L companies and the power related operations of TARDA and KVA have been combined (Annex 11) by eliminating all intercompany transactions. The combined operating income has been related to the combined revalued net fixed assets to develop a rate of return for the entire power sector, excluding rural electrification (para. 5.12).

5.03 TARDA began its power operations with the commissioning of the Masinga Power Station in December 1981. Operations prior to this date were limited and not power related. Details of TARDA's operations are shown in Annexes 12 to 14.

Past Financial Performance

5.04 The operations of the KP&L companies from 1979 through 1982 based on audited annual accounts are summarized below.

	1979	1980	1981	1982
Units sold (million KWh)	1409.4	1468.6	1592.5	1631.3
Average revenue per KWh (KSh)	.41	.48	.58	.63
	KSh Million			
Revenue	573.8	701.5	920.0	1020.5
Operating Expenses	339.4 a/	487.4 a/	497.8 a/	686.7
Operating Income	234.4	214.1	422.2	333.8
Less: Interest Expense	102.3	97.7	104.6	117.7
Other Income (Expense) net	(18.2)	31.8	(172.9	(167.2)
Net Income	113.9	148.2	144.7	48.9
Rate of Return Revalued Base	7.9	6.4	11.6	7.2

a/ This reflects historical cost depreciation as reflected in audited accounts; however, operating expenses have been adjusted for rate of return computation purposes to reflect depreciation on the revalued asset basis.

5.05 The consolidated rates of return for the three companies for the years 1979-1982 were 7.9%, 6.4%, 11.6% and 7.2% respectively. These results reflect an adequate earnings position which in 1981 was substantially above the 7% earnings requirement of Loan 1799-KE. The Government has approved an increase in tariffs in 1983 so as to further improve the earning position of the companies (para. 5.10).

5.06 Net income for the years 1981 and 1982 have been significantly decreased due to exchange losses resulting from currency revaluation. These currency rate fluctuations have also had adverse effects on the foreign currency debt of the three companies. In the rate of return covenant (para. 5.12) the provision for annual pro forma revaluation of assets on a price index agreed between KP&L, TARDA and the Bank, which would reflect the increases in the replacement cost of fixed assets due to currency rate fluctuation as well as inflation would be repeated.

Financial Position

5.07 Annex 8 details the three KP&L companies' consolidated financial position based on audited accounts on December 31, 1981, and 1982. These results are summarized below.

	-----KSh Million-------	
	1981	1982
Assets		
Net Plant in Operation (revalued)	3,661.1	4,172.5
Plant under Construction	655.8	903.4
	4,316.9	5,075.9
Other Assets	18.6	17.0
Current Assets	489.3	636.7
Total Assets	4,824.8	5,729.6
Equity and Liabilities		
Equity	2,729.4	2,899.2
Long-term Debt	1,850.5	2,475.4
Current Liabilities	244.9	355.0
Total Equity and Liabilities	4,824.8	5,729.6
Current Ratio	2.0	1.8
Debt Equity Ratio	40/60	46/54

5.08 The working capital positions of the three companies at June 30, 1980 and 1982 are acceptable with current ratios of 2.0 and 1.8, respectively, due primarily to good control of debtors; account receivables amounted to about two months' billing. The cash position at end 1982 was very low but is expected to improve during the project period. However, there could be a minor cash problem during the project years. KP&L has available a short term line of credit with local commercial banks to provide necessary funds if small cash shortages are experienced. A history of the loan capital structure is shown in Annex 15.

KP&L Tariffs

5.09 Based on a tariff study performed by the Bank in 1977, a tariff structure, giving consideration to long-run marginal costs (LRMC), was introduced in January 1979. A fuel oil surcharge has been added to allow KP&L to recover any increase in the cost of fuel used in power generation. The detail of the current tariff is shown in Annex 16.

5.10 The commissioning of the Masinga Hydroelectric Station in December of 1981; the strengthening of transmission interconnection between the coast, central and eastern areas of Kenya in 1983; and the planned commissioning of geothermal and hydro generating capacity in the 1980s (Kiambere and Turkwel) have changed and will substantially change the operating characteristics of the power sector in Kenya. Therefore KP&L has recently carried out a new tariff study based on LRMC and has obtained approval from Government for appropriate revision of the tariff levels, which calls for a K¢8 increase in the average revenue per kWh every year, the first increase was effective June 1, 1983 with subsequent increases every January 1. This tariff revision program was confirmed by Government during negotiations.

5.11 KP&L has in the past assisted the financing of TRDC's and KPC's construction programs by paying a development surcharge which provided local currency funds for capital expenditure. The funds for this development surcharge are obtained from the application of the tariff and are not identified to the consumer. KP&L plans to utilize this practice to provide local fund assistance to TARDA and, for the purpose of this report it is assumed, to KVA for the construction of Turkwel. TARDA, KP&L and the Bank have agreed that for Kiambere, a reasonable amount of this contribution would be at least 15% of the total cost of the project including interest during construction, duties and taxes (15.6% excluding duties and taxes). This agreement has been incorporated in the proposed lease being negotiated by KP&L and TARDA. To meet local cost requirements the financial projections reflect a contribution of KSh 628.5 million. KP&L has agreed that this level of contribution would be acceptable and is prepared to make available additional funds if necessary to meet these requirements.

5.12 The tariff revision program agreed to during negotiations (para. 5.10) would provide necessary funds during the project period and would produce rates of return for the sector on revalued asset basis of 7.2% in 1983, 7.9% in 1984, 9.2% in 1985, 9.7% in 1986, 10.4% in 1987 and 8.9% in 1988. By December 31, 1988, the KP&L companies will have a cash position of KSh 125.8 million. With the possible utilization of short-term financing during critical times in the construction period (para. 5.08), the power sector would be able to meet its financial requirements with the program which would result in rates of return of at least 8% from 1984 and 1985, 10% for 1986 and 1987 and 8% thereafter. Therefore during negotiations it was agreed that Government would take, or cause to be taken, all actions necessary to permit KP&L to obtain the necessary revenues to produce these rates of return on the combined average net fixed assets of the sector excluding rural electrification, revalued in accordance with the price index agreed to between KP&L, TARDA and the Bank, and during the construction of the Kiambere project to obtain revenues sufficient to contribute at least 15% of the total cost of the project including interest during construction, duties and taxes.

Proposed Financing Plan

5.13 A detailed funds flow statement for the KP&L companies is shown in Annex 9. A summary financial plan for 1983 through 1988 for the sector follows:

Financing Plan 1983-1988

	KP&L Companies	TARDA	KVA	Total Sector	
	KSh Millions				US$ millions	%
Requirements of Funds						
Construction						
Ongoing Works	1,252	30		1,282	98.1	12
Project	-	4,078		4,078	311.9	36
Future Works	1,941	-	2,273	4,214	322.4	37
TOTAL	3,193	4,108	2,273	9,574	732.4	85
IDC	177	547	242	966	73.9	8
Total Cost	3,370	4,655	2,515	10,540	806.3	93
Working Capital Increase	554	187	-	741	56.7	7
Total Requirements	3,924	4,842	2,515	11,281	863.0	100
Sources of Funds						
Internal Generation	4,550	1,133	503	6186	473.2	55
Less Debt Services	2,251	288		2,539	194.2	23
Dividends	140	-	-	140	10.7	1
Net Internal Generation	2,159	845	503	3,507	268.3	31
Borrowings						
Proposed Project						
IBRD Loan	-	1,242		1,242	95.0	11
Other Finances		2,151		2,151	164.5	19
Ongoing and Future Projects	1,512	-	1,557	3,069	234.8	27
Total Borrowings	1,512	3,393	1,557	6,462	494.3	57
Government Grant						
Proposed Project		604		604	46.2	6
Other	253	-	455	708	54.2	6
Total Grants	253	604	455	1,312	100.4	12
Total Sources	3,924	4,842	2,515	11,281	863.0	100

5.14 During the project period 1983-1988, the Kenya power sector construction program anticipates expenditures of KSh 10,540 million, (US$806 million) including interest during construction of KSh 966 million, (US$74 millions). About 44%, KSh 4,625 million (US$354 million) of this total construction program relates to the proposed project. Based on the financing plan outlined in para. 5.13, this program would be feasible and would not endanger the soundness of the sector.

5.15 Internal generation after covering debt service and dividends would produce 31% of the funds required during 1983/1988 period (or 33% exclusive of duties and taxes).

5.16 All of the foreign exchange expenditures and some of the local expenditures would be financed from external financial sources. This would be appropriate as many of the foreign loans carry soft terms. Exclusive of duties and taxes borrowing would provide 61% of fund requirements. The Bank's share of this financing plan, KSh 1,242 million (US$95 million), would contribute 12% of the total requirements.

5.17 Other loans and grants are expected to be made to TARDA or to the Government. The effective lending and onlending interest rates to TARDA on its other loans are expected not to exceed 10% as the terms of many of the foreign loans would be soft and it has been a Government policy to onlend foreign funds to Government entities at an interest rate slightly above that being charged Government by the foreign agency. TARDA would bear the exchange and interest risk. Under the proposed lease (para. 6.05) for use of the Kiambere hydroelectric station KP&L would pay TARDA a rental which would cover TARDA's debt service on Kiambere over a twenty year period after commissioning at an interest rate of 11.5% which is slightly below the estimated local inflation rate. However, KP&L proposes to delay the signing of this agreement until the lending and onlending terms to TARDA are finalized. During negotiations the Bank and Government agreed that the execution of the onlending agreement with TARDA and the lease agreement between TARDA and KP&L would be conditions of effectiveness.

Future Operations and Financial Performance

5.18 The projected operation of Kenya's power sector, excluding rural electrification for the years 1983/90 together with notes and assumptions used in their development, are shown in Annexes 7 through 11. The projections indicate that the sectors' financial performance and condition would be satisfactory throughout this period on the basis of the tariff levels consistent with the proposed covenant (para. 5.12). During the period, electricity sales are forecast to increase at about 6% per year while revenues, reflecting both demand and annual tariff increases would increase over 3 times. Key financial indicators during the construction period follow:

Year	1983	1984	1985	1986	1987	1988
KP&L Companies						
Current Ratio	1.5	1.6	1.7	1.7	1.8	1.8
Debt/Equity Ratio	45/55	42/58	38/62	34/66	32/68	29/71
Debt Service Coverage	1.7	2.3	1.9	2.0	2.0	2.2
TARDA						
Current Ratio	1.6	1.0	1.4	1.8	3.0	5.4
Debt/Equity Ratio	77/23	72/28	69/31	68/32	67/33	66/34
Debt Service Coverage	1.7	2.9	3.9	4.4	5.0	4.2
Sector						
Rate of Return	7.3	8.1	9.5	10.0	10.7	9.0

VI. THE BORROWER AND EXECUTING AGENCY

The Borrower and Power Supply Entities

6.01 The Tana and Athi Rivers Development Authority (TARDA) would be the borrower, and the executing agency for the proposed loan. The power companies (para. 2.02) responsible for the generation and distribution of power have competent management, are operated efficiently, and are among the best electric utility organizations in Africa. Annex 17 gives a history of the power companies and Annex 18 contains a description of each organization.

6.02 TARDA, a regional development agency, is accountable to the Ministry of Energy and Regional Development. Founded in 1974 as the Tana River Development Authority, TARDA changed its name in 1981 upon assuming the planning responsibility for the Athi River Basin. Its duties include the following:

(a) to advise the Government on all development possibilities within the Tana and Athi River basins;

(b) to establish long range plans for the effective utilization of the water resources of these basins;

(c) to coordinate and maintain all development projects in the catchment area and, in some cases, undertake the execution of development projects including power projects; and

(d) maintain liaison between the Government, the private sector and foreign agencies in development of the Tana and Athi basins.

6.03 TARDA's Board of Directors consists of a Chairman, appointed by the President, seven Permanent Secretaries from various Ministries, the General Manager of the National Irrigation Board, the Chairman of KP&L, the Director of Water Development, and five representatives from various sectors who are appointed by the Minister of Energy and Regional Development, in consultation with the President. Day-to-day management is delegated to the Managing Director, with four department managers for: (i) the Athi River Planning Team, (ii) Tana River Planning Team, (iii) Finance and Personnel and (iv) Administration. In addition, a project team leader (position vacant since August 1982) and a financial advisor, the only staff directly attached to TARDA's power activities, report to the Managing Director. In August 1982 TARDA had 110 employees, including two expatriates (a financial adviser, and a hydro resources and irrigation engineer).

6.04 Existing staff are competent to carry out the financial responsibilities of the organisation. However, TARDA requires other technical assistance, and would carry out the project with the help of engineering (all expatriates) consultants. TARDA would also employ a project team leader and two civil engineers who would be responsible for construction supervision and management activities for the project. Similar arrangements were made for the implementation of the Masinga hydroelectric project which was successfully completed in December 1981. In addition, TARDA would be assisted by KP&L who would be associated with all phases of project implementation: design, procurement, construction and site supervision on the basis of regular information by correspondence and coordinating meetings. As KP&L would be responsible for the operation of the project power facilities, a technical training program would be designed for KP&L staff and training would be provided as part of the contracts for supply of major items of equipment. TARDA has employed a part-time panel of experts to review and advise on the solution of possible construction problems. These arrangements are adequate.

6.05 At present, the only electricity facility owned by TARDA is the Masinga hydroelectric generating station, which is managed and staffed by KP&L, which (through TRDC) purchases the energy on the basis of an agreed price per unit of electricity received. These revenues received by TARDA cover its debt service related to the financing of Masinga hydroelectric station while operating and administration costs, including insurance, are borne by KP&L. KP&L and TARDA have sometimes found this arrangement inequitable and prefer to utilize a different approach and have negotiated a leasing agreement to cover the generating costs of Kiambere. During appraisal, KP&L, TARDA, and MERD agreed in principle to an alternative arrangement for operation of Kiambere power station after it is commissioned. The essential features of the arrangement would be as follows:

(a) KP&L would have the right to lease and operate the electricity-related Kiambere installations including the powerhouse, substations, etc.;

(b) KP&L would operate and manage these installations and bear all direct operating costs associated therewith;

(c) KP&L would pay the following amounts as rent for the leased facilities:

(i) TARDA's overhead expenses (a fixed charge of KSh 4 million per year, subject to periodic review); and

(ii) Debt servicing requirements for Kiambere station's electricity-related fixed assets.

6.06 The above arrangement is considered satisfactory to the Bank for the following reasons:

(a) KP&L with experience in operation of similar power stations would have full responsibility for operation of the Kiambere power station. TARDA would, therefore, not be required to duplicate similar capabilities to operate and manage power plants and would consequently be able to devote its efforts more fully to its primary functions of regional planning and development.

(b) KP&L would have the incentive to make the best possible use of the leased plant in coordinating the plant's operation with the operation of other generating facilities in the country since Kiambere plant's operational and cost considerations would be substantially similar to those of other plants.

(c) KP&L would have a relatively dependable basis for forecasting the cost of energy from the Kiambere plant and it would, therefore, be in a position to establish realistic levels for its electricity tariffs.

(d) TARDA would receive sufficient revenue from KP&L through the lease agreement to service all its loans related to the financing of Kiambere.

Insurance

6.07 The three KP&L power companies maintain sufficient coverage for the power operations against loss from fire and special perils in addition to normal coverage such as for the motor vehicle fleet, workman's compensation, personal accident, third party liability, etc. This coverage incorporates the operation of TARDA's electricity assets and the arrangement is satisfactory to the Bank.

Billing and Collection

6.08 Customers of KP&L are billed monthly on a cyclical billing basis. The major portion of this billing is computerized and performed in Nairobi. A small number of large users in Mombasa and on the Coast are billed manually in Mombasa as this approach results in more rapid collection of these revenues. A strict "disconnection for non-payment" practice is maintained for all non-government accounts. The value of accounts receivable have been maintained at a 65-day revenue level which is acceptable particularly when the effect of the slower payment of Government accounts due to normal, more intricate Government payment practices is considered.

Training

6.09 KP&L has several training programs designed to produce qualified staff to meet the company's normal growth and to compensate for the frequent loss of employees to other sectors of the economy because of salary differentials. The cost of training in 1982 was KSh 23 million for 352 trainees. Of these, there were 31 students at university and 2 graduate apprentices primarily in mechanical and electrical engineering. Presently there are 177 trainees in the Technicians Training Program, sponsored by KP&L at the polytechnic schools in Nairobi and Mombasa. This number will be increased by at least 50 as a result of January 1983 recruitments. One hundred and twenty seven candidates who did not meet the requirements for training as technicians were apprenticed as linesmen, mechnical and electrical fitters, welders, etc. Ten of the middle and senior managers attended management courses conducted abroad, and 20 more attended courses by the Kenya Institute of Administration and the East African Management Institute. Other training requirements were covered in a previous Bank project (LN 1799-KE). KP&L's training arrangements are satisfactory.

Staff

6.10 TARDA's staff directly attached to its power operation include a hydro resources and irrigation engineer and a financial adviser (both expatriates). However, since KP&L would be associated with all phases of project implementation and would be responsible for operating the project facilities, it is more appropriate to examine the staffing position in KP&L.

6.11 The staff of KP&L at November 30, 1982, inclusive of staff attached to KPC and TRDC, numbered 5300, an increase of about 6% over the past year. The increase in staff was employed mainly in the line maintenance to improve the distribution network. There has been a significant reduction in expatriate staff as evidenced by the fact that in 1970 there were 189 expatriate professional staff, 120 in 1974 and 53 in 1982. The number of metered connections on November 30, 1982 was 177,702 and there were about 34 consumers per employee. This compares favorably with some of the other East African countries 6/ and is reasonable considering the number of installations (some 25 power stations spread over Kenya), the distances involved, the amount of construction work carried out by the company, and staff training needs.

6.12 Maintaining the establishment at full strength as well as avoiding a deterioration in the quality of staff are continuing problems. Departing expatriate staff have generally been replaced with qualified local staff, and there are a number of vacancies which KP&L is having

6/ Mauritius 74; Tanzania 22; and Madagascar 38.

difficulty in filling with suitable candidates, particularly in the area of finance and accounting. The post of Finance Manager has been vacant due to better paid jobs in the private industries. However, KP&L has identified a suitable local candidate to fill the position of the Finance Manager, and he commenced employment with KP&L early 1983. The standard of management of the companies has been maintained at a satisfactory level since the appraisal of the Olkaria Geothermal Power Project in 1978. KP&L will have to rely on expatriates for some years but their need is decreasing and eventually all posts will gradually be filled by properly trained Kenyans as they become available in the market or through the efforts of the training program (para. 6.09).

Project Monitoring and Evaluation

6.13 During negotiations the reports and records necessary to monitor progress of the project and its evaluation on completion were agreed. Proposed guidelines for a project monitoring system are given in Annex 19. On completion of the project KP&L will prepare a project completion report.

VII. PROJECT JUSTIFICATION AND RISKS

Demand and Market

7.01 Sales of electricity have been rapid during the last decade with an average annual growth of about 9%, with the highest growth 11.2%, achieved in 1977 at the peak of the coffee boom, and the lowest rate, 7.6% recorded in 1974 following the 1973 petroleum crisis. In recent years, the growth rate has declined to less than 8% p.a. as a result of a slowdown in economic activities.

7.02 An analysis of historical growth trends relating the growth in sales for the two major categories: (a) domestic and small commercial, and (b) industrial and large commercial, to the growth in overall gross domestic product and manufacturing sector growth rates respectively, was carried out. A high correlation, at greater than 95% confidence level, was found to exist between power sales growth and economic growth. On this basis, functional relationships were determined for the two basic groups of consumers (domestic and small commercial, and industrial and large commercial) on the assumption that the historical relationships will continue in the medium term (up to 2000). In the long run, these relationships may change as a greater percentage of the population is served and as the industrial sector matures. However, such a change may not occur until after the study period of this project (beyond year 2000).

7.03 In addition to consumption forecasts for the two basic categories discussed above, individual forecasts have been made for off-peak sales (interruptible supply for domestic water heating and irrigation pumping), street lighting, and supply to KP&L staff. The forecast of industrial sales has been adjusted to take into account specific new industrial loads resulting from projects either under construction or with a high probability of realization. The overall sales were found to have a growth rate of about 6% p.a. between 1982 to 1990 which is lower than the historical growth rate, due to expectations of lower economic growth. Energy sales and average yearly growth rate of consumer groups are as follows:

Consumer Groups	Sales (GWh) ---Actual--- 1975	1980	-Forecast-- 1985	1990	Percent Sales (average) 1975-80	Average Annual Growth Rate (%) (1980-85)	Average Annual Growth Rate (%) (1985-90)
Domestic and Small Commercial	294	402	568	816	27	6.4	7.5
Industrial and Large Commercial	562	944	1,277	1,696	61	10.9	5.8
Off-peak	134	111	120	120	11	0.9	0.0
Street Lighting	11	11	12	13	1	0.0	0.0
Total	1,001	1,468 a/	1,977	2,645	100	8.5	6.0

a/ Restricted sales due to load shedding (dry year). The adjusted sales are 1,508 GWh in 1980.

7.04 It is evident from the above table, that industry and large commercial consumers are by far the largest group, and the Bank expects that it will remain so in the foreseeable future. Details of the load forecast are given in Annex 20.

7.05 The timing for the addition of new generation capacity has been determined by KP&L and confirmed by the appraisal mission. Based on existing capacities, available cost estimates and the load forecast, the present program would be the least cost solution (Annex 19). By 1988 total system firm capacity would be about 480 MW and 2,313 GWh 7/ (excluding Kiambere) but would be insufficient to meet the expected demand of 465 MW and 2,771 GWh with minimum system reserves of 105 MW (corresponding to one of the largest hydro units and one of the largest thermal units out of service). Additional capacity (the proposed Kiambere project 140 MW, 683 GWh firm energy) would therefore be needed to meet the energy requirements in 1988.

7.06 The present power sector development plan has evolved from the National Power Development Plan (1978-2000) prepared by M&M and Gibb in 1978. This study reviewed several alternative scenarios to meet the expected load growth, beginning with the Olkaria project (para. 7.08) and taking into account the potential for development of both hydro and thermal schemes. The study recommended construction of the Kiambere project to be completed in 1985; however, project preparation was delayed while new

7/ Allowing for retirements and assuming that Uganda cannot guarantee firm supply of 30 MW and 250 GWh.

engineering studies were undertaken. WLPU and EP, TARDA's consultants, revised the load forecast and completed the new studies and indicated that although the Kiambere project is the least cost next generation addition, it could not be completed before 1988. On that basis, it was found that a small deficit in meeting the demand would occur in 1985 before the completion of Kiambere (para. 2.08) and the construction of the third 15-MW Olkaria geothermal unit was planned for completion in 1985 (para. 2.21 and 2.22).

7.07 Further deficits of about 10 MW and 30 MW may occur in 1986 and 1987 respectively based on the current demand forecast. Construction of additional geothermal units at Olkaria cannot be considered as an alternative to meet these deficits as the availability of steam has not been proven; therefore, KP&L planned the construction of a 30-MW gas turbine driven unit in 1985 at Mombasa. The availability of this gas turbine unit would also permit the operation of the Masinga reservoir and the Tana cascade hydro plants in a mode which would maximize average annual energy, thereby reducing thermal generation at the existing Kipevu thermal plant. Mombasa is the second largest load center after Nairobi and the proposed gas turbine would increase system supply reliability in the Mombasa area. However, in view of the constraints imposed by the lack of funds, and to reduce the need for further tariff increases, KP&L has decided to defer the construction of the gas-turbine plant, and accept load-shedding, if demand exceeds supply during peak demand periods.

Need for the Project

7.08. TARDA's consultants (WLPU and EP) have demonstrated that Kenya needs additional generation capacity in 1988 (Annex 20) to meet the power and firm energy requirements for Kenya's expected load growth and this has been verified by the Bank's consulting economist. The Kiambere output would have an annual average generation of 910 GWh. Without the Kiambere project's two 70 MW hydroelectric units it is expected that during a dry year, when power from Uganda is not available, there could be a 90 MW deficit in capacity and a 458 GWh energy deficit in 1988.

Least Cost Power Generation Solution

7.09 Additional generation facilities should be added to Kenya's existing system when either maximum demand exceeds firm system capacity or firm energy capability (para. 7.06). Beginning in 1988, the system requires additional firm energy before firm capacity. The technically feasible new plant alternatives are:

(a) gas turbine or diesel units;
(b) Kiambere hydroelectric project;
(c) geothermal units;
(d) imported oil or coal fired steam units; and
(e) other hydropower plants.

7.10 Another possibility is the importation of power from either Tanzania or Uganda, since large amounts of relatively low cost hydro energy could be developed in those countries. However, it is unlikely that Uganda would be able to increase its committed supply level to Kenya beyond the present level of 250 GWh/yr (the existing 30 MW contract runs through 2005) before 1990. Increasing load growth in Uganda could also prevent UEB from guaranteeing a firm supply in the absence of any addition to Uganda's generating capability. Since there are no firm commitments for such additions, it has been assumed that the 30 MW capacity from Uganda would not be available at the time of the yearly peak after 1988 since both system peaks occur during the same season. Furthermore, in keeping with Government objectives to ensure national independence in energy supply, the assumption that the 250 GWh/year energy supply from the Uganda Electricity Board (UEB) would not be a firm source after 1987 has been used by the appraisal mission in deriving the energy balance. Even if UEB energy supply were available, a firm energy deficit of 76 GWh would occur in 1988. It is nevertheless expected that the 250 GWh/year supply would continue to be available to the end of the existing contract, (2005) and would be used to augment the Tana system reservoirs, and displace thermal generation. There is a good possibility that after the Kiambere and Turkwel capacity have been fully utilized, imported power from either Uganda or Tanzania could be the least cost solution to meet load growth when compared to additional thermal generation.

7.11 Although a number of potential sites for hydroelectric generation have been identified in Kenya including sites on the Tana, Athi, Turkwel and other rivers, none of these sites could be considered as a possible alternative to the Kiambere project, because none have been studied in sufficient detail so that they could be developed for operation by 1988 8/. Furthermore, the 1978 power sector development plan identified Kiambere as the cheapest site for next development. Gas turbines, diesel units, oil- and coal-steam units based on imported fuel are by far the most expensive alternatives compared to Kiambere. However, additional gas turbines and diesel units were considered to firm up hydro energy in dry years or to defer the addition of new hydro plants with large investment costs in the event of a capacity constraint only. Therefore possible programs to satisfy the load growth to 1995 have been determined from the options below:

Project	Installed Capacity (MW)	Firm Energy (GWh)	Average Energy (GWh)	Earliest On-line Date
1. Gas turbine (thermal)	1x30	a/	a/	1985
2. Diesel station (thermal)	2x15	a/	a/	1985
3. Kiambere (hydro)	2x70	683	910	1988
4. Turkwel	2x60	430	460	1990
5. Geothermal (thermal)	3x15	260	260	1989
6. Coal power plant	2x60	720	720	1989
7. Oil-fired power plant	2x60	780	780	1989

a/ Not for base load. Generation depends on the results of a simulation study of the need to produce back-up energy during dry years or to defer hydro projects to optimize investment program.

8/ Funds amounting to US$2.0 million have been provided in LN 2273-KE in 1983 for detailed studies of future projects so that several projects may be considered as viable alternatives.

7.12 On the basis of above generation options and simulation studies involving the analysis of many development strategies, the Kiambere project has been demonstrated (Annex 21) to be the least cost generation solution to meet the demand up to 1990/91. Additional generation would likely be a blend of hydro and geothermal generation if power interconnections with the neighboring countries is not possible.

7.13 Development alternatives with any oil-fired or coal-fired steam plants were found to be the most expensive alternatives for the tested discount rates (10 to 28%) because of very high imported fuel prices (US$180 and US$70/ton for fuel oil and coal respectively). Sensitivity studies have shown that even at US$50 per ton, the coal-fired steam plant is far more expensive than Kiambere, and postponement of Kiambere even for one year by an oil-fired plant would not be justified. Expansion of the existing Gitaru hydroelectric generating station by a third 72-MW unit was considered and was found to be one of the most expensive solutions. The following three development programs are the most meaningful among several tested to meet the demand through 1993:

Year to be Commissioned	Alternative A	Alternative B	Alternative C
1987	Kiambere (70 MW)	Gas Turbine(25MW)	
1988	Kiambere (70 MW)	Gas Turbine(2x25MW)	Gas turbine (3x25 MW)
1989		Coal Steam (120 MW)	Geothermal (45MW) Gas turbine (35MW)
1990	Turkwel (60 MW)		Kiambere (70 MW)
1991	Turkwel (60 MW)		Kiambere (70 MW)
1992	Geothermal (30 MW)	Kiambere (70 MW)	
1993	Geothermal (15 MW)	Kiambere (70 MW)	
1994			Turkwel (60 MW)

Alternative A is Kenya's current power sector development program and, therefore, has been taken as the base case for comparison. The plant additions up to 1987 (viz. the third 15 MW Olkaria geothermal unit) was omitted from the least-cost analysis since it is common to each alternative. Since Alternatives B and C would provide greater capacity and firm energy than Alternative A, an allowance in 1994 for the residual values of the extra gas turbine capacity provided by these alternatives has been made in the cash flows of the least cost analysis. A fourth option, which tested the sequence of Turkwel versus geothermal (i.e. Kiambere, geothermal, Turkwel), was also examined during appraisal and results of the analysis suggest that geothermal development before Turkwel could be more costly for all discount rates. The installation of gas turbines to firm up existing hydro generating plant and defer Kiambere by one year was found to be more costly than constructing Kiambere in 1988.

7.14 The analysis of the three development programs above has indicated that alternative A, beginning with Kiambere, would be the least cost program for discount rates up to 24% for A versus C, and 23% for A versus B. In addition, Alternative B beginning with a coal steam plant to delay the need for Kiambere, would be more costly than using gas turbines and geothermal for the same purpose for discount rates up to 22%. The present values of incremental costs of each alternative at varying discount rates are shown in Annex 21, in which a description and analysis of the alternative development programs are also given.

Sensitivity

7.15 Sensitivity tests have been carried out to determine the effects of a 10% increase in capital costs of the project and a 10% reduction in total demand as well as a reduction in coal costs to $50/ton. For project capital cost increases of 10%, Alternative A remains the least cost than competing alternatives for discount rates up to 21%, versus Alternative B, and 21% versus Alternative C. Alternative C results in a lower cost than B up to 21%. If coal costs are $50/ton, and project costs are +10%, Alternatives A and C still are less costly than B for discount rates up to 19% and 17% respectively. If total demand were to reduce by 10% through 1988 (corresponding to an average growth rate of about 4.2% p.a.) the need for Kiambere would be delayed by less than one year. The possibility of such a drop in growth is considered to be remote.

Economic Rate of Return

7.16 The economic rate of return of the project is the discount rate at which the present value of the capital and operating costs of the project equals the present value of incremental project benefits as measured by the value of production according to the existing average tariff of 0.70 KSh/kWh (effective June 1983) and attributable fuel savings in an average hydro year, assuming load growth at 6% p.a. The economic rate of return from the project would be 10%. This rate of return is a conservative estimate because it does not include non-quantifiable benefits to the country, always associated with the development of new power projects. Nevertheless, this rate of return is lower than the estimated opportunity cost of capital (about 12%). A tariff of 85 K cents/kWh effective June 1, 1983 would have been required to give a 12% rate of return. Should project costs increase by 10%, the rate of return would be 9.4%, while if total demand were 10% less than forecast (corresponding to an average growth rate of about 4% p.a. to 1988, increasing to about 5% by 1992) the economic rate of return is estimated to be 9.5% (Annex 22).

Long Run Marginal Cost

7.17 The Long Run Marginal Cost (LRMC) of power sales is estimated at 83.2 Kcts/kWh or about 17% higher than the present tariff of 70 Kcts/kWh plus 1 Kct tax. However, financial requirements will be met by the proposed tariff program (para. 5.12). Annex 23 gives details of the LRMC calculation.

Project Risks

7.18 Load growth: The future load growth accepted in this report is lower than the past growth and assumes that the existing economic recession will continue into the next decade. There is a slight chance that the actual growth could be lower than the estimates due to possible further economic deterioration. In that case, projects following the Kiambere power project would be rescheduled.

7.19 Tariffs: A further point of consideration is that of the tariff increases that are required in order to satisfy earning requirements; however, timely tariff increases have been introduced in the past, which suggest there is no undue risk in this respect. Experience in Kenya has shown no appreciable effect on growth of demand due to tariff increases except in the case of water heating when tariff increases have been designed to encourage use of solar water heaters, a desirable strategy which should continue. Since electricity amounts to less than 2% of total cost of all inputs used in Kenya's industrial sector, no effect on demand has been experienced in spite of doubling industrial tariffs since 1975. It is thus expected that the future demand growth would not be materially affected by the proposed tariff increases and that any effect has already been taken into account in projecting future demand.

7.20 Construction and project costs: Although site investigations and sub-surface exploration have shown that geological conditions of some areas of the underground excavation are not favorable, TARDA's consultants and the Bank's engineering geologist have not identified any potential risk that could be a problem for the physical construction of the project. All possible construction risks have been taken into consideration by TARDA's cost consultants and by the Bank's cost expert (para. 4.02).

7.21 The important risks are explained above. All other risks are considered to be minor and may be solved without any major cost increases. Bids will be received on May 18, 1983 so that the cost of major contracts would be known before Board presentation. No major physical risks are anticipated in implementing the proposed project beyond those that are normally expected in the construction of a project of this type and size.

VIII. AGREEMENTS REACHED AND RECOMMENDATION

Agreements Reached

8.01 During negotiations, agreement was reached with Government, KP&L and/or TARDA that:

(a) TARDA would employ engineering consultants, a panel of experts, a project team leader, and a financial manager satisfactory to the Bank (para. 4.09);

(b) the KP&L companies would submit annual accounts and annual consolidated accounts to the Bank within six months of the end of the financial year (para. 4.16);

(c) TARDA would submit its accounts to the Bank within six months of the fiscal year; and TARDA would submit appropriate data for sector earnings presentation by June 30 of each year (para. 4.17);

(d) KP&L would earn a rate of return of 8% in 1984 and 1985, 10% in 1986 and 1987 and 8% thereafter and during the construction period contribute at least 15% of total cost of the project (para. 5.12);

(e) suitable reports and records necessary to monitor the progress of the project and its evaluation would be submitted to the Bank (para. 6.13).

8.02 As conditions of effectiveness for the Bank Loan:

(a) the conditions of effectiveness of the other foreign financial loans would be met (para. 4.07); and

(b) the execution of the onlending agreement with TARDA and the lease agreement between TARDA and KP&L (para 5.17).

Recommendation

8.03 With the above agreements, the project would be suitable for a Bank loan of US$95.0 million equivalent (including US$0.2 million capitalized front-end fee) for a term of 20 years including a grace period of 5 years.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Existing Power Facilities

Existing Power Network

1. The existing power supply facilities of the interconnected system are mainly located at the more densely populated narrow strip running across the southern part of the country from Mombasa through Nairobi to Lake Victoria in parallel with the railway, and along the coast as shown on the map (Map IBRD 17029). The northern and eastern parts of the country are arid, and because of the scattered population, consumers do not have easy access to electricity.

2. A 132-kV powerline link connects Kenya and Uganda power grid (UEB), and Kenya imports power of about 30 MW per year. As of December 31, 1981, the total installed capacity of the interconnected system including the Uganda link (30-MW) is about 571-MW with an effective capacity of about 537 MW consisting of the following generating stations:

Station	Owner	Installed Capacity (MW)	Effective Capacity (MW)
Hydro			
Tana	KPC	14.4	12.4
Wanjii	KPC	7.4	7.4
Kamburu	TRDC	91.5	84.0
Gitaru	TRDC	145.0	145.0
Kindaruma	TRDC	44.0	44.0
KP&L 1/	KP&L	6.2	6.2
Masinga 2/	TARDA	40.0	40.0
UEB (imports) 3/	-	30.0	30.0
Total Hydro		378.5	369.0
Thermal			
Kipevu	KP&L	98.0	90.5
Olkaria (Geothermal)	KPC	30.0	30.0
Gas Turbine (Nairobi South)	KP&L	15.0	15.0
Gas Turbine (Kipevu)	KP&L	17.9	13.8
All Diesel Stations	KP&L	31.5	18.7
Total Thermal		192.4	168.0
TOTAL INTERCONNECTED SYSTEM		570.9	537.0

1/ Ndula, Mesco, Sagana Falls and Selby Falls
2/ During dry years its capacity reduces to 20 MW
3/ Imports from Uganda Electricity Board's hydro power plant

3. KP&L also has some small isolated diesel stations at Homa Bay, Kitale, Lamu and Garissa with a total capacity of about 2.2 MW.

4. KP&L's power interconnected system which operates at 132 kV, 66 kV, 40 kV, 33 kV, and 11 kV covers the coastal strip and the southern part of the country including Nairobi, the Coast, Western Kenya, Rift Valley and Mt. Kenya regions. Approximate maximum demand and energy sales of these regions are shown below:

Region	Maximum Demand (MW) in 1981	Sales GWh	Average % Increase -in last 5 years-- Demand	Sales
Nairobi	182	900	10.1	7.1
Coast	72	390	9.5	6.7
Western Kenya	39	180	14.1	11.6
Rift Valley	18	79	8.5	5.8
Mt. Kenya	12	44	7.5	3.1
Total System (simultaneous)	313	1.593	8.8	7.3

The Nairobi region is by far the largest.

5. The operating voltages and the length of the main power transmission lines located in various regions as of December 31, 1981 are summarized below:

Voltage (kV)	Total Circuit Length (km)
275	217
132	1,527 1/
66	368
40	113
33	2.042
11	5,704
TOTAL	9,971

1/ All lines are owned by KP&L, except the 132 kV Kamburu-Masinga line (about 25 km), which is owned by TARDA.

6. The operating voltages and the capacity of transformers in service are given below:

Substations	Number	Capacity (MVA)
Generating Station Substations		
11/132 kV	10	397 1/
11/66 kV	6	30
11/33 kV	8	137
11/40 kV	4	5
3.3/11/40 kV	2	8
3.3/40 kV	2	4
3.3/33 kV	1	2
Transmission Substations		
132/66 kV	6	195
132/33 kV	11	180
66/11 kV	26	323
66/40 kV	2	15
40/11 kV	6	16
33/11 kV	89	262
Distribution Transformers		
33/0.415 and 11/0.415 kV	5,705	789
	5,878	2,363

7. KP&L has an effective communication system throughout the country. It has used land mobile radio-telephone equipment satisfactorily for many years. Maintenance crews working on transmission lines and almost all important power plants and substantions are linked by radio-telephone. A powerline carrier (PLP) communication network has been used throughout the grid satisfactorily. The primary means of communication between the regional administrative centers and the headquarter and grid control center (load dispatching center) in Nairobi is the public telephone system as operated by the Kenya Post and Telecommunication corporation and KP&L's PLC system.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Statistical Data on Power System

	1977	1978	1979	1980	1981
Installed Generation Capacity (MW)					
Hydro	205	350	350	350	350
Steam	127	127	127	127	127
Diesel	31	31	31	31	31
Geothermal	-	-	-	-	15
Gas Turbine	30	30	30	30	30
Total	393	538	538	538	538
Power Production (GWh)					
Hydro	749	1,073	1,308	1,060	1,381
Thermal					
Purchase from Uganda	272	217	160	315	194
Total	1,405	1,529	1,655	1,735	1,879
Sales of Energy (GWH)					
Energy Sales	1,203	1,301	1,409	1,468[a/]	1,593
Station Use	28	25	22	29	29
System Losses	174	203	224	238	257
Total Energy Use	1,405	1,529	1,655	1,735	1,879
System Losses (%)	12.4	13.3	13.5	13.7	13.7
Peak Demand (MW) (Sales)					
Interconnected System	223	256	269	290	313
Isolated Systems	1	1	1	1	1
Total (arithmetic sum)	224	257	270	291	314
Consumption by Classification (GWh)					
Domestic & Small Commercial	339	360	385	402	438
Industrial & Large Commercial	742	814	891	944	1,026
Off-peak Sales	111	117	123	111	118
Street Lighting	11	10	10	11	11
Total	1,203	1,301	1,409	1,409	1,593
Percent Increase	11.2	8.1	8.3	4.2	8.5
Number of Connections	133,759	141,727	149,739	156,621	167,724

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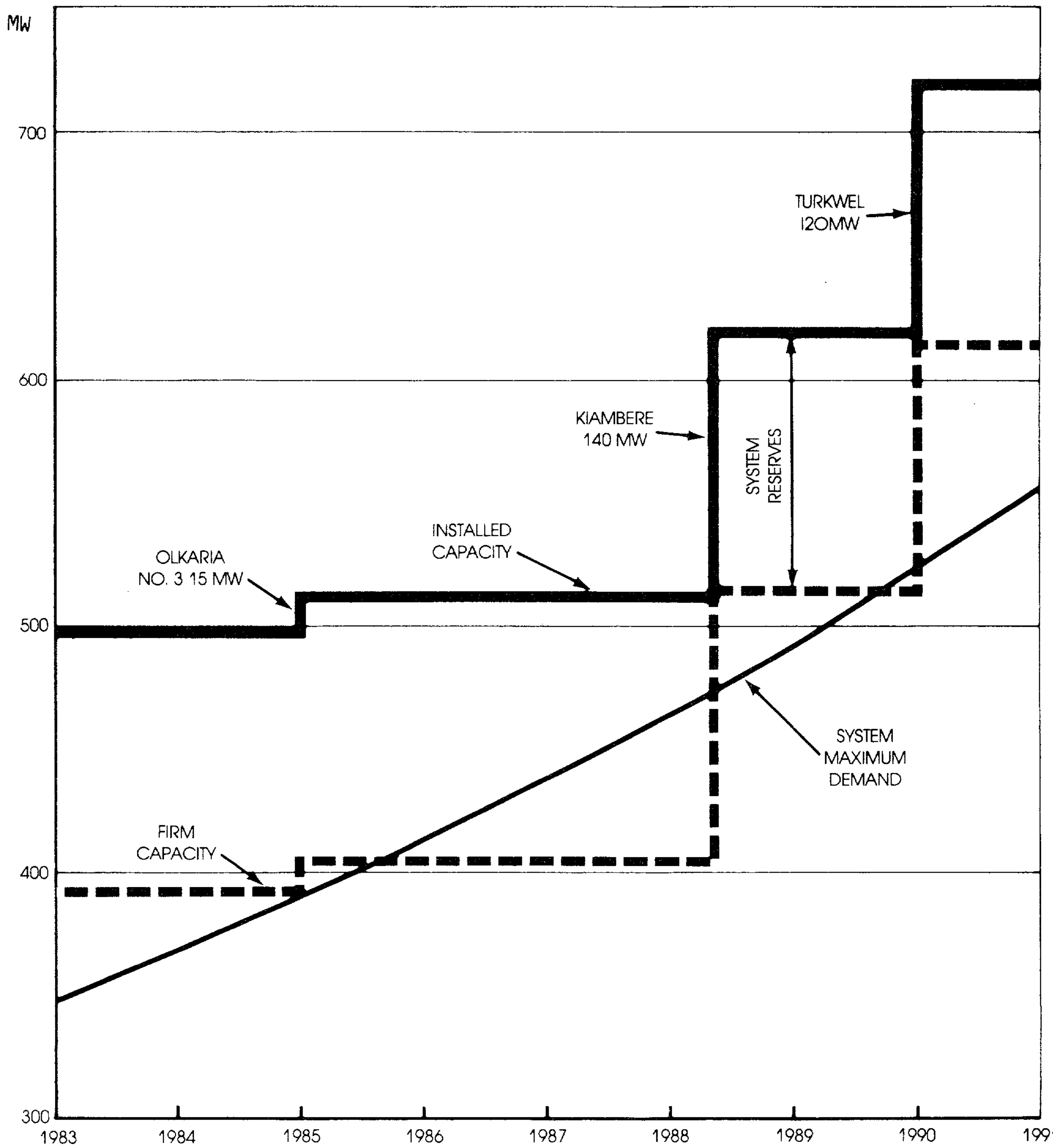
a/ KP&L applied a load shedding program in 1980.
Demand without load shedding estimated at about 1,508 GWh by KP&L

KENYA
KIAMBERE HYDROELECTRIC POWER PROJECT
Installed and Firm Capacity and Maximum Demand



KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Project Description

General Description

1. Kiambere Gorge offers particularly favorable prospects for hydropower development due to the steep gradient, promising dam sites and the fact that a sharp bend in the river valley offers construction of an aggregate of water passages (Map IBRD 16895).

2. The selected site is located on the Tana River some 150 km north-east of Nairobi and some 35 km downstream of the lowest of the existing hydropower stations at Kindaruma (para. 3.04), and as there are no major tributary inflows over the intervening reach, it is essentially in cascade with the Seven Forks stations (i.e. power stations between Masinga and Grand Falls). However, as described below, the intervening unregulated catchment will have a modest effect on yields and will also influence flood characteristics and sediment inflow to the Kiambere reservoir.

3. The land around the site is at present sparsely populated, although there is evidence that immigration to the area has significantly increased over the last few years (those people who have seen construction of roads, camps, and airstrips, and the site preparation started to immigrate for compensation), and is likely to continue due to population pressure in the uplands, generally improved access and the possiblities of employment offered by the new project.

4. The area is arid, with an average annual rainfall of 700 mm against a potential evaporation rate of 2100 mm/year. In consequence, agricultural potential is low and the predominant vegetation is thornbush and thicket.

Hydrology

5. Flow at the Kiambere site derives from two sources with fundamentally different hydrology: (i) highly regulated flows through reservoirs above Kiambere (Masinga and Kamburu) and (ii) unregulated seasonal run-off from the intermediate catchment downstream of Kamburu. Flows to Kamburu are regulated through Masinga reservoir, with a storage of 1,400 million m^3, which allows seasonal regulation of the river flows. The hydrology of these flows has been well established over the course of a number of previous studies and the record has recently been updated by TARDA. It is estimated that the contribution of the unregulated area will be only about 8% of the total flow at Kiambere. The total average flow at Kiambere is about 113 m^3/sec (30 years period 1947-77). Dry season flows are unlikely to drop below 37 m^3/sec. Flood flow, taking the upper reservoir only, is calculated to give a peak flow of 5,500 m^3/sec, one in 10,000.

Geology

6. The Kiambere site is located on rocks of the basement system, which are derived from Pre-Cambrian sediments that have been subjected to cyclic tectonic movements. The dominant rock types are gneisses and granites. There is considerable surface evidence of past faulting, shearing and jointing in the area as might be expected from the geological history. However, as these movements are now considered to be long inactive, the presence of such fracturing in the rock should not be detrimental to the planned project, given adequate sub-surface preparation.

7. In general the geological situation at the dam site is comparatively favorable and is less favorable at the shaft, surge chamber and the saddle dam areas. TARDA employed independent geological and hydrological conditions (based on the terms of reference approved by the Bank) to comment on the original design. Design review consultants have also made recommendations on construction methods. An engineering geologist also participated in the appraisal mission. In general the consultants have not identified any risks other than those normally associated with this type of project and no major geological difficulties should be experienced during the construction.

General Layout

8. The Kiambere hydroelectric project comprises: a 110 m high earthfill embankment dam on the Tana River; a 35 m high zoned--also earthfill--dam closing a low saddle; a free overfall side channel spillway, discharging through a chute in the left bank and a fuse plug emergency spillway adjacent to the saddle dam; two diversion tunnels, each 0.5 km long, through the left abutment; an intake structure leading to a 6.1 m equivalent diameter headrace tunnel 4 km long, with a 20 m diameter surge chamber; twin vertical penstock tunnels; an underground powerhouse containing two 70-MW generators driving by vertical Francis type turbines; a 6.2 m equivalent diameter tailrace tunnel with the helical surge tunnel; switchyard; two single circuit 220-kV transmission lines each approximately 40 km long; and access roads, etc.

Preliminary Works

9. Preliminary works already completed or presently under construction include: an existing camp at Kamburu; a new camp at Kiambere; a 31 km long access road connecting the site to the Kangodi to Embu government road; and a gravel surface airfield suitable for light aircraft at Kambere. The general layout is shown on Map IBRD 16895.

Dams

10. There are approximately 8,500,000 m^3 of fill and 1,500,000 m^3 of excavation in various structures. Core and shell material for the dams will be borrowed within 2 to 4 km from the site. Sand for filters will be borrowed from a pit again about 4 km from the dam site. Total quantity of concrete required for the project is approximately 185,000 m^3 including overbreak. All the cement for the project would be supplied by local market.

Spillways

11. The spillway will be located on the left bank of the river where a spur protruding into the main valley provides a suitable position for the construction of the overflow section and low velocity trough. The crest will have a length of 300 m. Two 3.2 m by 2.5 m vertical left gates will be located in an outlet structure at the upstream end of the spillway trough. There gates will enable releases of compensation water of up to 50 m^3/sec to be made during periods when the power station is out of commission.

12. The emergency spillway will be of the erodable fuse plug embankment type and will be located adjacent to the saddle dam at the head of the Irinde Valley.

Diversion Tunnels

13. The first diversion tunnel will have a length of 610 m and will be of a modified horseshoe cross-section with a diameter of 10 m. It will be concrete lined throughout its length in order to improve the hydraulic efficiency and increase the discharge capacity. The second diversion tunnel will be unlined with a concrete invert except in areas of poor rock conditions where a full concrete lining will be provided. This tunnel will be 8.5 m in diameter and 540 m in length.

Cofferdams and Low Level Outlet

14. The main dam will incorporate the cofferdams and will permit the diversion of water during the initial construction period.

15. In order to maintain river flows to downstream users both during the period of initial filling of the reservor and subsequently in the event of outage at the power station, a low level outlet will be provided, located in a bypass tunnel adjacent to the first diversion tunnel. In addition to its use in maintaining discharge to downstream users, the facility will also permit the lake to be drawn down for maintenance works to be carried out or in the interest of safety. The discharge capacity will be about 80 m^3/sec (average).

Water Intake and Headrace Tunnel

16. The intake structure will control the entry of water into the headrace tunnel. The structure will contain the trash racks and to prevent entry of debris, and intake gates which will permit the headrace to be sealed and drained. The headrace tunnel will extend some 4,060 m from the intake to the penstock bifurcation. The tunnel has been optimized as a 6.1 m equivalent diameter concrete-lined horseshoe tunnel, unless the geological conditions allow some unlined portions.

Shafts

17. Twin pressure shafts 80 m deep and horizontal penstocks 30 m long will connect the headrace tunnel to the turbines in the underground power

house. Penstocks will have a diameter of 4.0 m. A concentric conical taper will be provided at the downstream ends of each penstock to reduce the size to that of the main turbine values, which have been optimized at a 3.0 m diameter. Above the pressure shafts twin butterfly valves will permit each penstock to be sealed off and dewatered for maintenance purposes without affecting power generation through the other unit.

Headrace Surge Chamber and Tailrace Tunnel

18. The headrace surge chamber will limit the amplitude of transient pressure waves resulting from regulation of flow to the turbines in the pressure shafts and penstocks. The chamber is a simple circular tank some 16.5 m in diameter. The chamber will be formed in reinforced concrete.

19. The tailrace tunnel will extend some 1,400 m from the powerhouse to the outfall in the Tana River adjacent to the Thura confluence. The tunnel has been optimized as a 6.35 m equivalent diameter concrete-lined horseshoe section. An outfall structure will be provided at the downstream portal of the tailrace tunnel to facilitate closure of the tunnel for dewatering. The structure will comprise a reinforced concrete operating platform constructed above the tunnel portal and will carry the gate hoist gantry and storage bins for the gates.

Power House and Switchyard

20. The underground powerhouse will be located in a geologically stable block below a small plateau some 1.4 km south of the Thura confluence with the Tana River. The access tunnel will be some 450 m long and driven at a fall of 1 in 10 to provide vehicular access to the machine hall. The horseshoe-shaped tunnel will be about 6 m high and 5 m wide. Once the access tunnel has been driven to the vicinity of the machine hall, a specialist sub-contractor will be called in to measure the principal stress in the rock. This information will permit the optimum orientation and design of the major cavern excavation to be determined. A circular service shaft 7 m in diameter and about 180 m deep will extend from the loading bay side adit up to the control building and will accommodate the main ventilation duct, lift shaft, stairs and cable ducts.

21. The control building will be situated at ground level directly above the service shaft providing access to the underground machine hall below. The building will be a three-storied, concrete-framed and masonry-clad structure.

22. The switchyard will be situated to the south of the control building and will be constructed on a level plateau formed in tunnel spoil.

23. The underground powerhouse will be 18 m wide and 50 m long, and will contain a turbine generator hall and a loading bay. The loading bay and powerhouse will be serviced by two cranes, which can be coupled together to provide a gross lifting capacity of 230 tonnes. The powerhouse will have cooling water, potable water, and a compressed air system, ventilation and air conditioning. An appropriate drainage system will also be constructed. Auxiliary power and emergency start systems, power line

carrier, and telephone system will also be located at the powerhouse and control room. Electricity will be generated at 11 kV and two 85 MVA transformers will raise the power produced to 240 kV.

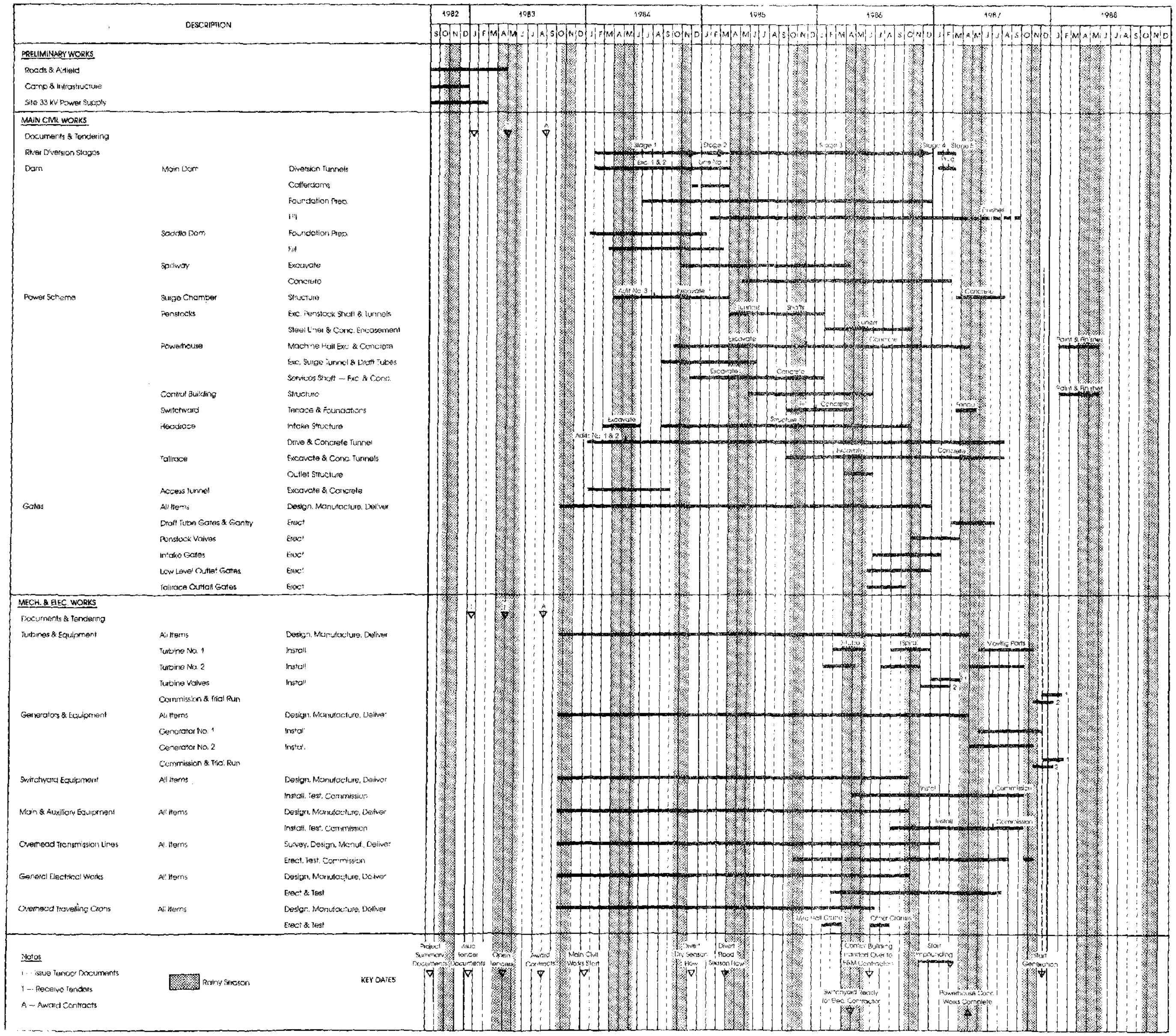
KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Proposed Financing Plan
(US$ millions)

	IBRD		SAUDI FUND		AFDB		Other Colenders		TARDA		GOVT 1/		TOTAL		TOTAL
	L	F	L	F	L	F	L	F	L	F	L	F	L	F	
Preliminary Works									16.4				16.4		14.1
Dams	35.5	1.6		11.5		21.7	5.7	5.7			13.7		54.9	40.5	95.4
Power House and Access							7.6	28.2	7.5		9.2		24.3	28.2	52.5
Tunnels							13.2	22.5			9.6		22.8	22.4	45.2
Mechanical & Electrical							4.4	39.6			13.7		18.1	39.6	57.7
Consultant Pre Nov. 1 1982	3.7	25.1							5.4				5.4		5.4
Consultant Post Nov. 1 1982									5.2				8.9	25.1	34.0
Experts and Project Leader	.4	1.2											.4	1.2	1.6
Miscellaneous									3.6				3.6		3.6
Total Project Cost	39.6	27.9		11.5		21.7	30.9	95.9	38.1		46.2		154.8	157.0	311.8
IDC Bank Loan		27.3												27.3	27.3
IDC Other Lenders								4.5	10.				10.0	4.5	14.5
Front End Fee		.2												.2	.2
	39.6	55.4		11.5		21.7	30.9	100.4	48.1		46.2		164.8	189.0	353.8
	95.0		11.5		21.7		131.3		48.1		46.2				

KENYA
KIAMBERE HYDROELECTRIC POWER PROJECT
Project Implementation Schedule



KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

DISBURSEMENT SCHEDULE

(US$ million)

IBRD Fiscal Year Quarter Ending	Quarterly Disbursement	Cummulative Disbursement at End of Quarter
1984		
March 31, 1984	8	8
June 30, 1984	4	12
1985		
September 30, 1984	4	16
December 31, 1984	8	24
March 31, 1985	7	31
June 30, 1985	6	37
1986		
September 30, 1985	5	42
December 31, 1985	5	47
March 31, 1986	5	52
June 30, 1986	5	57
1987		
September 30, 1986	5	62
December 31, 1986	4	66
March 31, 1987	4	70
June 30, 1987	4	74
1988		
September 30, 1987	4	78
December 31, 1987	4	82
March 31, 1988	4	86
June 30, 1988	3	89
1989		
September 30, 1988	2	91
December 31, 1988	2	93
March 31, 1989	1	94
June 30, 1989	1	95

ANNEX 7

THE KENYA POWER COMPANY LIMITED
TANA RIVER DEVELOPMENT COMPANY LIMITED
THE EAST AFRICAN POWER AND LIGHTING COMPANY LIMITED
COMBINED INCOME STATEMENT FOR THE YEARS 1979-1990
(KSh Million)

	ACTUAL				ESTIMATED							
	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SALES IN GWH												
DOMESTIC	385.6	400.0	434.9	451.7	493.0	528.0	565.0	604.0	646.0	702.0	755.0	810.0
LIGHT/POWER	425.2	437.1	410.6	406.5	451.0	477.0	506.0	537.0	571.0	605.0	643.0	682.0
INDUSTRIAL	463.0	506.5	615.0	644.5	682.0	725.0	770.0	819.0	867.0	911.0	960.0	1014.0
OFF PEAK	122.6	111.4	117.8	114.1	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
STREET LIGHT	10.1	10.7	11.0	11.1	11.0	11.0	12.0	12.0	12.0	12.0	13.0	13.0
STAFF	3.0	2.9	3.2	3.4	3.0	4.0	4.0	4.0	5.0	5.0	5.0	6.0
TOTAL	1409.5	1468.6	1592.5	1631.3	1760.0	1865.0	1977.0	2096.0	2221.0	2355.0	2496.0	2645.0
OPERATING REVENUES												
DOMESTIC	205.9	215.0	232.9	241.9	368.3	394.4	422.1	451.2	482.6	524.4	564.0	605.1
LIGHT/POWER	192.1	197.8	189.7	196.8	304.0	321.5	341.0	361.9	384.9	407.8	433.4	459.7
INDUSTRIAL	142.9	158.1	191.5	194.4	356.7	379.2	402.7	428.3	453.4	476.5	502.1	530.3
OFF PEAK	25.9	24.6	25.6	24.7	51.5	51.5	51.5	51.5	51.5	51.5	51.5	51.5
STREET LIGHT	4.8	5.2	5.3	5.3	7.6	7.6	8.3	8.3	8.3	8.3	9.0	9.0
STAFF	0.5	0.5	0.7	0.7	1.3	1.7	1.7	1.7	2.1	2.1	2.1	2.6
FUEL SURCHARGE	0.0	97.0	271.9	345.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL SALES REVENUES	572.1	698.2	917.6	1009.6	1089.4	1155.9	1227.3	1302.9	1382.8	1470.6	1562.1	1658.2
OTHER	1.7	3.3	2.4	10.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TARIFF INCREASE	0.0	0.0	0.0	0.0	85.0	299.4	476.2	674.9	894.7	1120.6	1382.5	1674.8
TOTAL	573.8	701.5	920.0	1020.5	1174.4	1455.3	1703.5	1977.8	2277.5	2591.2	2944.6	3333.0
OPERATING EXPENSES												
OPER & ADM	129.6	167.0	192.2	258.8	304.8	346.7	396.6	423.5	486.4	569.8	666.6	771.3
FUEL	79.6	235.4	163.9	174.0	133.5	104.1	161.8	209.8	280.5	113.9	140.8	76.1
PURCHASED ENERGY	7.3	19.6	63.5	84.8	92.8	119.0	120.0	124.8	126.1	118.7	121.3	117.8
DEV SURCH TARDA	0.0	0.0	0.0	0.0	51.5	81.1	122.6	133.2	182.9	57.2	0.0	0.0
DEV SUR KVA	0.0	0.0	0.0	0.0	0.0	0.0	88.2	100.4	147.7	166.7	187.2	103.6
COST TARDA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	434.2	434.2
COST KVA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	145.7
DEPRECIATION	68.2	69.4	72.2	95.1	166.5	227.9	254.7	295.4	328.5	368.4	406.8	449.4
TAXES	54.7	-4.1	6.0	74.0	111.0	192.0	148.0	192.0	208.0	432.0	343.0	419.0
TOTAL	339.4	487.3	497.8	686.7	860.1	1070.8	1291.9	1479.1	1760.1	1826.7	2299.9	2517.1
OPERATING INCOME	234.4	214.2	422.2	333.8	314.3	384.5	411.6	498.7	517.4	764.5	644.7	815.9
OTHER INCOME	-18.2	31.8	-172.9	-167.2	0.0	-0.0	0.0	0.0	0.0	-0.0	-0.0	-0.0
NET INCOME BEF INT	216.2	246.0	249.3	166.6	314.3	384.5	411.6	498.7	517.4	764.5	644.7	815.9
INT CHARGED OP	102.3	97.7	104.6	117.7	135.6	145.2	201.8	251.5	240.0	230.0	213.1	193.3
NET INCOME	113.9	148.3	144.7	48.9	178.7	239.3	209.8	247.2	277.4	534.5	431.6	622.6

ANNEX 8

THE KENYA POWER COMPANY LIMITED
TANA RIVER DEVELOPMENT COMPANY LIMITED
THE EAST AFRICAN POWER AND LIGHTING COMPANY LIMITED
COMBINED BALANCE SHEETS FOR THE YEARS 1979-1990
(KSh Million)

	ACTUAL				ESTIMATED							
	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ASSETS												
PLANT IN OPERATION	2446.8	2461.2	2923.1	5571.8	7244.1	8046.6	9329.9	10314.3	11473.7	12604.5	13849.4	15232.6
LESS: DEPRECIATION	515.7	579.8	649.7	1399.3	1693.1	2065.0	2474.7	2955.7	3505.9	4137.2	4854.2	5667.6
NET PLANT	1931.1	1881.4	2273.4	4172.5	5551.0	5981.6	6855.2	7358.6	7967.8	8467.3	8995.2	9565.0
WORK IN PROGRESS	175.4	450.0	655.8	903.4	469.6	784.0	470.1	646.0	902.6	1366.6	2021.3	3200.2
L/T INVESTMENTS	32.2	11.8	18.6	17.0	39.0	68.0	83.0	98.0	103.0	111.0	124.0	151.0
CURRENT ASSETS												
-CASH	0.0	0.0	0.0	0.0	17.3	37.5	0.0	0.0	27.2	125.8	56.2	22.6
-OPERATIONAL REQUIREMENTS	198.7	37.9	52.6	9.5	185.1	204.8	158.9	184.1	209.2	535.3	513.5	638.2
-ACCOUNTS REC	95.3	133.5	165.8	156.7	211.4	262.0	306.6	356.0	409.9	466.4	530.0	599.9
-INVENTORIES	117.6	181.7	241.8	294.3	347.8	401.8	464.8	538.8	566.8	634.8	710.8	797.8
-OTHER	10.5	13.9	26.1	50.2	36.8	44.4	51.1	58.5	66.6	75.1	84.6	95.1
-OTHER	7.6	78.6	3.0	2.7	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
-TARDA	0.0	0.0	0.0	128.8	100.0	75.0	50.0	25.0	0.0	0.0	0.0	0.0
TOTAL	429.7	445.6	489.3	642.2	901.5	1028.6	1034.5	1165.5	1282.8	1840.5	1898.2	2156.7
TOTAL	2568.4	2788.8	3437.1	5735.1	6961.1	7862.2	8442.8	9268.1	10256.2	11785.4	13038.7	15072.9
LIABILITIES												
EQUITY												
-CAPITAL	360.0	380.0	387.9	387.9	434.4	475.8	494.8	508.8	533.2	559.8	599.4	696.8
-RETAINED EARNINGS	260.7	297.5	365.0	541.3	671.7	871.6	1029.7	1235.2	1470.5	1972.6	2382.7	2977.5
-GRANTS	4.5	35.1	0.1	0.0	0.0	0.0	1.4	16.2	45.1	81.6	126.6	179.5
-CAPITAL RESERVE	56.0	94.4	102.3	121.4	143.4	172.4	187.4	202.4	207.4	215.4	228.4	255.4
-CAPITAL RESERVEII	419.0	446.4	486.4	321.7	324.7	311.8	325.2	328.6	342.4	343.5	328.7	306.2
-REVALUATION RESER	0.0	0.0	0.0	1526.9	1906.6	2378.3	2826.7	3340.8	3892.7	4490.4	5125.5	5800.3
TOTAL	1100.2	1253.4	1341.7	2899.2	3480.8	4209.9	4865.2	5632.0	6491.3	7663.3	8791.3	10215.7
LONG TERM DEBT	1236.7	1245.6	1850.5	2475.4	2892.7	3000.1	2959.5	2942.5	3033.0	3116.8	3304.9	3820.5
CURRENT LIABILITIES												
-ACCOUNTS PAYABLE	192.0	213.0	228.3	282.1	465.0	448.6	455.8	459.7	512.3	561.7	587.9	606.1
-OTHER	10.2	57.4	9.1	16.9	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
-OTHER II	29.3	19.4	7.5	56.0	111.0	192.0	148.0	192.0	208.0	432.0	343.0	419.0
-OVERDRAFTS	0.0	0.0	0.0	5.5	0.0	0.0	2.7	30.3	0.0	0.0	0.0	0.0
TOTAL	231.5	289.8	244.9	360.5	587.6	652.2	618.1	693.6	731.9	1005.3	942.5	1036.7
TOTAL	2568.4	2788.8	3437.1	5735.1	6961.1	7862.2	8442.8	9268.1	10256.2	11785.4	13038.7	15072.9
DEBT/DEBT & EQUITY	52.9	49.8	58.0	46.1	45.4	41.6	37.8	34.3	31.8	28.9	27.3	27.2
DEBT/EQUITY	1.1	1.0	1.4	0.9	0.8	0.7	0.6	0.5	0.5	0.4	0.4	0.4
CURRENT RATIO	1.9	1.5	2.0	1.8	1.5	1.6	1.7	1.7	1.8	1.8	2.0	2.1

ANNEX 9

THE KENYA POWER COMPANY LIMITED
TANA RIVER DEVELOPMENT COMPANY LIMITED
THE EAST AFRICAN POWER AND LIGHTING COMPANY LIMITED
COMBINED STATEMENT OF SOURCES AND APPLICATION OF
FUNDS FOR THE YEARS 1979-1990
(KSh Million)

	ACTUAL				ESTIMATED							
	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
INTERNAL SOURCES												
-NET INCOME BEF IN	216.2	246.0	249.3	166.6	314.3	384.5	411.6	498.7	517.4	764.5	644.7	815.9
-DEPRECIATION	68.2	69.4	72.2	95.1	166.5	227.9	254.7	295.4	328.5	368.4	406.8	449.4
-PLANT DISPOSALS	4.1	4.8	1.2	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-EXCH DIFF	44.0	-10.9	201.8	202.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-INVESTMENTS	2.3	22.5	5.1	12.9	2.7	2.9	3.1	3.4	3.8	1.7	1.8	2.0
TOTAL	334.8	331.8	529.6	480.0	483.5	615.3	669.4	797.5	849.7	1134.6	1053.3	1267.3
OPERATIONAL REQUIREMENTS												
-CHAN'G WORK'G CAP.	67.4	-42.4	88.6	42.8	9.4	42.3	80.2	83.1	21.5	185.7	190.1	197.9
-DEBT SERVICE	169.6	172.1	190.3	223.0	279.2	270.8	351.9	405.9	433.3	510.3	526.9	568.7
-DIVIDENDS	20.8	12.9	21.7	18.4	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
TOTAL	257.8	142.6	300.6	284.2	311.9	336.4	455.4	512.3	478.1	719.3	740.3	789.9
NET AVAILABLE FROM OPERATIONS	77.0	189.2	229.0	195.8	171.6	278.9	214.0	285.2	371.6	415.3	313.0	477.4
CONSTRUCTION REQUIREMENTS												
-ONGOING WORKS	133.4	314.8	662.5	719.0	161.9	178.0	198.1	225.1	227.5	261.0	299.6	344.4
-GEOTHERMAL 3	0.0	0.0	0.0	0.0	216.3	182.3	45.6	11.7	0.0	0.0	0.0	0.0
-GEOTHERMAL 4 & 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.4	101.8	192.5	595.1
-DRILLING	0.0	0.0	0.0	0.0	71.9	79.4	87.0	95.0	103.8	113.5	124.3	136.2
-SUBSTATION	0.0	0.0	0.0	0.0	0.0	0.0	13.9	76.3	60.4	7.3	0.0	0.0
-220-KV MOMBASA/KAMBURU	0.0	0.0	0.0	0.0	256.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0
-220-KV MOMBASA/NAIROBI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	124.5	197.6	252.4	305.0
-L/T INVESTMENTS	19.0	2.1	11.9	11.3	24.7	31.9	18.1	18.4	8.8	9.7	14.8	29.0
TOTAL	152.4	316.9	674.4	730.3	730.8	501.6	362.7	465.0	619.4	690.9	883.6	1409.7
BALANCE TO FINANCE	75.4	127.7	445.4	534.5	559.2	222.7	148.7	179.8	247.8	275.6	570.6	932.3
FINANCED BY:												
-BORROWINGS	60.4	107.7	445.4	529.0	535.5	201.5	88.1	123.4	252.0	311.1	416.4	748.4
-EQUITY	15.0	20.0	0.0	0.0	46.5	41.4	19.0	14.0	24.4	26.6	39.6	97.4
-GRANTS	0.0	0.0	0.0	0.0	0.0	0.0	1.4	14.8	28.9	36.5	45.0	52.9
TOTAL	75.4	127.7	445.4	529.0	582.0	242.9	108.5	152.2	305.3	374.2	501.0	898.7
DEBT SERVICE COVER	2.0	1.9	2.8	2.2	1.7	2.3	1.9	2.0	2.0	2.2	2.0	2.2

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Notes and Assumptions for Financial Statements

Sales and Revenues

1. KP&L's energy sales for each customer category appear in Annex 7. Revenues from 1983 onwards are based on tariff increase of 13% effective on June 1, 1983, and further yearly tariff increases of Ksh 0.08 effective each January 1 up to 1990.

2. A consumption tax of 1 cent per kWh is levied on all energy sales.

3. The revenues of KPC and TRDC are their respective ascertained cost, the amount payable by KP&L for electricity purchased from both companies, which is described in para. 4. The ascertained cost of TARDA and KVA is based on their debt service plus a fixed charge to cover their administrative cost related to their power activities and is described in para. 5. The ascertained costs of all power companies include a development surchage as described in para. 6 below.

Ascertained Cost

4. The bulk supply licenses of KPC and TRDC define ascertained cost (on the basis of which their revenues are determined) as the actual audited cost each year for the followig items:

(a) Operations and administration. This also icludes the cost of purchasing power from Uganda and from TARDA.

(b) Interest and redemption payments for debt;

(c) Income and other taxes; and

(d) Such other charges as the Government shall consider proper to be allowed. Under this authority a development surcharge (described later in this annex) has been added, starting 1971 for TRDC and 1979 for KPC, as part of their respective ascertained cost.

In addition, ascertained cost includes small annual appropriations to a Reserve and Equalization Fund which, with the interest on the securities in which it is invested, is available for future capital expenditure or to cover deficiencies in income and to pay for abnormal expenses.

5. In the proposed lease agreement for the Kiambere hydroelectric project 1/, KP&L has agreed to pay for the electricity purchased from TARDA on the following basis:

1/ It is assumed that a similar lease agreement will be drawn up between EAP&L and KVA prior to the implementation of Turkwel hydroelectric project commencing in 1985.

(a) All amounts due and payable by TARDA as principal, other charges and interest on the outstanding balance of all external loans directly contracted by TARDA for Kiambere;

(b) The principal amount required by TARDA to service its loan from the Government for Kiambere and interest on the outstanding balance of the loan; and

(c) An annual fixed charge to cover TARDA's administrative cost related to its power activities.

Development Surcharge

6. Development surcharge was principally designed to provide TRDC and KPC with part of the funds required to pay the local currency costs of their development projects as part of the cost of electricity KP&L purchases from TRDC and KPC and is determined each year in relation to their respective development activities. According to the lease agreement between KP&L and TARDA, a development surcharge at a minimum amount of 15% of the total cost of Kiambere will be paid to TARDA during the implementation of the project.

Fuel Cost and Purchased Energy

7. Fuel use for operating the KP&L group's plants is assumed to decrease with the commissioning of a 15 MW geothermal unit at the end of 1982 and to increase with the load growth from 1985 to 1988 when the commissioning of Kiambere and Turkwell, in mid-1988 and mid-1990, respectively, will cause the fuel use to decrease. A provision for price escalation of 7.5% and 7% for 1983 and 1984, respectively, has been made and 6% for 1985 to 1990.

8. KPC's annual purchases from UEB are assumed to be constant at 252 GWh at a total annual cost of KSh 15.9 million from 1983 onwards under the existing contract. TRDC is assumed to purchase 85 GWh in 1983, 167 GWh in 1984, 170 GWh in 1985, 185 GWh in 1986, 189 GWh in 1987, 166 GWh in 1988 (commissioning of Kiambere), 174 GWh in 1989 and 163 GWh in 1990 from TARDA's Masinga dam power stations at 0.32/kWh and a yearly fixed charge of KSh 49.7 million. The estimated cost of this energy is based on a revised agreement for electricity purchases by TRDC from TARDA.

Operating and Administration Expenses

9. No increase in volume of operations are reflected in TRDC. For KPC, due to the addition of two geothermal units in 1983 and 1985 respectively, the expenses are expected to increase on an average by KSh 3 million for each unit. KP&L's distribution cost is expected to increase by 2% annually; the commissioning of Kiambere in mid-1988 will increase operating/administration and insurance cost by KSh 17 million annually; and the commissioning of Turkwell in mid-1990 will increase cost for that year by KSh 5.5 million (Ksh5 million for operating/administration and KSh6 million for insurance annually).

10. In addition, provision for price escalations of 12% has been made for 1983 to 1990.

Depreciation

11. Depreciation is charged as a percentage of the revalued fixed assets at the beginning of each year - KP&L 4.0%, KPC 2.9%, and TRDC 2.2%. A depreciation rate of 5.1% on historical fixed assets has been used to calculate KP&L's income tax. These rates are consistent with past experience. The depreciation for the years 1979 to 1982 is computed on the historical cost of fixed assets, whereas for the period after 1982, it has been calculated on revalued fixed assets.

Taxes

12. TRDC and KPC's incomes are exempt from income tax. KP&L's income is subject to tax at present at the rate of 45%.

Dividends

13. Dividends on 4% and 7% preferred stock are KSh 1.9 million per year. Dividends on common stock of KP&L are assumed to be at the level of 13% for 1983 onwards.

Fixed Assets

14. Fixed assets and depreciation for the years 1979 through 1982 are at cost as shown in audited accounts. In 1983 and 1984, fixed assets and accumulated depreciation have been increased to reflect estimated replacement values by 9.1% and 8.5%, respectively and 7.5% for 1985 onwards to reflect estimated price escalations in those years.

KP&L's Account Receivables

15. These are assumed to be 18% of total revenues in accordance with recent past experience.

Inventories

16. KP&L inventories are assumed to be about 10% of gross revalued plant in operation while those of KPC and TRDC are assumed to be constant.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

OPERATING RESULTS - POWER SECTOR

For the Years Ending December 31, 1983-1990
(KSh millions)

	1983	1984	1985	1986	1987	1988	1989	1990
Net Operating Income - Consolidated EAP&L Companies	314.3	384.5	411.6	498.7	517.4	764.5	644.7	815.9
Add: Masinga Bulk Power Charges	76.9	103.1	104.1	108.9	110.2	102.8	105.4	101.9
Kiambere Development Surcharge	51.5	81.1	122.6	133.2	182.9	57.2	-	-
Kiambere Lease Payments - Debt Service							434.2	434.2
- Administration							4.0	4.0
Turkwel Development Surcharge			88.2	100.4	147.7	166.7	187.2	103.6
Turkwel Lease Payment - Debt Service								143.7
- Administration								2.0
Total Additions	128.4	184.2	314.9	342.5	440.8	326.7	730.8	789.4
Less: TARDA Depreciation	20.8	23.5	25.6	27.6	29.6	31.9	136.1	146.3
TARDA Administration Costs	2.1	2.3	2.7	3.0	3.4	3.8	4.3	4.7
Turkwel Administrative Costs								2.0
	22.9	25.8	28.3	30.6	33.0	35.7	140.4	153.0
Net Operating Income for Power Sector	419.8	542.9	698.2	810.6	925.2	1055.5	1235.1	1452.3
Average Net Fixed Assets - Revalued Base								
EAP&L Group	4861.8	5766.3	6418.4	7106.9	7663.2	8217.6	8731.3	9280.1
TARDA	995.6	1082.0	1148.3	1210.5	1272.6	3649.8	6152.0	6472.1
KVA								1984.5
Total Average Net Fixed Assets	5857.4	6848.3	7566.7	8317.4	8935.8	11867.4	14883.3	17736.7
Rate of Return (%)	7.2	7.9	9.2	9.7	10.4	8.9	8.3	8.2

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

TANA AND ATHI RIVERS DEVELOPMENT AUTHORITY (TARDA)

INCOME STATEMENT

For the years ending June 30, 1980/1990
(Ksh millions)

	Actual		Proposed	Forecast							
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Power Revenue											
Power Sales			90.7	72.0	90.0	103.6	106.5	104.6	106.5	104.1	103.6
Leasehold Receipts - Development Surcharge				25.7	66.3	101.9	127.9	158.0	120.1	28.6	
Debt Service										217.1	434.2
Administrative Expense										4.0	4.0
Total Power Revenue			90.7	97.7	156.3	205.5	234.4	262.6	226.6	353.8	541.8
Power Expenses											
Salaries and Wages			.5	.6	.7	.8	.9	1.0	1.2	1.3	1.5
Transport Costs			.3	.4	.5	.6	.7	.8	.9	1.0	1.2
Office Expense			.6	.7	.8	.9	1.0	1.2	1.3	1.5	1.7
Depreciation Revalued Asset Base				20.1	23.4	25.6	27.8	29.9	32.2	34.6	138.9
Other			.1	.2	.2	.2	.2	.2	.2	.2	.2
Total Power Expenses			1.5	22.0	25.6	28.1	30.6	33.1	35.8	38.6	143.5
Net Power Income			89.2	75.7	130.7	177.4	203.8	229.5	190.8	315.2	398.3
Other Revenues											
Government Grants	15.2	26.0	10.4	10.4							
Miscellaneous Income	.1	.6	2.4	2.8	3.2	3.6	4.0	4.5	5.0	5.6	6.3
Total Other Revenue	15.3	26.6	12.8	2.8	3.2	3.6	4.0	4.5	5.0	5.6	6.3
Other Expenses											
Administration	6.7	9.4	12.6	14.9	17.3	19.7	22.2	25.0	28.1	31.6	35.5
Depreciation	.9	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Asset Write-off			245.6								
Interest Expense				28.2	27.6	27.0	26.4	25.7	25.1	193.4	357.5
Total Other Expenses	7.6	10.4	259.3	44.2	46.0	47.8	49.7	51.8	54.3	226.1	394.1
Net Other Income (Loss)	7.7	16.2	(246.5)	(41.4)	(42.8)	(44.2)	(45.7)	(47.3)	(49.3)	(220.5)	(387.8)
Net Income (Loss)	7.7	16.2	(157.3)	34.3	87.9	133.2	158.1	182.2	141.5	94.7	10.5

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

TANA AND ATHI RIVERS DEVELOPMENT AUTHORITY (TARDA)

BALANCE SHEET

For the years ending June 30, 1980/1990
(Million KSh)

	Actual		Provisional	Forecast							
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Assets											
Fixed Assets											
Power Assets In Operation	.4	.4	913.5	1064.0	1164.4	1262.3	1360.1	1462.1	1571.8	6314.7	6788.3
Less Accumulated Depreciation				20.1	45.4	74.8	108.4	146.4	189.6	238.4	395.2
Net Power Assets In Operation	.4	.4	913.5	1043.9	1119.0	1187.5	1251.7	1315.7	1382.2	6076.3	6393.1
Other Assets											
Plant Under Construction	740.3	1051.7	42.0	384.4	1035.2	1892.0	2924.8	3861.2	4448.2		
Other Fixed Assets	4.8	5.3	6.4	7.5	8.6	9.7	10.8	11.9	13.0	14.1	15.2
Other Fixed Assets-Accumulated Depreciation	1.5	2.4	3.5	4.6	5.7	6.8	7.9	9.0	10.1	11.2	12.3
Net Other Fixed Assets	743.6	1054.6	44.9	387.3	1038.1	1894.9	2927.7	3864.1	4451.1	2.9	2.9
Net Fixed Assets	744.0	1055.0	958.4	1431.2	2157.1	3082.4	4179.4	5179.8	5833.3	6079.2	6396.0
Current Assets											
Cash	4.9	18.7	40.6	14.1	13.6	59.7	112.9	185.1	232.2	147.6	136.6
Accounts Receivable	.1		111.7	8.8	14.8	19.9	23.0	26.2	22.1	27.6	39.9
Inventory				25.3	25.3	25.3	25.3	25.3	25.3	145.6	145.6
Total Current Assets	5.0	18.7	152.3	48.2	53.7	104.9	161.2	236.6	279.6	320.8	322.1
Total Assets	749.0	1073.7	1110.7	1479.4	2210.8	3187.3	4340.6	5416.4	6112.9	6400.0	6718.1
Equity and Liabilities											
Equity											
Government Investment			295.6 1/	339.2	431.3	551.4	698.1	825.4	888.4	899.4	899.4
Retained Earning (Deficit)	11.6	27.8	(129.5)	(95.2)	(5.3)	132.1	296.6	487.3	639.6	697.5	673.7
Provision for Gratuity	.2	.3	.3	.4	.4	.5	.5	.6	.6	.7	.7
Revaluation Surplus				90.5	187.0	276.9	362.5	447.9	535.8	626.3	1066.3
Total Equity	11.8	28.1	166.4	334.9	613.4	960.9	1357.7	1761.2	2064.4	2223.9	2640.1
Long Term Debt											
Masinga	728.8 1/	1045.6 1/	944.3 1/	924.5	904.1	883.1	861.5	839.2	816.3	792.6	768.2
Kiambere				190.0	637.5	1270.2	2033.4	2735.8	3180.7	3365.3	3306.3
Total Long-Term Debt	728.8	1045.6	944.3	1114.5	1541.6	2153.3	2894.9	3575.0	3997.0	4157.9	4074.5
Current Liabilities											
Bank Overdraft	8.4										
Accounts Payable				30.0	55.8	73.1	88.0	80.2	51.5	18.2	3.5
Total Current Liabilities	8.4			30.0	55.8	73.1	88.0	80.2	51.5	18.2	3.5
Total Equity and Liabilities	749.0	1073.7	1110.7	1479.4	2210.8	3187.3	4340.6	5416.4	6112.9	6400.0	6718.1
Current Rates	.6			1.6	1.0	1.4	1.8	3.0	5.4	17.6	92.0
Debt Equity Ratio	98/2	97/3	85/15	77/23	72/28	69/31	68/32	67/33	66/34	65/35	61/39

1/ Prior to FY 1982 the Government's investment in the Masinga Project was classified in the accounts of TARDA as debt without interest or principal repayment requirements. In FY 1982 the Government determined that the investment should be classified as KSh 295.6 million equity grant and KSh 944.3 million debt repayable over 20 years at 3% interest.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

TANA AND ATHI RIVERS DEVELOPMENT AUTHORITY (TARDA)

FUND FLOW STATEMENT

For the years ending June 30, 1980/1990
(Million KSh)

	Actual		Provisional		Forecast							
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1983-89	1990
Internal Generation												
Net Income From Power			89.2	75.7	130.7	177.4	203.8	229.5	190.8	315.2	1323.1	398.3
Power Depreciation				20.1	23.4	25.6	27.8	29.9	32.2	34.6	193.6	138.9
Net Other Income (Loss)	7.8	16.2	(.9)	(13.2)	(15.2)	(17.2)	(19.3)	(21.6)	(24.2)	(27.1)	(137.8)	(30.3)
Other Depreciation	.7	.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	7.7	1.1
Provision for Gratuity		.1	-	.1	-	.1	-	.1	-	.1	.4	-
Gross Interest Generation	8.5	17.2	89.4	83.8	140.0	187.0	213.4	239.0	199.9	323.9	1387.0	508.0
Operating Requirements												
Debt Service				48.0	48.0	48.0	48.0	48.0	48.0	244.5	532.5	440.9
Distribution to Non-power Activities										50.0	50.0	50.0
Working Capital Increase (Decrease)	(9.4)	22.2	133.6	(134.1)	(20.3)	33.9	41.4	83.2	71.7	74.5	150.3	16.0
Total Operating Requirements	9.4	22.2	133.6	(86.1)	27.7	81.9	89.4	131.2	119.7	369.0	732.8	506.9
Net Available From Operations	17.9	(5.0)	(44.2)	169.9	112.3	105.1	124.0	107.8	80.2	(45.1)	654.2	1.1
Construction Requirements												
Masinga Power Station	255.8	311.4	107.0	60.0							60.0	
Kiambere Power Station			42.0	338.2	626.6	801.1	941.4	811.5	429.4	87.8	4036.0	
Interest During Construction				4.2	24.2	55.7	91.4	124.9	157.6	89.0	547.0	
Other	2.4	.5	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	7.7	1.1
Total Construction	258.2	311.9	150.1	403.5	651.9	857.9	1033.9	937.5	588.1	177.9	4650.7	1.1
Balance to Finance	240.3	316.9	194.3	233.6	539.6	752.8	909.9	829.7	507.9	223.0	3996.5	-
Financing												
Masinga Loan 1/	240.3	316.9	(101.3)									
Kiambere Loan				190.0	447.5	632.7	763.2	702.4	444.9	212.0	3392.7	
Government Equity Contribution 1/			295.6	43.6	92.1	120.1	146.7	127.3	63.0	11.0	603.8	
Total Financing	240.3	316.9	194.3	233.6	539.6	752.8	909.9	829.7	507.9	223.0	3996.5	
Debt Service Coverage	NA	NA	NA	1.7	2.9	3.9	4.4	5.0	4.2	1.2	2.5	1.1

1/ Prior to FY 1982 the Government's investment in the Masinga Project was classified in the accounts of TARDA as debt without interest or principal repayment requirements. In FY 1982 the Government determined that this investment should be classified as KSh 295.6 million equity and KSh 944.3 million debt repayable over 20 years at 3% interest.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Loan Capital and Security Arrangements of KP&L, KPC, TRDC and TARDA

1. This annex describes the loan capital of power companies of Kenya and the arrangements securing this loan capital. The amounts stated represent the total amount of the loans contracted and not the amounts outstanding, which are given in Annex 16. Unless indicated otherwise, all references to £ are references to £ Sterling.

KP&L

2. KP&L's loan capital comprises loans from Commonwealth Development Corporation (CDC), (KSh. 7 million, KSh. 58.88 million and KSh. 30 million), and from Glyn, Mills and Company syndicate (KSh. 57.75 million, KSh. 4.328 million, KSh. 59.59 million and KSh. 4.8 million). The CDC loan of £350,000 was secured by (i) KP&L's 8½% Debentures 1971-85; and (ii) a Trust Deed dated November 1, 1968, which provided for a first legal charge on specified leasehold properties of KP&L. The KSh. 58.88 million CDC loan and the KSh. 57.75 loan from the Glyn, Mills and Company syndicatewere respectively secured by Debenture Stock 1975-91 and 1971-80 respectively, as well as a Trust Deed dated May 16, 1969. This Trust Deed created mortgages and charges on certain of KP&L's properties and assets and also stipulated that KP&L was not to create any mortgage or charge ranking in priority to or pari passu with that mortgage or charge. The KSh. 30 million CDC loan and Glyn syndicate loans of KSh. 54.49 million and KSh. 4.8 million were secured by Debenture Stock 1979-88, and 1978-80 respectively, as well as a supplemental Trust Deed dated August 29, 1974 which made these loans to rank pari passu with the loans secured by the Trust Deed dated May 16, 1969. By the end of 1978 KP&L had also taken up KSh. 1.296 million at 8% on an unsecured basis from a KSh. 15 million given by the British Government to the Government of Kenya and a further KSh. 7.342 million on similar terms from a loan of KSh. 20 million made to the Government of Kenya by the Finnish Government.

KPC

3. In 1955 KPC floated a £7,500,000 loan by the issue of a £7,500,000 5½% Debenture Stock 1975/85. £3,500,000 of this loan was subscribed by CDC, and the balance was underwritten for public sale. The Debenture Stock was secured by a Trust Deed Dated June 27, 1956, which among other things, created a first legal charge and a floating charge in respect of KPC's property and assets and stipulated that KPC was not to create any further charges or incumbrances upon its undertakings and assets ranking in priority to or pari passu with the charges created under the Trust Deed except in special stated circumstances. The Trust Deed also provived that any scheme for the reconstruction should require an extraordinary three-fourths of the stockholders. KPC also took up in 1977 an unsecured

9% loan from KP&L, in the amount of KSh. 26.34 million, repayable in 10 years commencing from the commissioning of the first geothermal plant as well as KSh. 1.25 million of an 8.5% unsecured loan from TRDC totalling KSh. 2.9 million (balance taken up in 1978) and repayable from 1979 to the year 2000. Both of these loans were repaid in 1978. In 1980, KPC contracted with IBRD to borrow US$40 million at 7.95% annual interest and repayable during 1985-1999, and with CDC to borrow £9.25 million at 8.5% annual interest and repayable during 1982-1994 for installing the first two units of the Olkaria power project.

5. To finance the Olkaria Geothermal Power Expansion Project, KPC proposes to obtain a loan of US$12 million from IBRD, at a variable interest rate US$8.3 million from CDC at 8% interest and US$8.8 million from EIB at 8% interest.

TRDC

6. TRDC's loan capital in 1978 came from CDC, the Glyn, Mills and Company syndicate (now Williams & Glyn's Bank Ltd.), KP&L, IBRD, the Government of Kenya, from a SIDA credit to the Government of Kenya, and from the Standard Bank Limited and export suppliers credits. A Trust Deed dated May 26, 1966 modified and extended by three Supplemental Trust Deeds dated December 5, 1968, December 16, 1971 and March 10, 1976, secures the following loans:

b) Sh. 9,240,500 and Sh. 5,380,000 B Debenture Stock 1971-87;

c) Sh. 6,040,000 C Debenture Stock 1971-87;

d) Sh. 81,300,000 E Debenture Stock 1975-96;

e) US$23,000,000 and US$63,000,000 IBRD loans;

f) L2,000,000 Debenture Stock 1980-91;

g) KSh. 2,000,000 loan from KP&L; and

h) KSh. 1,890,000 loan from the Government of Kenya.

The Trust Deed provided for the creation of a floating charge of TRDC's undertakings, property and assets and also required TRDC (i) not to (A) create without the Trustee's consent any mortgage or charge ranking in priority to a pari passu with the floating charge of (B) create any specific mortgage or charge over any of its immovable property or other assets without prior written consent of the Trustee or have any subsidiary, except with the prior written consent of the Trustee. The Trust Deed also provides for the creation and issue in specified circumstances of additional stock to rank pari passu in point of security with the original stock created under the Trust Deed. These circumstances include the need to secure any loan TRDC would need to finance later stages of the Seven Forks Hydroelectric Project.

7. In addition, TRDC has issued promissory notes in the amounts of Dm 22,553,000 and US$217,000 to cover part of the export suppliers credits while DM 32,459,000 financed by Kreditanstalt fur Wiederaufbau is covered by a guarantee from the West German Government. The loan from the Standard Bank Limited was unsecured and repaid in 1978.

TARDA

8. TARDA's loan capital for the construction of the Masenga Hydrolectric Station came from the Government of Kenya. The Government provided KSh 944 million (US$75.5 million) at 3% interest to be paid in equal installments of principal and interest over a period of 20 years beginning July 1, 1982.

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KIAMBERE HYDROELECTRIC POWER PROJECT

Electricity Tariff Structure

1. KP&L's new tariff structure was developed in consultation with the Bank. It took effect on January 1, 1979 and comprises the following six categories:

Method A: covers consumers whose monthly usage does not exceed 7,000 KWh.

Method B: is applicable to consumers with monthly usage ranging from 7,001 to 100,000 KWh.

Method C: covers consumers whose monthly usage exceeds 100,000 units.

Method D: Off-peak supplies.

Method E: Public Lighting.

Method F: Company staff.

2. In addition, there is provision for the introduction of a fuel oil cost adjustment with the approval of the Ministry of Power and Communications. This is a surcharge designed to allow KP&L to recover part of any additional fuel costs from electricity consumers based on the difference between actual fuel cost and a "basic price". KP&L has added surcharge at rates of 13.9 Kenya cents per KWh from August 1980 and 21.2 cents from July 1981 on all energy sales.

3. Details of the tariffs are presented in the table on page 2 of this annex.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Electricity Tariff Structure

		Charge per kWh (Based on monthly consumption	Fixed charge per month	Demand charge per KVA per month	Projected Average Revenue per kWh in 1982
Method A	Monthly Consumption not exceeding 7,000 kWh	0 to 30 kWh : KSh 0.22 Over 30 kWh : KSh 0.50	KSh 15 a/		KSh 0.515
Method B	Monthly consumption ranging from 7,001 to 100,000 kWh	415/240 V : KSh 0.27/kWh 11kv/33 kv : KSh 0.25/kWh 66kv/132kv : KSh 0.23/kWh	415/240 V : KSh 60 11kv/33kv : KSh 360 66kv/132kv : KSh 1,640	415/240 V : KSh 50 11kv/33kv : KSh 45 66kv/132kv : KSh 40	KSh 0.462
Method C	Monthly Consumption in excess of 100,000 kWh	Peak Hours (8 AM to 10 PM, Mon-Fri) 415/240 v : KSh 0.27 11kv/33kv : KSh 0.25 66kv/132kv : KSh 0.23	415/240 V : KSh 60 11kv/33kv : KSh 360 66kv/132kv : KSh 1,640	415/240 V : KSh 50 11kv/33kv : KSh 45 66kv/132kv : KSh 40	KSh 0.311
		Off-peak Hours 415/240 V : KSh 0.16/kWh 11kv/33kv : KSh 0.15/kWh 66v/132kv : KSh 0.14/kWh			
Method D	Off-Peak supplies	KSh 01.6/kWh	KSh 32.50 a/		KSh 0.217
Method E	Public Lighting b/	KSh 0.45/kWh	KSh 32.50 per supply terminal		KSh 0.481
Method F	Company Staff	KSh 0.15/kWh			KSh 0.218

a/ If Method A is used in conjunction with Method D at the same supply terminals, the combined fixed charge will be KSh 35.
b/ Supplies available for a minimum period of 11 hours per night for public lamps.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

History of the Power Companies

1. The Kenya Electric Supply Industry is presently comprised of four organizations:

a) The Kenya Power & Lighting Co. Ltd (KP&L);

b) The Kenya Power Co. Ltd (KPC);

c) Tana River Development Co. Ltd (TRDC); and

d) Tana and Athi Rivers Development Authority (TARDA)

The Kenya Power & Lighting Co. Ltd (KP&L)

2. KP&L, which is the sole distribution company, was incorporated in 1922 by the amalgamation of two undertakings which had supplied Nairobi and Mombasa since 1907 and 1909, respectively. It is a local private company with authorised share capital of KSh. 250 million, of which KSh. 207.85 million is issued. In addition, loan capital amounting to KSh. 359.03 million was outstanding as at the end of 1981. Although formerly operating throughout Kenya, Uganda and Tanzania, its activities have been confined to Kenya since 1964 due to purchase of the Uganda and Tanzania undertakings by the respective Governments. The company is primarily concerned with the commercial distribution of electricity throughout Kenya. At present, it also generates the entire power requirements of the coast system covering Mombasa, Malindi and Kwale, provides the necessary thermal back-up for the main grid system, and operates generating stations in centers not connected to the grid. It also coordinates all sources of power, and staffs and manages KPC and TRDC, and since August 1981, staffs and manages the Masinga Dam powerhouse.

3. In 1970, the Government acquired a controlling interest in KP&L when it made a successful bid for all the shares on the London Register. Since then the Government has been purchasing shares as they come on the East African market, and its total holding together with that of government-controlled agencies is about 57%.

The Kenya Power Co. Ltd (KPC)

4. In 1955, KP&L was faced with the problem of financing the construction of a 132-kV transmission line to interconnect the power systems of Uganda and Kenya as well as other expansion requirements. The company did not consider it practicable to raise the required finances through new equity issues because of conservative dividend policies due to political pressures and the need for increased self-financing. There was also revived political pressure for nationalization. The company concluded it was inevitable and desirable to increase public ownership and direct

government participation in the power industry. Accordingly, it was decided to form a new company, KPC, in 1955 with an issued nominal capital of KSh. 2000 held equally by KP&L, the Government and a UK finance house. KPC's function was to construct the transmission line and to take over the ownership of the two hydroelectric stations belonging to KP&L on the Tana River. KPC financed its requirements through issuance of KSh. 7.5 million of debenture stock, the payment of the debt service on which was guaranteed by KP&L's understanding to purchase KPC's entire production at "ascertained cost".

5. In accordance with its policy of increasing its participation in the electricity supply industry, the Government acquired 100% of KPC's issued share capital by buying out KP&L's and Power Securities Corporation Ltd. in 1971. Subsequently, in 1980, KPC increased its share capital to KSh. 60 million and contracted IBRD and CDC loans of US$40 million and £ 9.25 million respectively to finance construction of the first two 15-MW units of the Olkaria Geothermal Power Project.

Tana River Development Co. LTD (TRDC)

6. A forecast of load growth after Kenya's achievement of independence in December 1963 indicated that it would be necessary to commission further major generating capacity by 1967-68, and a reappraisal of the Seven Forks Scheme (the harnessing of the hydropotential of the Upper Tana) established Kindaruma as the most economical first stage development. TRDC was formed in 1964 to finance the Kindaruma hydroelectric development for much the same reasons as led to the formation of KPC. The share capital of TRDC is KSh. 120 million, all of which is held by the Government. CDC supplied KSh. 3.5 million of a total of about KSh. 6 million of loan capital which was arranged for the Kindaruma project. Kamburu Stage 1, comprising the first two generating units, was commissioned in July 1974 and the third unit in 1976. Gitaru, the last of the Seven Forks hydroelectric projects, was commissioned in 1978. Like KPC, TRDC sells its entire output to KP&L at ascertained cost.

Tana and Athi Rivers Development Authority (TARDA)

7. The fourth company, Tana and Athi Rivers Development Authority, has constructed the Masinga Dam on the Tana River primarily for irrigation purposes. Advantage of the dam has been taken by KP&L to complete arrangements with TARDA to include a powerhouse and related structures and equipment at the site. KP&L pays a fixed charge of KSh. 49.7 million per year to TARDA from the date the reservoir was first filled to the maximum operating level and a usage charge of .32 per GWh. This charge has been adjusted in relation to the cost of fuel that this powerhouse displaces at the time of commissioning. All costs in excess of KSh. 4.9 for operation and maintenance of the powerhouse and other direct power-producing facilities, not including the dam, will be paid by TARDA.

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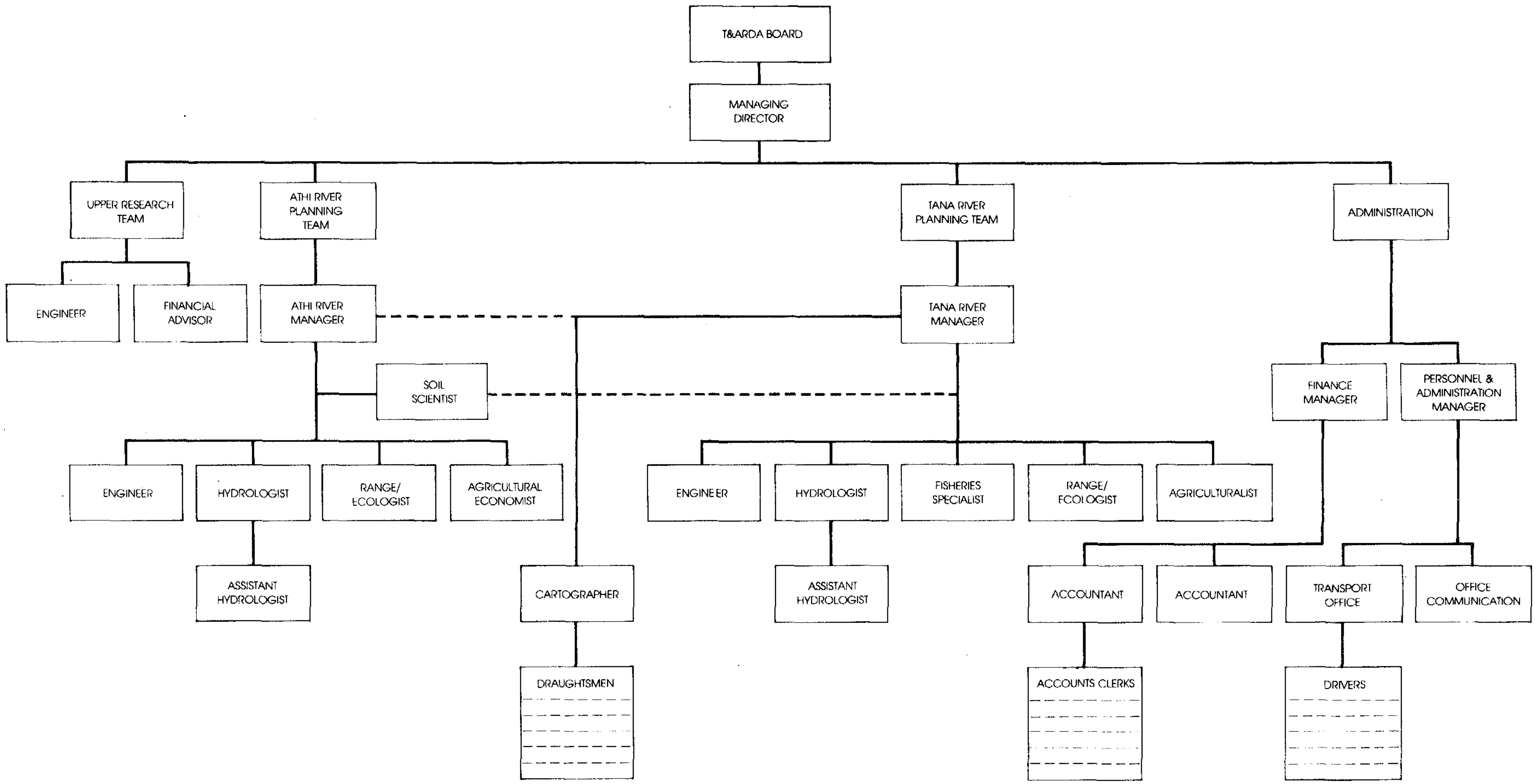
KIAMBERE HYDROELECTRIC POWER PROJECT
Tana and Athi Rivers Development Authority
Organization Chart



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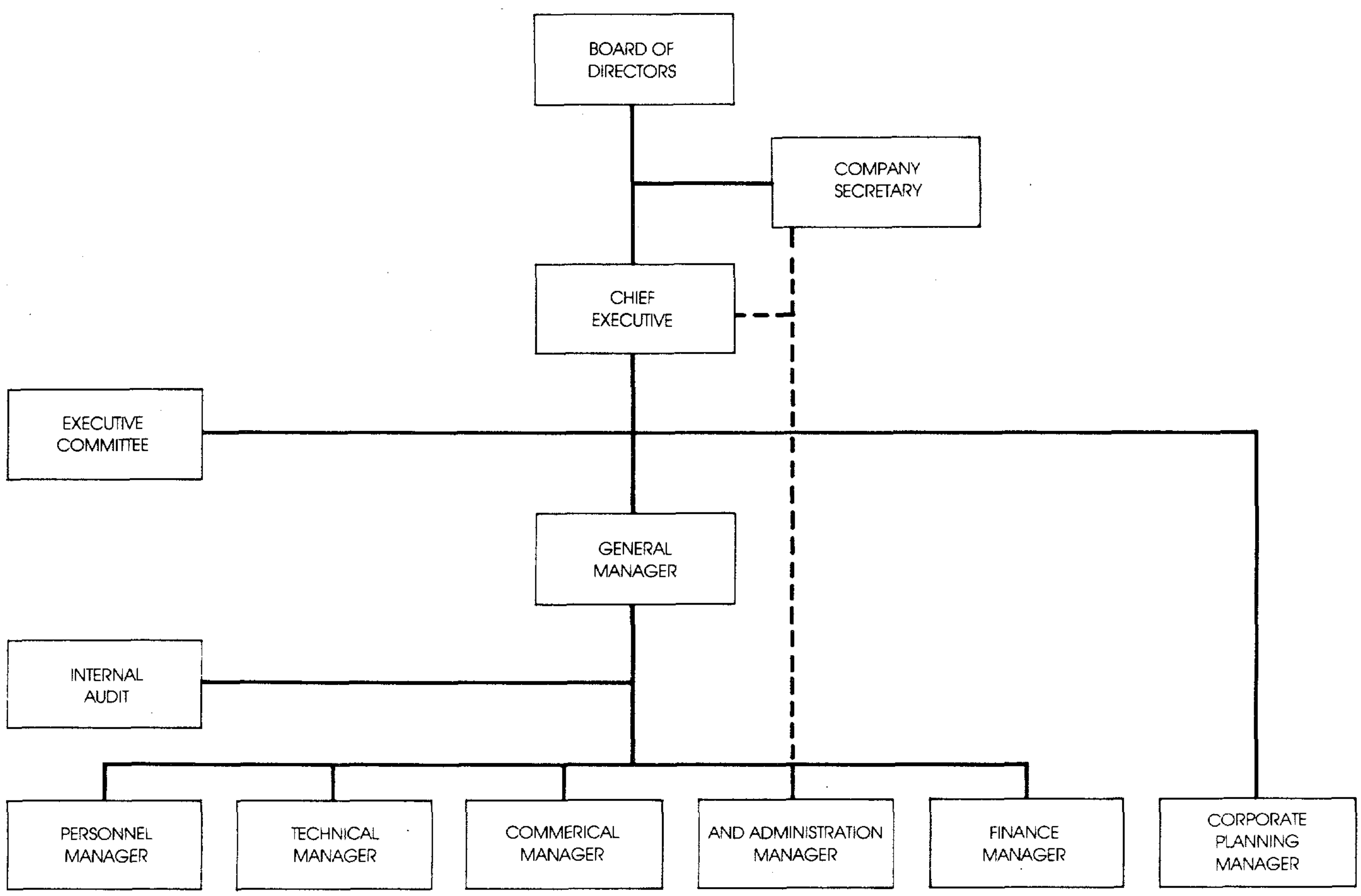
KIAMBERE HYDROELECTRIC POWER PROJECT
Kenya Power and Lighting Company Ltd.
Organization Chart



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KIAMBERE HYDROELECTRIC POWER PROJECT

Project Monitoring Guidelines

1. There are a number of areas described in the various chapters, which are key elements in the efficient operation of the utility and in the success of the project. The main areas for establishing a monitoring system are described below.

2. The principal implementation steps to be compared monthly with planned target dates are as follows:

A. Construction of Civil Works

Preparation of bid documents	October 1982
Invitation to bid	February 1983
Bid closing	May 1983
Contract Audits	September 1983
Construction starts	December 1983
Completion of the Dams	June 1987
Completion of Headrace Tunnnel	August 1987
Completion of Tailrace Tunnel	August 1987
Completion of Powerhouse	May 1987

B. Electrical and Mechanical Works

Preparation of design	June 1982
Preparation of bid documents	October 1982
Invitation to bid	January 1983
Contract awards	September 1983
Manufacturing start	November 1983
Commissioning of Unit No. 1	February 1988
Commissioning of Unit No. 2	June 1988

C. Organization Study

Appointment of consultants	May 1984
Completion of the study	December 1984

3. Records will be maintained comprising the targets against actual results in:

General:

(a) Hydro production (in kWh);
(b) Diesel station production (in kWh);
(c) Purchase from captive plants (in kWh);
(d) Purchase from Uganda (in kWh and maximum demand in MW)
(e) Power consumption (in kWh, by classification);
(f) Consumption of station auxiliaries (in kWh);

(g) Specific fuel consumption of diesel stations (in kCal/kWh and gr/kWh);
(h) Losses (by classification);
(i) Equipment and transmission line failures;
(j) Number of interruptions and their durations together with their reasons;
(k) Number of consumers (by classification).

Administrative and Financial

(l) Number of staff (by classification);
(m) Average tariff level (in cents per kWh and by classification);
(n) debt service coverage
(o) Operation ratio;
(p) Number of days' sales outstanding;
(q) Debt/equity ratio;
(r) Revision to project cost estimate and related financing;
(s) Overdue accounts receivable.

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KIAMBERE HYDROELECTRIC POWER PROJECT

Future Sales and Maximum Demand

Introduction

1. KP&L, in accordance with sound engineering practices, regularly revises the load forecast for the preparation of the next month's budget and the yearly forecast for the next year's budget. At the time of the appraisal mission KP&L's revised load forecast was reviewed by using a direct forecasting method and based on KP&L's consultants' load forecasts prepared (by Merz and McLellan) in 1978, by WLPU and EP in 1981. This load forecast was rechecked by the mission's consultant by using a comprehensive statistical method. These two load forecasts gave almost the same results, an average growth rate of 6% p.a. between 1982 and 1990, for annual growth and consumptions of various consumer groups for future years. Therefore, the mission concluded that load forecasts are realistic and should be accepted for the timing of the future generation projects and used for the economic analysis. The analyses of the mission's consultant are given in the following paragraphs.

Geographical Distribution

2. Historical growth and market composition figures for the power and energy demand for the interconnected network are presented in Table 1 of this annex. Historical trends indicate that sales in the Nairobi District as a percentage of total sales have declined slightly from about 60% in 1984-1975 to a present level of 56% while sales in the Western District have increased from about 8% to 11% of total. This change in relative importance of market areas reflects the government's policy since the early 1970's to stimulate development (particularly industrial) in the Western region. It is now expected that over the next ten years the percentage of total sales in each area will remain constant at the current level.

Consumption by Consumer Category

3. KP&L has broadly grouped the various tariff categories as shown in Table 1 of this annex, thereby permitting an analysis of market composition by major consumer categories. The increased percentage of large commercial and industrial sales from 56% in 1974 to 64% in 1982 reflects the rapid industrial growth as a result of Government policy and the strong economic growth which occurred during the coffee boom of 1976-1978. Interruptible sales (such as for water heating) declined slightly in absolute terms from 134 GWh in 1975 to 118 GWh in 1981. This decline is the result of increasing tariffs for this category and the promotion of solar water heaters as a substitute for electrical water heating.

Statistical Analysis

4. A statistical analysis for the correlations between growth in sales for the two major categories, (a) domestic and small commercial, and (b) industrial and large commercial and growth in overall gross domestic product (GDP), and manufacturing sector growth rates respectively was carried out. A high correlation, at greater than 95% confidence level, was found. The data were smoothed in order to reduce the impact of random events before carrying out a regression analysis to establish the functional relationships between power sales and economic growth. Trended growth rates for power sales and economic growth were computed on a five year basis moving forward until the data were exhausted. A linear regression analysis was then carried out on the smoothed data and the following functional relationships determined:

(a) domestic and small commercial power sales annual percent growth rate = 2.8% + 1.1 (GDP annual percent growth rate);

(b) industrial and large commercial power sales annual percent growth rate = 3.4% + 0.7 (manufacturing sector annual percent growth rate).

6. Power sales forecasts for categories (a) and (b) above were derived using the functional relationships and on the basis of the Bank's recent estimates of economic growth rates in Kenya to 1990:

GDP	1982-1985	1986-1990
	-----Annual Growth %-----	
Overall GDP	3.5-4.0	4.0-5.0
Manufacturing Sector	1.5-3.0	4.0-5.0

6. In addition to consumption forecasts for the two basic categories prepared using these relationships, individual forecasts were made for off-peak sales (interruptible supplies for domestic water heating and irrigation pumping), and street lighting. The forecast of industrial sales was then adjusted to take into account specific new industrial loads which are linked to projects either under construction or with a high probability of realization. The overall forecast prepared as described above compared closely with the forecast prepared by KP&L using a 6% overall growth rate and this growth rate was retained for planning purposes. Details of the demand forecast as discussed and agreed with KP&L are given on page 4 of this annex.

KP&L HISTORICAL POWER SALES

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Est. 1982
Power Sales (GWh)												
Domestic/Small Commercial					294	302	339	360	385	402	438	463
Large Commercial/Industrial					562	639	742	814	891	944	1026	1066
Off Peak					134	130	111	117	123	111	118	120
Street Lights					11	11	11	10	10	11	11	11
Total	715	795	860	925	1001	1082	1203	1301	1409	1468 1/	1593	1660
Annual Growth %	10.7	11.2	8.2	7.6	8.2	8.1	11.2	8.1	8.4	4.2 2/	8.5 2/	4.2
Percentage Each Area of Total Sales												
Nairobi				61.1	60.1	58.9	56.9	56.3	56.1	56.3	56.5	n.a.
Coast				24.2	23.8	24.8	25.o	25.4	24.4	24.3	24.5	n.a.
Western				7.5	8.5	8.2	9.6	10.3	11.9	11.7	11.3	n.a.
Rift				4.8	5.1	5.5	5.2	5.4	5.0	4.9	5.0	n.a.
Mount Kenya				2.5	2.5	2.7	3.2	2.6	2.6	2.7	2.8	n.a.
Percentage of Total by Category												
Domestic/Small Commercial				29.4	27.9	28.2	27.7	27.3	27.4	27.4	27.5	27.9
Large Commercial/Industrial				56.1	59.1	61.7	62.6	63.2	64.3	64.3	64.4	64.2
Off Peak				13.4	12.0	9.2	9.0	8.7	7.6	7.6	7.4	7.2
Street lights				1.0	1.1	0.9	0.8	0.7	0.8	0.8	0.7	0.7

1/ Sales constrained by water shortage and thermal plant outage. Unconstrained demand estimated at 1521 GWh.

2/ On basis of unconstrained sales in 1980 at 1521 GWh, growth rates in 1980 and 1981 would have been 8.0% and 4.7% respectively.

KENYA INTERCONNECTED POWER SYSTEM DEMAND FORECAST

	Estimated	Forecast							
	1982	1983	1984	1985	1986	1987	1988	1989	1990
Power Sales (GWh)									
Domestic/Small Commercial	463	496	532	569	608	650	706	759	816
Large Commercial/Industrial	1066	1113	1186	1266	1353	1439	1517	1605	1696
Off Peak	120	120	120	120	120	120	120	120	120
Street Lights	11	11	11	12	12	12	12	12	12
Total	1660	1760	1865	1977	2096	2221	2355	2496	2645
Growth %		6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Total Generation Required (GWh) 1/	1953	2071	2194	2326	2466	2613	2771	2936	3112
System Maximum Demand - MW 2/	328	348	368	390	414	439	465	493	522

1/ Assuming 15% generation losses in station uses, transmission, and distribution.

2/ Assuming 68% system annual load factor.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Economic Analysis - Least Cost Solution

Generation Development Options

1. The timing of additional new generating facilities has been established on the basis of the forecast demand growth rate of 6% p.a. (Annex 20, p. 4), the capacity of existing facilities, and the earliest feasible on-line dates of new plants. Details of existing generating capacity are given in Annex 1, page 2.

2. Additional energy requirement could be satisfied by:

(a) further development of Kenya's hydro and geothermal potential;

(b) the construction of thermal plants using imported fossil fuels; or

(c) interconnection with Tanzania and/or Uganda.

There are many power generation project possibilities in the above classification. Feasible development alternatives to satisfy load growth to 1995 have been determined from these generation options as presented below.

3. Indigenous hydro resources: Mainly two alternative hydro schemes are available to be taken into consideration at this time; these are the Kiambere and Turkwel projects as shown below:

	Kiambere a/	Turkwel b/
Installed Capacity (MW)	2x70	2x60
Firm Energy (GWh/year)	683	430
Average Energy (GWh/year)	910	460
Plant Factor %	74	44
Earliest on-line date	January 1988	Mid 1990
Capital cost (KSh million) c/	2,448	1,859

a/ Kiambere Final Engineering Report, WLPU, Sept. 1984 and project cost estimates following bid evaluation.

b/ Turkwel Feasibility Study, Norconsult, 1979. Revised cost estimate SOGREAH, 1982.

c/ Base cost plus physical contingencies , mid 1983 prices; local labour (15% of total cost) shadow priced at 50%.

An initial feasibility study for Turkwel was prepared in 1979 by Norconsult. Additional engineering and hydrological work was carried out by SOGREAH and their report prepared in 1982 covered the initial field investigations, hydrological data and preliminary design. It is estimated that the earliest on-line date is 1990.

4. Other Hydro Possibilities:

Other hydro possibilities include:

Site	Installed Capacity MW	Average Generation GWh/year	kW installed cost (US$)
Mutonga	70	410	4510
Grand Falls	80	480	3500
Adamson's Falls	50	300	8360
Koreh	80	400	6930
Sondu	60	340	4510

Source: The 1979-2000 Development Plan.

These plants have a higher unit cost than either Kiambere or Turkwel and could not be built before the mid 1990s since no reliable data and suitable study is available.

5. Geothermal: The third Olkaria unit (15 MW and 100 GWh/yr) financed by the Bank will come on-line in 1985. Additional units can be constructed at Olkaria, however, the next three 15 MW units could not be available before mid 1989. In 1989, the new units could be expected to produce about 70 GWh due to availability for no more than six months and less than normal output during the commissioning period. Since experience with geothermal operation in Kenya is brief, the availability of units 4, 5 and 6 and, hence, their firm energy capability has been assumed to increase to 65% by 1992 and remain constant thereafter. Capital costs for development of the next units at Olkaria are assumed to be the same as for the first three Olkaria units and, allowing 20% contingencies, the estimated cost is KSh 2318 million (US$185 million) 1/ for 3x15 MW units including transmission. O & M costs of KSh 33 million per year include provision for drilling 2 new wells each year.

6. Thermal Plants Based on Imported Fuel: WLPU consultants with Ewbank and Partners have examined a coal-fired and an oil-fired thermal alternative to Kiambere. Since no detailed studies of either alternative are available, it is estimated that 1989 is the earliest on-line date. Data used in the economic calculations relative to these alternatives are shown below. WLPU/EP demonstrated that a coal-fired plant was cheaper than oil-fired up to 12% discount rate. Considering that coal costs could be as low as $50/ton, only the coal option was retained for this analysis.

1/ mid 1983 prices, excluding IDC, taxes and duties.

	Coal-fired	Oil-fired
Installed capacity (MW)	2x60	2x60
Capital cost (US$ mln) a/	224	163
Fuel cost (US$/tonne)	70	180
Fuel Rate (kg/kWh)	0.49	0.27
Operation and Maintenance costs (UScents/kWh)	0.85	0.58
Cost per kW installed	1,867	1,358
Annual generation capability (GWh)	720	780

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a/ mid 1983 prices, excluding IDC, taxes and duties.

7. Gas Turbines: The installation of gas turbines would provide firm energy in a dry year and would permit the operation of the Masinga reservoir to maximize average energy output of the Tana cascade plants. Without the 30 MW gas turbine planned by KP&L in 1985, Masinga reservoir should be operated to maximize firm energy with a resultant reduction in the expected average annual generation from the Tana cascade plants (requiring an increase in thermal generation of about 50 GWh/yr). The firm energy capability would be reduced by about 130 GWh/year with a risk of an energy deficit by 1986 unless the gas turbine is added. Additional gas turbines were also examined as a means of deferring high capital cost plants such as Kiambere or Turkwel and as a means of firming up hydro energy prior to the availability of geothermal or coal-fired plant in 1989. Their use other than for peaking and standby would be very costly and any economic advantage in deferring other plant additions would be quickly lost.

8. The cost of generation by gas turbines is estimated as follows:

- Capital cost/kW	US$605
- Operation and maintenance costs	7% of capital a/
- Fuel cost (kerosene)	$396/ton
- Fuel rate	311 gms/kWh
- Availability	50%

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a/ Including fuel for weekly operation to ensure availability.

9. Diesel Plant: Additions of diesel plant were also considered to firm up hydro energy in a dry year or to defer the addition of new hydro plants in the event of capacity constraints. As with gas turbines, their use for base load generation would be expensive. Given the small unit sizes (compared with load growth requirements) deferment of a large hydro

or thermal plant would be minimal. The use of diesels as a substitute for gas turbines (which have a lower cost per kW of capacity than diesels) or for large thermal or hydro plants (with lower energy cost at high load factor) has therefore not been further considered.

10. Interconnection with Neighboring Countries: The possibility of importing power from either Tanzania or Uganda exists since large amounts of relatively low cost hydro energy could be developed in those countries. It is unlikely that Uganda would be able to increase its supply to Kenya beyond the present level of 250 GWh/yr (existing 30 MW contract running to 2005) before 1990. Kenya would then require major additions in thermal capacity as a stop-gap measure prior to the availability of increased power from Uganda. The political climate would also need to improve before interconnection between Kenya and Tanzania would be a realistic alternative to Kiambere. There is however a good possibility that imported power would be the least cost solution to meet load growth following the achievement of Kiambere capacity; however, due to the uncertainties involved, imported power has not been further considered in this analysis. Furthermore, in keeping with Government objectives to ensure maximum national independence in energy sources and since availability of the existing UEB supply cannot be fully guaranteed, it is assumed, in determining the power and energy balances (para. 12) that the UEB supply would not be firm beyond 1987. Use of UEB imports would, however, continue as a means of regulating reservoir levels and displacing thermal generaration.

11. Alternative Generation Development Programs: The timing of new plant additions has been established as required to meet constraints either in firm energy or firm power based on 6% p.a. load growth. The following alternative development strategies which provide the same security of supply without possible load shedding as a means of delaying plant additions were reviewed by the appraisal mission to determine the least cost solution to 1994. Several other alternatives (essentially minor variations of those shown) were also examined but were quickly eliminated as they were evidently more costly in present value terms for discount rates up to 12%. It is assumed in the following analysis that the 30 MW gas turbine would be added in 1985.

Alternative A: develop hydro first - Kenya's present development program

Gas Turbine 1985	(1x30 MW)
Kiambere 1988	(2x70 MW)
Turkwel 1990	(2x60 MW)
Geothermal 1992	(3x15 MW)

Alternative B: develop coal first followed by hydro

Gas turbine 1985	(1x30 MW)
Gas turbines 1988	(3x25 MW)
Coal Plant 1989	(2x60 MW)
Kiambere 1992	(2x70 MW)

Alternative C: delay hydro with gas turbines and geothermal

Gas turbine 1985	(1x30 MW)
Gas turbines 1988	(3x25 MW)
Gas turbines 1989	(35 MW)
Geothermal 1989	(3x15 MW)
Kiambere 1992	(2x70 MW)
Turkwel 1994	(2x60 MW)

12. Power and Energy Balance: Transmission, distribution, and generating station losses totaling 15% have been added to the energy sales forecast to give the total generation requirement for each year. The system maximum power demand has been derived based on the expectation that the overall annual system load factor will remain at its present level of 0.68. A summary of energy generation and power capacity requirements are shown on pages 8, 9 and 10 of this annex as are the capacities of existing facilities and possible additional plant to be added in each alternative. A year by year balance for alternative A is presented on pages 11 and 12. Complete details of the power and energy balances for B and C are found in the project file.

13. The hydro plants on the Tana River system (the Tana cascade) comprising Masinga, Kamburu, Gitaru, Kindaruma, and the proposed Kiambere project would be capable of producing an average annual energy of up to 2,910 GWh based on KP&L estimates using a system simulation model 2/ and the available hydrological record since 1947. Due to storage limitations and fluctuations of seasonal flows, the usable average annual energy at present from the Tana cascade as shown by the simulation model at the present demand level (excluding Kiambere) is 1,430 GWh and will grow to its maximum of 2000 GWh when the annual generation requirement rises to about 6,700 GWh. Average annual hydro generation depends on the availability of non-hydro energy sources (geothermal, other thermal and UEB imports) as well as total system demand. Generation by each type of plant has been estimated by KP&L on the assumption that geothermal sources and UEB supply would be used to their maximum followed by available hydro with the balance provided by thermal plant. Estimates of hydro generation for this analysis were based on interpolations of available data.

14. The firm energy capability of existing facilities is based on the assumptions of thermal plant availability discused above and the hydrological record for the hydro plants. Imports from UEB are assumed to continue at the present level of 30 MW firm power and 252 GWh/yr until 1987. From 1988 onwards, it is assumed that 252 GWh/yr would still be available from UEB but the power or energy would not be firm.

2/ The Tana River Simulation Model was developed by Merz & McLellan (1978) and extended by WLPU to include Kiambere.

15. Reserve capacity margins equivalent to the largest thermal unit (30 MW at Kipevu) and the largest hydro unit (75 MW at Gitaru) have been assumed in deriving the power balance. This level of reserve capacity is reasonable.

Economic Analysis of Alternatives

16. Alternative A is capable of meeting load growth to end 1993, while B and C can meet growth to 1995 and 1996 respectively before new additions would be required. As sufficiently reliable details of further plant additions are not available to extend the period of load growth to a point that equal capacities and firm energy capability under each alternative could be reached, a simplifying assumption has been made in the discounted cash flow analysis of the three cases. Alternatives B and C would be comparable with Alternative A by assuming that the firm energy constraint would be reached by 1994 (as in Alternative A) and additional plant would then be required. Since the energy constraint in Alternatives B and C would not be reached until 1995 and 1996 respectively, it has been necessary to make the three Alternatives comparable in 1994 by allowing for the residual value of the gas turbines installed in 1988 and 1989 in Alternatives B and C. Assuming a 15 year useful life for the gas turbines, a residual value for the remaining life of each unit has been credited in the cashflows in 1994 in Alternative B and C.

17. The cashflow streams for the three Alternatives are shown in Table 6 based on the foregoing considerations and the estimates of incremental capital and operating costs of each new plant added. Costs which are comparable to each alternative, notably the 30 MW gas turbine in 1985, have been omitted from the cashflow streams. Incremental fuel costs in Alternatives B and C (versus Alternative A) have been estimated according to available information concerning thermal generation with and without Kiambere. The present values of cost of each alternative at discount rates 10-28% are shown graphically on page 14 of this annex.

Discounted Cashflow Results

18. The equalizing discount rates for the three base case alternatives are as follows:

Alternative A is cheaper than B and C for discount rates up to 22.5% and 24.0% respectively.

Alternative C is cheaper than B up to 21.5% discount rate.

Sensitivity

19. If total costs for Kiambere increase by 10%,

Alternative A is cheaper than B up to 21.0%
Alternative A is cheaper than C up to 21.5%
Alternative C is cheaper than B up to 20.5%.

If coal costs are $50/ton while project costs increase by 10%,

A is cheaper than B up to 18.5%
C is cheaper than B up to 17.0%.

Conclusion

20. The foregoing comparison of the alternatives demonstrates that the sequence beginning with Kiambere as the next major plant would be the least cost solution. The decision by KP&L to take the risk of an energy deficit with the possible need for load shedding in 1987 by foregoing the installation of the 30 MW gas turbines in 1985 does not materially affect the results of the analysis. In each alternative the timing of plant additions after 1988 should be advanced where possible (i.e. Kiambere and Turkwel) to ensure system reliability, or continued risks of energy deficits would occur in 1988 since the coal-fired thermal and geothermal plants could not be advanced in Alternative B or C respectively. The present value of costs of each alternative would increase by advancing plant additions; however, the equalizing discount rate would not change significantly.

21. The power and energy balances for the case without the 30 MW gas turbine in 1985 and without changing the timing of new plant additions are shown on pages 8 to 12.

Power and Energy Balances for years which Generation Additions Planned - Alternative A

	1984	1985	1988	1990	1992	1993
System Max Demand (MW)	368	390	465	522	587	622
Available capacity (cumulative) a/	497	497	481	599	719	764
Plant additions	-	15 b/	140 c/	120 d/	45 e/	-
Total available	497	512	621	719	764	764
less reserve	105	105	105	105	105	105
Surplus (deficit) reserve	24	17	51	91	72	36
Generation required (GWh)	2194	2326	2771	3112	3498	3708
Firm energy capability (cumulative)	2465	2465	2313	2881	3311	3536
Plant additions	-	80 b/	683 c/	430 d/	225 f/	35 g/
Total firm energy	2465	2545	2996	3311	3536	3571
Surplus (deficit) firm energy	271	219	225	199	38	(137)

a/ After retirements and derating of existing capacity and assuming Uganda supply not firm after 1987 and 30 MW gas turbine not built in 1985.

b/ 3rd Olkaria 15 MW geothermal.

c/ Kiambere.

d/ Turkwel.

e/ Olkaria geothermal units 4, 5 and 6.

f/ Initial first year availability.

g/ Increase to 65% availability.

Alternative B - Power and Energy Balance

	1984	1985	1988	1989	1992	1995
System Maximum Demand (MW)	368	390	465	493	587	699
Available capacity (cumulative)a/	497	497	480	542	654	794
Plant additions	-	15 b/	75 c/	120 d/	140 e/	-
Total available	497	512	556	662	794	794
less reserve	105	105	105	105	105	105
Surplus (deficit) reserve	24	17	(8)	64	102	(10)
Generation required (GWh)a/	2194	2326	2771	2936	3498	4166
Firm energy capability (cumulative)	2465	2465	2314	2583	3248	3931
Plant additions	-	80b/	329c/	720d/	683e/	-
Surplus (deficit) firm energy	271	219	(128)	366	433	(235)

a/ After retirements and derating of existing capacity and assuming Uganda supply not firm after 1987 and 30 MW gas turbine in 1985 not built.

b/ 3rd Olkaria 15 MW geothermal.

c/ Gas turbines 3x25 MW.

d/ Coal steam plant 2x60 MW.

e/ Kiambere.

Alternative C - Power and Energy Balance

	1984	1985	1988	1989	1990	1994
System Maximum Demand (MW)	368	390	465	493	522	660
Available capacity (cumulative)[a]	497	497	481	542	614	754
Plant additions	-	15	75	80	140	120
Total available	497	512	556	622	754	874
less reserve	105	105	105	105	105	105
Surplus (deficit) reserve	24	17	(14)	24	126	109
Generation required (GWh)	2194	2326	2771	2936	3112	3930
Firm energy capability (cumulative)[a]	2465	2465	2313	2582	2880	3624
Plant additions	-	80 [b]	322 [c]	223 [d]	683 [e]	430
Surplus (deficit) firm energy	271	351	(129)	(131)	451	124

a/ After retirements and deratings of existing capacity and assuming Uganda supply not firm after 1987. Also allows for increase in annual availability of Olkaria units 4, 5 and 6. 30 MW gas turbine in 1985 excluded.

b/ 3rd Olkaria 15 MW geothermal

c/ 3x25 MW gas turbines

d/ 35 MW gas turbine plus Olkaria geothermal units 4, 5 and 6 mid 1989 providing 70 GWh firm. Geothermal availability increases to 65% (260 GWh firm energy) by 1992.

e/ Kiambere

f/ Turkwel

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Kiambere Hydroelectric Power Project

Power Balance - Alternative A

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SYSTEM MAX DEMAND (MW)	348	468	390	414	439	465	493	522	554	587	622	660	699
START YEAR FIRM CAPACITY													
HYDRO	319	319	319	319	319	319	459	459	579	579	579	579	579
THERMAL	86	86	86	86	86	86	86	78	78	78	78	78	78
DIESEL	15	15	15	14	14	14	0	0	0	0	0	0	0
GAS TURBINES	17	17	17	17	17	17	17	17	17	17	17	17	17
GEOTHERMAL	30	30	30	45	45	45	45	45	45	45	90	90	90
TOTAL	467	467	467	481	481	481	607	599	719	719	764	764	764
RETIREMENTS													
THERMAL							8						
DIESEL			1			14							
PLANT ADDITIONS													
GEOTHERMAL			15							45			
KIAMBERE						140							
TURKWEL								120					
IMPORTS	30	30	30	30	30								
CAPACITY TO MEET PEAK	497	497	511	511	511	621	607	719	719	764	764	764	764
RESERVE REQUIRED	105	105	105	105	105	105	105	105	105	105	105	105	105
SURPLUS/DEFICIT RESERVE	44	24	47	-8	-33	51	9	92	60	72	37	-1	-40
AVAIL RESERVE % OF MAX DEM	43	35	39	23	16	33	23	38	30	30	23	16	9

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Kiambere Hydroelectric Power Project

Power Balance - Alternative B

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SALES (GWH)	1760	1865	1977	2096	2221	2355	2496	2645	2805	2973	3151	3340	3541
TOTAL LOSSES %	15	15	15	15	15	15	15	15	15	15	15	15	15
GENERATION REQUIRED (GWH)	2071	2194	2326	2466	2613	2771	2936	3112	3300	3498	3708	3930	4166
ENERGY CAPABILITY (GWH)													
FIRM HYDRO (DRY YEAR)	1317	1317	1317	1317	1317	2000	2000	2430	2430	2430	2430	2430	2430
THERMAL	570	570	570	570	570	570	570	515	515	515	515	515	515
DIESEL	60	60	60	60	60	60							
GAS TURBINE	66	66	66	66	66	66	66	66	66	66	66	66	66
GEOTHERMAL	200	200	280	300	300	300	300	300	300	525	560	560	560
IMPORTS	252	252	252	252	252								
TOTAL FIRM	2465	2465	2545	2565	2565	2996	2936	3311	3311	3536	3571	3571	3571
SURPLUS/DEFICIT	394	271	219	99	-48	225	0	199	11	38	-139	-359	-595
ENERGY GENERATION - AVERAGE HYDRO YEAR													
GEOTHERMAL	200	200	280	300	300	300	300	300	300	525	560	560	560
HYDRO	1426	1560	1650	1682	1757	2093	2223	2430	2614	2766	2845	2930	3020
IMPORTS	252	252	252	252	252	252	252	252	252	207	252	252	252
THERMAL GEN REQ'D	193	182	144	232	304	126	161	130	134	0	51	188	334
TOTAL GENERATION	2071	2194	2326	2466	2613	2771	2936	3112	3300	3498	3708	3930	4166
INCREASE IN HYDRO	0	134	90	32	75	336	130	207	184	152	79	85	90
INCREASE IN THERMAL	18	-10	-38	88	72	-178	35	31	4	-134	51	137	146
LOAD FACTORS %													
HYDRO	51	56	59	60	63	52	55	60	52	55	56	58	60
TOTAL THERMAL	19	18	11	18	24	10	4	12	12	00	05	17	30
GEOTHERMAL	76	76	71	76	76	76	76	76	76	67	71	71	71
IMPORTS	96	96	96	96	96								
SYSTEM	68	68	68	68	68	68	68	68	68	68	68	68	68

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KIAMBERE HYDROELECTRIC PROJECT
Least Cost Analysis

	ALTERNATIVE A						ALTERNATIVE B							ALTERNATIVE C							
	CAPITAL + O&M			TOTAL		GRAND TOTAL	CAPITAL + O&M			FUEL	TOTAL		GRAND TOTAL	CAPITAL + O&M				FUEL	TOTAL		GRAND TOTAL
YEAR	KIAM	TURK	GEOTH	CAPITL	O&M		GAS T	COAL	KIAM		O&M	CAPTL		GAS T	GEOTH	KIAM	TURK		CAPTL	O&M	
1983	367			367	0	367	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1984	441			441	0	441	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1985	588			588	0	588	0	0	0	0	0	0	0	0	136	367	0	0	503	0	503
1986	563	279		842	0	842	248	269	0	0	0	517	517	363	136	441	0	0	940	0	940
1987	367	284		652	0	652	248	698	367	0	0	1313	1313	363	236	588	0	0	1187	0	1187
1988	150	382	136	641	28	668	94	937	441	315	39	1433	1786	136	677	563	0	315	1320	56	1691
1989	28	437	136	573	28	601	39	679	588	253	39	1267	1558	56	934	367	0	376	1268	89	1734
1990	28	497	236	709	52	760	39	378	563	326	193	787	1305	56	257	150	0	0	346	117	463
1991	28	286	677	939	52	990	39	154	367	345	193	367	905	56	33	28	284	0	284	117	400
1992	28	24	933	900	85	985	39	154	150	213	220	122	555	56	33	28	289	0	289	117	406
1993	28	24	257	224	85	309	39	154	28	291	220	0	511	56	33	28	437	0	437	117	554
1994	28	24	33	0	85	85	-292	154	28	315	220	-330	205	-484	33	28	497	0	-11	85	74
1995	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	472	0	448	85	533
1996	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	210	0	186	85	271
1997	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
1998	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
1999	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2000	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2001	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2002	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2003	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2004	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2005	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2006	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2007	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2008	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2009	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2010	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2011	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2012	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2013	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2014	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2015	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2016	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2017	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2018	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2019	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2020	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2021	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2022	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2023	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2024	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2025	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2026	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85
2027	28	24	33	0	85	85	39	154	28	315	220	0	535	0	33	28	24	0	0	85	85

8/8/83

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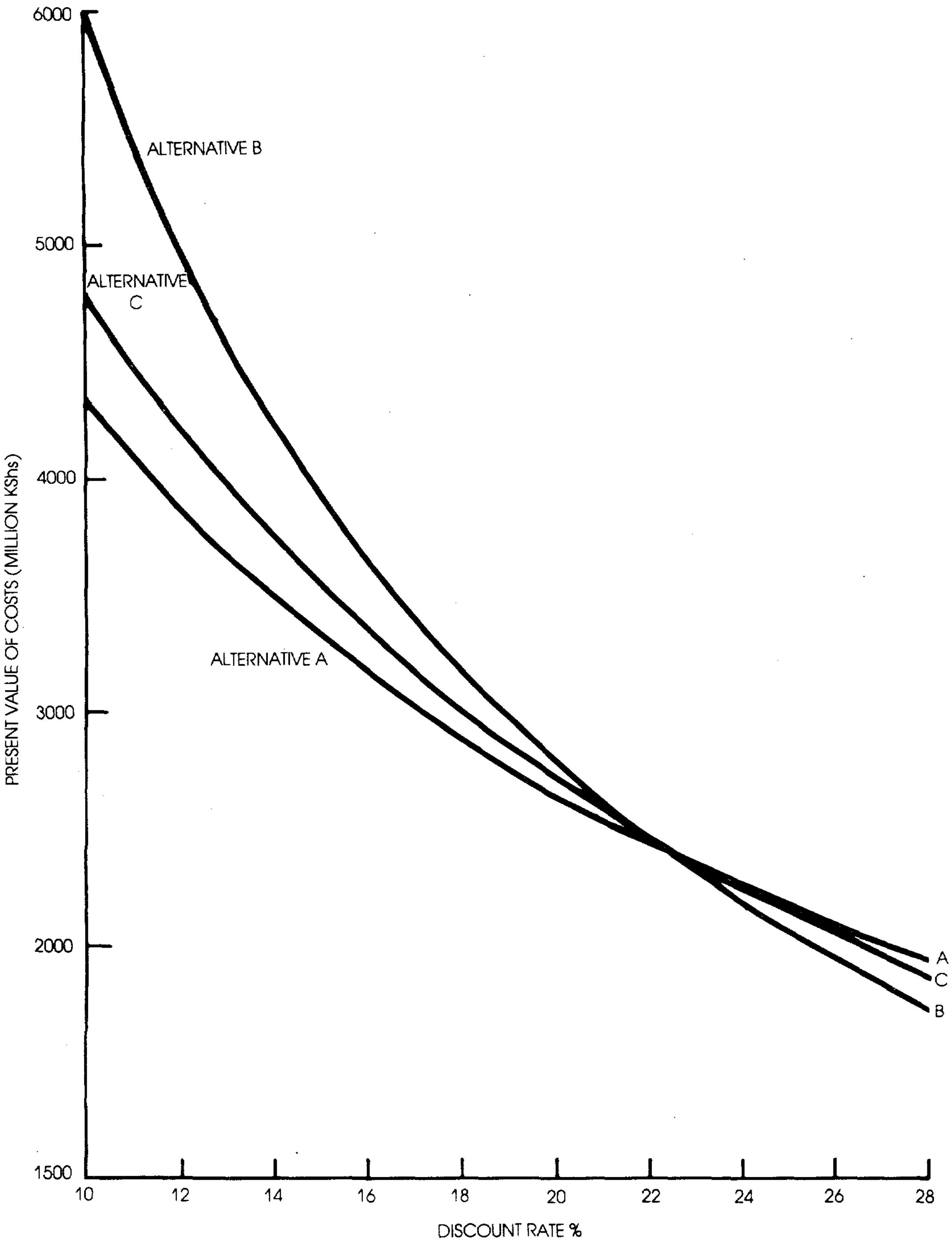
KIAMBERE HYDROELECTRIC POWER PROJECT
Present Values of Costs of Alternative Generation Programs at Various Discount Rates



August 8, 1983

World Bank—24914

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KIAMBERE HYDROELECTRIC POWER PROJECT

Economic Rate of Return

1. The Internal Economic Rate of Return (IERR) of the Kiambere project has been estimated as the discount rate which equalizes (a) the present value of the total incremental capital, operating and maintenance costs of the project plus the attributable incremental transmission, distribution, and related operation and maintenance costs to distribute Kiambere output to final consumers and (b) the present value of the benefits as measured by fuel savings and incremental revenues derived from sales of energy attributable to Kiambere. Tariffs used as proxy for economic benefits, understate the true economic benefits of power supply as they indicated lower value than the willingness to pay and, hence, the minimum value of electric power to the consumer. No attempt has been made to estimate the consumer surplus.

2. The following methodology and assumptions were used in calculating the economic rate of return:

Costs

(i) Costs based on mid-1983 prices, excluding IDC, duties and taxes and price escalation; project costs according to project cost estimates.

(ii) Foreign costs converted to Kenya shillings at 12.5 KShs/US$; shadow pricing not applied.

(iii) Local labor estimated at 15% of total costs shadow priced at 50%.

(iv) 50% of second 220 kV transmission line Mombasa - Nairobi capital costs (230 million KSh) on line 1990 attributed to the project.

(v) 6 million KSh/year general high voltage network reinforcement 1988-1992 and 50% of approximately 100 million KShs/yr low voltage distribution reinforcement and expansion 1988-1992 attributable to the project (the remaining portion is attributable to subsequent generating projects necessary to meet load growth after 1990 when the next plant would be needed). Source: KP&L Tariff Study, February 1982.

(vi) O&M costs - Kiambere 27.5 million KSh/year
- incremental transmission and distribution costs 10 million KShs/year.
- incremental commercial and administration costs 0.02 KShs/kWh sold.

Benefits

(vii) Kiambere output has been estimated by WLPU consultants (Table 6.8, Kiambere Project Summary Report, September 1982) using a system simulation model to determine the thermal generation required with and without Kiambere, Kiambere output being the difference in thermal generation in the two cases. The model takes into account existing plant as well as future plant additions acording to present KP&L long term plans. Output attributable to Kiambere which exceeds incremental sales plus losses has been valued at KSh 0.79 per kWh generated, based on a fuel oil price of US$180 per ton. Output attributable to Kiambere would increase from 377 GWh in 1988 to a maximum of 910 GWh/year by about 2000. Incremental sales are valued at the present average tariff (effective June 1983) of KSh 0.70 per kWh.

Study Period

(viii) Discounting is done over 40 years corresponding to the project construction period and the useful life of the Kiambere units and incremental transmission and distribution facilities; a residual value of 15% of total project cost was credited at the end of the study for the dam and civil works.

Cash flows of costs and benefits and output attributable to Kiambere are shown on page 3 of this annex.

Rate of Return

Base Case:	10.0%

Sensitivity

Capital cost + 10%:	9.4%
Tariff to give 12% IERR:	85 Kcts/kWh
Total demand reduced 10%:	9.5%

KIAMBERE HYDRO PROJECT - ECONOMIC RATE OF RETURN

CASHFLOWS - MID 1983 PRICES, KSHS MILLION

	COSTS							BENEFITS					
	CAPITAL			O&M			TOTAL COST	GWH			KSH MILLION		
YEAR	KIAMBERE	OTHER CAPITAL	TOTAL CAPITAL	KIAMBERE	OTHER	TOTAL		KIAMBERE OUTPUT	ATTRIB SALES	FUEL SAVINGS	INCR REVENUES	FUEL SAVINGS	TOTAL BENEFITS
1983	367	0	367	0	0	0	367	0	0	0	0	0	0
1984	441	0	441	0	0	0	441	0	0	0	0	0	0
1985	588	0	588	0	0	0	588	0	0	0	0	0	0
1986	563	2	565	0	0	0	565	0	0	0	0	0	0
1987	367	5	372	0	0	0	372	0	0	0	0	0	0
1988	122	92	214	28	14	41	256	377	134	219	94	173	267
1989	0	108	108	28	17	45	153	457	275	133	193	105	298
1990	0	96	96	28	20	48	144	542	424	43	297	34	331
1991	0	68	68	28	24	51	120	592	503	0	352	0	352
1992	0	62	62	28	28	55	117	610	519	0	363	0	363
1993	0	0	0	28	32	59	59	629	535	0	374	0	374
1994	0	0	0	28	36	63	63	649	552	0	386	0	386
1995	0	0	0	28	40	68	68	670	570	0	399	0	399
1996	0	0	0	28	45	72	72	694	590	0	413	0	413
1997	0	0	0	28	50	77	77	718	610	0	427	0	427
1998	0	0	0	28	55	82	82	745	633	0	443	0	443
1999	0	0	0	28	61	88	88	759	645	0	452	0	452
2000	0	0	0	28	66	94	94	776	660	0	462	0	462
2001	0	0	0	28	66	94	94	793	674	0	472	0	472
2002	0	0	0	28	66	94	94	830	706	0	494	0	494
2003	0	0	0	28	66	94	94	850	723	0	506	0	506
2004	0	0	0	28	66	94	94	869	739	0	517	0	517
2005	0	0	0	28	66	94	94	891	757	0	530	0	530
2006	0	0	0	28	66	94	94	906	770	0	539	0	539
2007	0	0	0	28	66	94	94	910	774	0	541	0	541
2008	0	0	0	28	66	94	94	910	774	0	541	0	541
2009	0	0	0	28	66	94	94	910	774	0	541	0	541
2010	0	0	0	28	66	94	94	910	774	0	541	0	541
2011	0	0	0	28	66	94	94	910	774	0	541	0	541
2012	0	0	0	28	66	94	94	910	774	0	541	0	541
2013	0	0	0	28	66	94	94	910	774	0	541	0	541
2014	0	0	0	28	66	94	94	910	774	0	541	0	541
2015	0	0	0	28	66	94	94	910	774	0	541	0	541
2016	0	0	0	28	66	94	94	910	774	0	541	0	541
2017	0	0	0	28	66	94	94	910	774	0	541	0	541
2018	0	0	0	28	66	94	94	910	774	0	541	0	541
2019	0	0	0	28	66	94	94	910	774	0	541	0	541
2020	0	0	0	28	66	94	94	910	774	0	541	0	541
2021	0	0	0	28	66	94	94	910	774	0	541	0	541
2022	-545	0	-545	28	66	94	-451	910	774	0	541	0	541

TARIFF 70 KCTS/KWH

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Long Run Marginal Cost of Supply

1. In order that consumers receive the correct price signal concerning the economic cost of electricity, tariffs should reflect the Long Run Marginal Cost (LRMC) of supply. The LRMC has been estimated by determining the Average Incremental Cost (AIC) of generation, transmission, distribution, and commercial administration to supply consumers of each voltage level. Details of the AIC calculation are to be found in the project file and are summarized below.

2. The AIC of generation has been estimated on the basis of incremental sales that can be provided from the Olkaria third geothermal unit and the Kiambere and Turkwel hydro projects which can satisfy load growth to early 1992. Further geothermal projects have not been included because costs are uncertain and there is a possibility that cheaper imports could be obtained from Uganda. Transmission and distribution costs not associated with generation projects are based on data given in the EAP&L tariff study of February 1982. Cost data and assumptions are the same as those used in the least cost analysis, Annex 21.

AIC Generation and Network Transmission

$$\text{AIC} = \frac{\text{Present value capital} + \text{O \& M costs}}{\text{Present value incremental generation}}$$

3. In the period 1985 - 1991 all incremental generation is attributable to hydro and geothermal plants and provides for load growth and fuel displacement. The incremental generation (on a base of 1984 generation) is assumed to remain constant at the level of added capacity (1192 GWh/yr) from 1992-2027, the end of the study.

AIC Transmission and Distribution

4. Based on past and future extension and reinforcement costs, the estimates for transmission and distribution facilities are as follows:

	Kcts/kWh (1983 prices)	Sales Weighting Factor
Transmission (EHV)	included with generation	0.02
Subtransmission (HV)	5.9	0.28
Distribution (LV)	6.6	0.70

The weighted average cost of sales (according to the proportion of sales and the cumulative cost at each voltage level) is estimated to be 9.7 Kcts/kWh.

Commercial and Administrative Costs

5. Average C & A costs in 1983 prices were estimated by KP&L at 6.7 Kcts/kWh. Incremental costs would be considerably less than average and are estimated at 2 Kcts/kWh.

Total Average Incremental Cost

6. The total AIC of sales to final consumers is the sum of the above costs assuming an opportunity cost of capital discount rate of 12%.

Generation incl. 15% loss	70.6	
Transmission and distribution	10.6	
Commercial and administrative	2.0	
Total AIC	83.2	Kcts/kWh

The above estimated AIC of 83.2 Kcts/kWh is about 17% higher than the present tariff level of 70 Kcts/kWh plus 1 Kct/kWh tax. While financial requirements can be met at the present tariff level, further increases would be justified on the grounds of encouraging economic efficiency.

KENYA

KIAMBERE HYDROELECTRIC POWER PROJECT

Selected Documents and Data Available in Project File

General Reports and Documents Related to the Sector

1. "Upper Reservoir Re-Construction Environmental Study (Sponsored by the United Nations Environment Program)" August 1976, Ward Ashcroft and Parkman, Hunting Technical Services Ltd., Incubon International Limited;

2. "Report on Geothermal Development at Olkaria," October 1977 (2 volumes), Merz and McLellan, Virkir Consulting Group Ltd.;

3. "Management and Accounting Consultancy Study," January 1978, Montreal Engineering Co. Ltd.;

4. "The National Power Development Plan, 1978-2000," May 1978 (2 volumes), Merz and McLellan and Sir Alexander Gibb and Partners;

5. "Justification Report for the National Power Development plan, 1978-2000," May 1978 (3 volumes), Merz and McLellan and Sir Alexander Gibb and Partners;

6. "Sondu/Miriu Ruter Multipurpose Development Project in Lake Victoria Bason Reconnaissance Report," February 1981, International Development Center of Japan;

7. "Economic Survey - 1982," June 1982, Central Bureau of Statistics, Ministry of Economic Planning and Development;

8. "Turkwel Hydroelectric Project - Feasibility Report," June 1982, SOGREAH.

General Reports and Studies Related to the Project

1. "Kiambere Hydroelectric Development Feasibility Study," April 1980 (2 volumes), Engineering and Power Development Consultants;

2. "Kiambere Hydroelectric Project, Pre-Investment Report," June 1981, Watermeyer, Legge, Piesold and Uhlmann, Ewbank and Partners Ltd.;

3. "Kiambere Hydroelectric Project - Project Summary," September 1982, Watermeyer, Legge, Piesold and Uhlmann, Ewbank and Partners Ltd.;

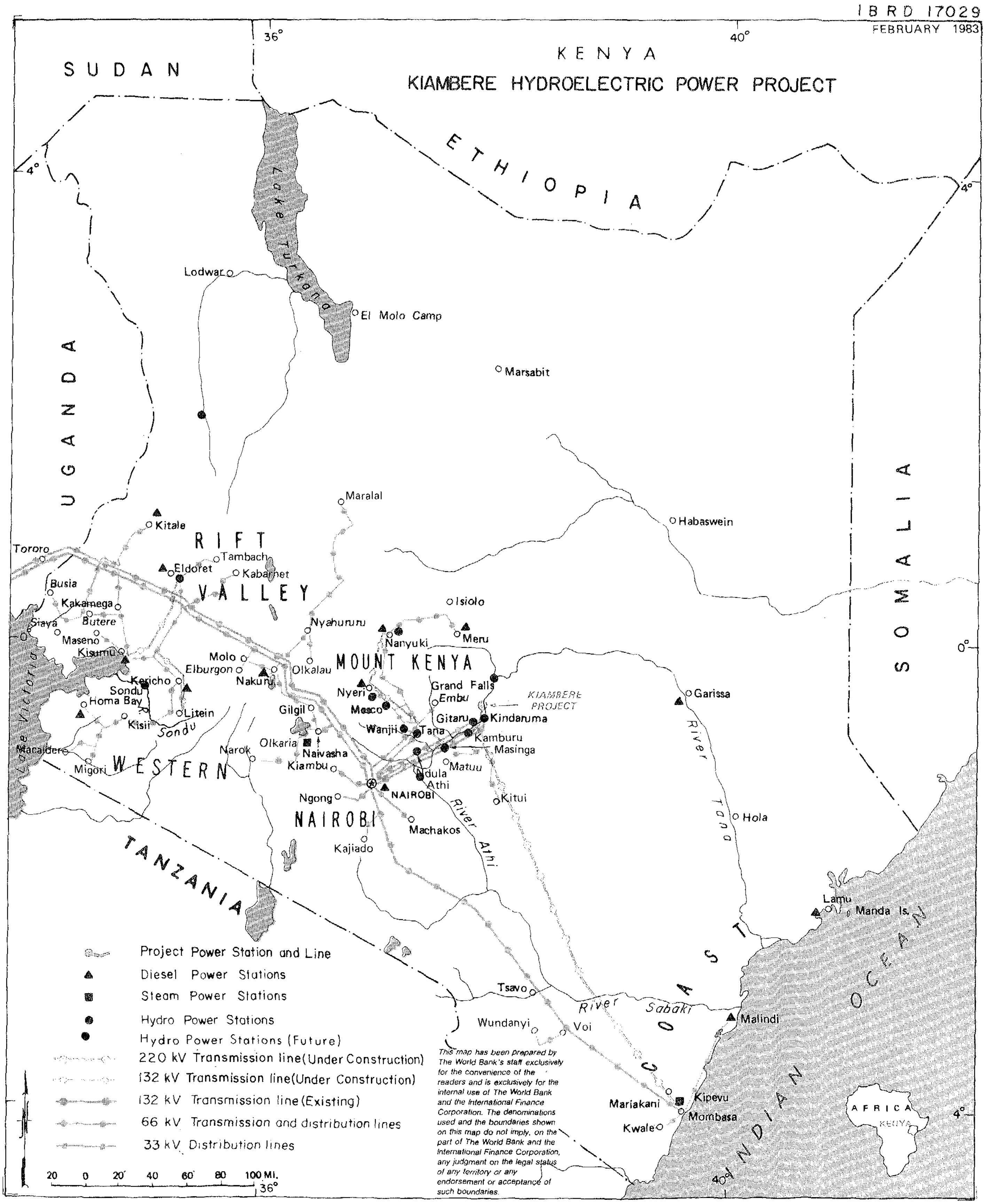
4. "Kiambere Hydroelectric Project - Review Board Report," November 1982, S. Blaj, M. Amow, J.V. Sutcliffe;

5. "Kiambere Hydroelectric Project - Project Cost Review" December 1982, Montreal Engineering Company Ltd.;

6. "Kiambere Hydroelectric Project - Geological Report," November 1982 (Draft), Dr. L. Wolofsky.

Selected Working Papers

- Computer printouts and discounted cash flow studies for load forecast and economic analysis;
- Project cost estimates and sensitivity studies; and
- Financial and accounting statements.



IBRD 17029
FEBRUARY 1983
KENYA
KIAMBERE HYDROELECTRIC POWER PROJECT
SUDAN
ETHIOPIA
UGANDA
SOMALIA
TANZANIA
RIFT VALLEY
WESTERN
NAIROBI
MOUNT KENYA
COAST
INDIAN OCEAN
Lake Turkana
Lake Victoria
Lodwar
El Molo Camp
Marsabit
Maralal
Habaswein
Kitale
Tororo
Tambach
Eldoret
Kabarnet
Busia
Kakamega
Butere
Siaya
Maseno
Kisumu
Molo
Elburgon
Nakuru
Olkalau
Nyahururu
Isiolo
Nanyuki
Meru
Kericho
Sondu
Homa Bay
Kisii
Litein
Sondu
Nyeri
Mesco
Grand Falls
Embu
KIAMBERE PROJECT
Garissa
Gilgil
Gitaru
Kindaruma
Wanjii
Tana
Kamburu
Masinga
Olkaria
Naivasha
Narok
Kiambu
Macalder
Migori
Ndula
Matuu
Athi
NAIROBI
Ngong
Kitui
Machakos
Kajiado
River Athi
River Tana
Hola
Lamu
Manda Is.
Tsavo
River Sabaki
Malindi
Wundanyi
Voi
Mariakani
Kipevu
Mombasa
Kwale
AFRICA
KENYA
36°
40°
4°
0°
Project Power Station and Line
Diesel Power Stations
Steam Power Stations
Hydro Power Stations
Hydro Power Stations (Future)
220 kV Transmission line (Under Construction)
132 kV Transmission line (Under Construction)
132 kV Transmission line (Existing)
66 kV Transmission and distribution lines
33 kV Distribution lines
20 0 20 40 60 80 100 MI.
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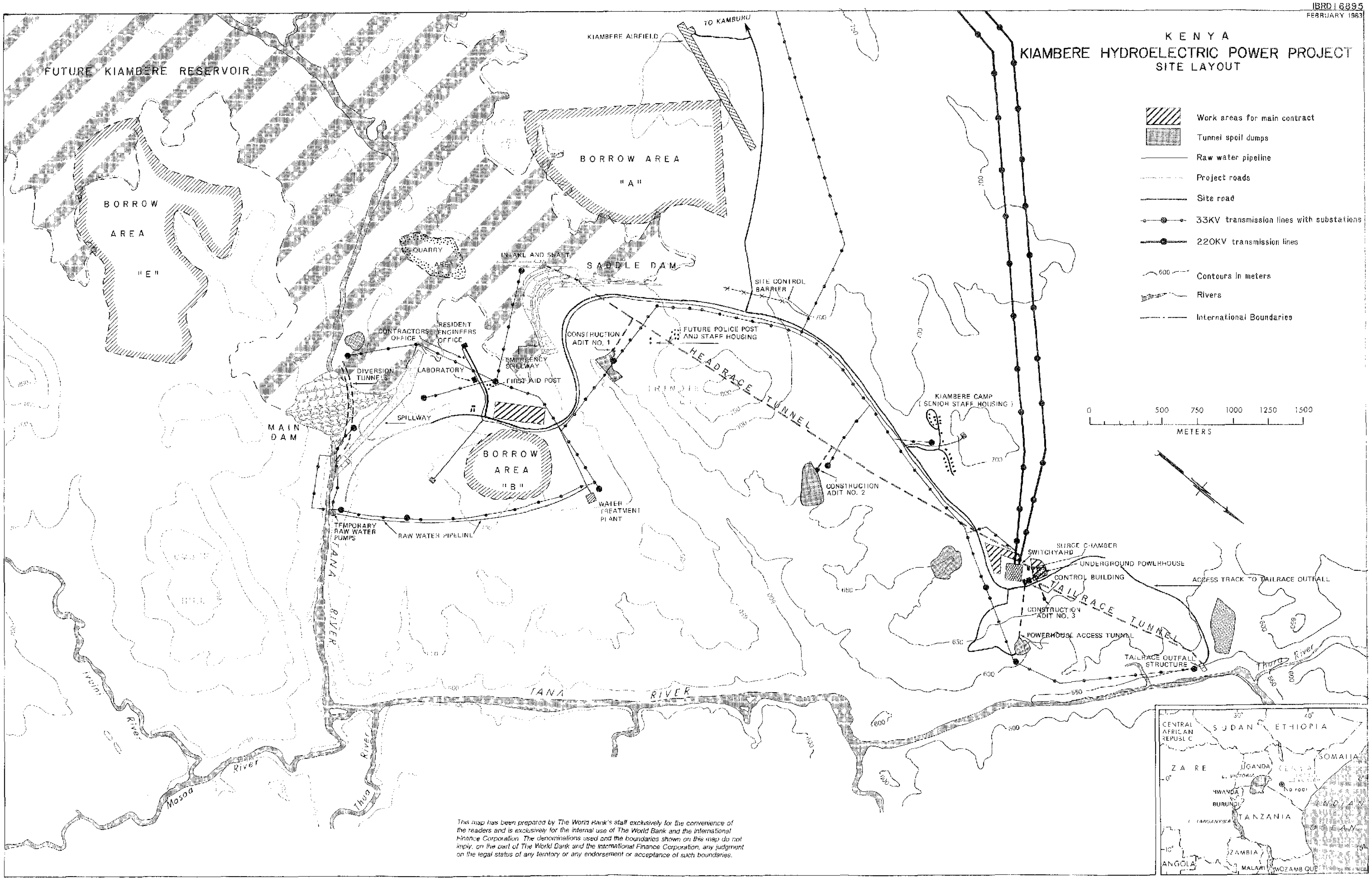

IBRD 16895
FEBRUARY 1983
KENYA
KIAMBERE HYDROELECTRIC POWER PROJECT
SITE LAYOUT
Work areas for main contract
Tunnel spoil dumps
Raw water pipeline
Project roads
Site road
33KV transmission lines with substations
220KV transmission lines
Contours in meters
Rivers
International Boundaries
0 500 750 1000 1250 1500
METERS
FUTURE KIAMBERE RESERVOIR
BORROW AREA "E"
BORROW AREA "A"
BORROW AREA "B"
KIAMBERE AIRFIELD
TO KAMBURU
QUARRY AREA
INTAKE AND SHAFT
SADDLE DAM
SITE CONTROL BARRIER
CONSTRUCTION ADIT NO. 1
FUTURE POLICE POST AND STAFF HOUSING
HEADRACE TUNNEL
CONTRACTORS OFFICE
RESIDENT ENGINEERS OFFICE
DIVERSION TUNNELS
LABORATORY
EMERGENCY SPILLWAY
FIRST AID POST
SPILLWAY
MAIN DAM
KIAMBERE CAMP (SENIOR STAFF HOUSING)
CONSTRUCTION ADIT NO. 2
WATER TREATMENT PLANT
TEMPORARY RAW WATER PUMPS
RAW WATER PIPELINE
SURGE CHAMBER
SWITCHYARD
UNDERGROUND POWERHOUSE
CONTROL BUILDING
ACCESS TRACK TO TAILRACE OUTFALL
TAILRACE TUNNEL
CONSTRUCTION ADIT NO. 3
POWERHOUSE ACCESS TUNNEL
TAILRACE OUTFALL STRUCTURE
TANA RIVER
Thua River
Mutini River
Masoa River
CENTRAL AFRICAN REPUBLIC
SUDAN
ETHIOPIA
ZAIRE
UGANDA
KENYA
SOMALIA
RWANDA
BURUNDI
TANZANIA
INDIAN OCEAN
ZAMBIA
ANGOLA
MALAWI
MOZAMBIQUE
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