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KENYA GEOTHERMAL PRIVATE POWER PROJECT: A PREFEASIBILITY STUDY

Topical Report

October 1992

Work Performed Under Contract No. DE-FG07-89ID12850

For
U. S. Department of Energy
Office of Industrial Technologies
Washington, D.C.

By
National Geothermal Association
Davis, CA 95617-1350

DISCLAIMER

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Section I EXECUTIVE SUMMARY

A. PRINCIPAL FINDINGS

Twenty-eight geothermal areas in Kenya were evaluated and prioritized for development. The prioritization was based on the potential size, resource temperature, level of exploration risk, location, and exploration/development costs for each geothermal area. Suswa, Eburru and Arus are found to offer the best short-term prospects for successful private power development. It was found that cost per kW developed are significantly lower for the larger (50MW) than for smaller-sized (10 or 20 MW) projects. In addition to plant size, the cost per kW developed is seen to be a function of resource temperature, generation mode (binary or flash cycle) and transmission distance.

For the 3 sites with prospectively the most attractive development potential, estimated geothermal development costs range from about US$2,538/kW (including interest during construction) for a 50 MW plant to approximately US$3,324/kW (including interest during construction) for a 20 MW plant. Estimated cost per kWh, based on sensitivity analysis of avoided costs, financing mix, tax concessions and plant size, are within the range of the Kenya Power and Lighting Company's (KPLC) own geothermal development costs. At these levels, returns from development appear to offer an attractive prospect for foreign investors.

KPLC sales of some 2,461 GWh and peak demand of about 480 MW in 1988-89 will both double by about the year 2001-02. New capacity added during the period 1988-89 to 2001-02 will need to be equal in magnitude to all capacity already constructed. This expansion will impose not only a financial challenge but also a substantial logistical challenge for KPLC.

The purchase of additional or replacement capacity from private sources has a number of potential benefits for KPLC. These include such possible tangible and measurable benefits as lower prices for power, lower capital outlays for development, shorter development lead time and reduced workload for scarce KPLC project-management personnel. Furthermore, numerous important uncertainties are reduced and risks are shifted by pursuing private purchases. These include reducing the risks and financial burden of geothermal exploration, reducing the risk of capacity or energy shortfalls due to project delays and higher-than-forecast energy or capacity growth, and reducing the burden of pursuing and acquiring capital loans in a constrained financial market.

Private power development in Kenya could follow one of several models. One of the most common is the Build-Own-Operate-Transfer (BOOT) approach. Under this approach, private developers would explore, drill development wells, construct a power station and sell power to KPLC for an agreed period. The project would thereafter transfer to KPLC (or KPC) at under mutually agreed terms. Another option is the Build-Own-Operate (BOO) approach, under which no transfer of ownership takes place.

The Government of Kenya (GOK) has taken a number of actions to encourage private development of its geothermal resources and is aware of the critical role of foreign investment. In May 1990, the Geothermal Resources Act of 1982 was implemented, allowing private-sector geothermal development. The main assurances a private-sector developer would need are addressed, including rights to the resource, rights to sell steam or electricity and rights to repatriate income sufficient to meet debt burden and make a reasonable return on investment. Geothermal private power development requires the granting of a Geothermal Resources License and a license under the Electric Power Act, both to be granted by the Ministry of Energy (MOE); and in addition, a Mineral Lease consistent with the Mining Act of Kenya.

Nonetheless, since a private geothermal undertaking would be a first of its kind in Kenya, it would still impose substantial risks on the developer. These include political and economic risks; for example, ability to obtain an adequate price for power to allow a reasonable return on investment, risk regarding conversion of revenues into foreign exchange, risk of changes in government policy or new legislation, risk of changes in taxation or duties, or force majeure. For this reason and given the strong public interest in the project's success, strong support and encouragement from the GOK, MOE and KPLC is essential for such a venture.

In pursuing private power development in Kenya, the GOK would be able to benefit from the experience of many other developing countries, including Pakistan, the Philippines, Thailand, Indonesia, the Dominican Republic, Costa Rica and Turkey. Each of these countries has initiated policies and regulations encouraging private sector participation in their power supply plans. U.S. A.I.D would like to cosponsor with the Government of Kenya, a conference on opportunities for private investment in the power sector in Kenya.

B. RECOMMENDED PLAN OF ACTION

KPLC and MOE are invited to review and critique this report. The input and participation of both KPLC and MOE are critical to success of any private power effort. The team representing the U.S. geothermal industry which has prepared this report will respond to all comments, and will arrange to hold more detailed discussions with the GOK on geothermal private power development at the earliest opportunity. The report concludes that the development of a private geothermal project will require the following steps:

1. Review of this report by KPLC and MOE, and revision of the report based on this review, followed by meetings to present findings and conclusions.

2. Agreement in concept by the KPLC and MOE to the development of a geothermal private power project in Kenya along the lines of this report, or as modified based on the considerations of KPLC and the GOK.

3. Completion of a Memorandum of Understanding (MOU) between the appropriate Kenya government agencies and a U.S. geothermal developer, and related agreements which include:

a. A joint-venture agreement, potentially with KPLC as a local joint-venture partner.

b. Granting of a Geothermal Resources License to drill, extract and utilize the resource, including confirmation of the availability of all concessions to the joint venture, and agreement on the general terms and conditions of a power sales contract; and a license under the Electric Power Act.

c. Granting a Mineral Lease consistent with the Mining Act.

4. The U.S. geothermal developer will solicit and obtain funding for a full feasibility study, including any funds required for exploration drilling, with a reasonable contribution of funds, services or other support by the local joint-venture partner.

5. The U.S. developer and local joint-venture partner would present results of feasibility study and, following acceptance, would finalize the necessary development agreements (geothermal lease, power purchase agreement, and construction, management and operations agreement) and operational convenants (tax treatment, currency treatment, etc.) with the responsible Kenya government agencies.

C. OTHER ISSUES

The successful development of private power in Kenya depends in large measure upon the degree to which KPLC and the MOE commit to the success of this approach and integrate the approach in KPLC's future capacity plans. One means of ensuring this commitment would be for KPLC to allocate a portion of its new capacity requirement to the private sector for development. This would signal a solid commitment by GOK and greatly facilitate establishing the local conditions necessary for successful project development.

Local participation in this type of project is important at all phases to ensure that it is designed and developed in a manner to serve the best interests of Kenya. Mobilization of local capital, potentially to participate through local currency in the long-term financing pool, is another area which GOK may wish to explore.

II. INTRODUCTION

A. BACKGROUND

In June, 1988, during the preparations for a U.S. geothermal industry definitional trade and investment mission to Kenya, a strategy for development of a private power project in Kenya began to take shape. During that mission and later, the MOE and KPLC identified rapidly growing demand and capital constraints which jeopardized their ability to provide adequate new electricity supply. Subsequently, the MOE and KPLC agreed on the desirability of exploring private power alternatives, and developed implementing regulations for private geothermal development. Oak Ridge Associated Universities continued this initiative through the Renewable Energy Applications and Training Project of A.I.D., and sought U.S. industry involvement through the National Geothermal Association (NGA).

In mid-1990, funding was approved from the U.S. A.I.D., U.S. Department of Energy (DOE) and the U.S. Trade and Development Program (TDP) to perform this private power prefeasibility study. The study is intended to gather and analyze technical, financial and institutional information, and help to define a private power approach to develop geothermal resources in Kenya. Specifically, the Kenya Geothermal Private Power Study is intended to evaluate various potential sites for geothermal development, evaluate the impact of private power development on the existing and future generation system, review the laws and regulations for private power development in Kenya, and generally to determine the legal and financial feasibility of a private geothermal project in Kenya.

The U.S. geothermal industry has been represented in this effort, by the NGA via its members GeothermEx, Inc. and the Ben Holt Company, and Venable Associates. Interest in Kenya arises from the desire of the U.S. industry to play a role in development of geothermal resources in Kenya, and because of the expressed interest on the part agencies of the GOK in pursuing this opportunity.

Report Format. The report which follows comprises a prefeasibility study for a private power development of a geothermal electric generation project in Kenya. Section III of the report provides a brief assessment of the state of the Kenya power systems, the need for power, financial requirements, and the prospective benefits of private power development. Report Section IV provides an assessment of the existing geothermal program and the geothermal resources of Kenya, along with a ranking of prospective sites for development. The costs for development are estimated in Sections IV and V for a range of plant sizes; a financial analysis is performed in Section VII on the potential rate of return to a private developer under a range of assumptions. Section VI of the report contains a brief review of the experience of a number of other countries with private power. A review of various methods for valuing private power and power pricing is also presented in Section VI. Section VIII contains a review of the local institutional and legal and regulatory framework for private power development and a discussion of the major legal issues pertaining to private power project development.

III. An Assessment of the Status of Kenya's Power Sector and Implications of Private Power for The Kenya Power and Lighting Company

A. Overview

The power industry in Kenya is largely owned by the Kenya Government, and is comprised of 3 entities. These are The Kenya Power and Lighting Company (KPLC), The Kenya Power Company (KPC), and The Tana River Development Company (TRDC). The Kenya Power and Lighting Company is owned 49% by the Government of Kenya (GOK) and 9.7% by other Governmental institutions. The balance of shares are owned by Kenya residents (34%) and non-residents (7%). KPLC is responsible for the overall distribution of electricity in the country, owning the distribution network, as well as certain standby facilities such as Kipevu in Mombasa, and several small diesels and hydro units.

The Kenya Power Company is owned entirely by the GOK and is responsible for the development of new hydroelectric and geothermal generation facilities and power purchases from Uganda. KPC is the owner of Tana river hydro facilities and the Olkaria geothermal power stations. KPC is in the process of acquiring the Kiambere and Masinga stations of the Tana River Regional Development Authority (TARDA) and Turkwell power station from the Kerio Valley Development Authority. KPC is also undertaking the planning for the Sondu Miriu hydropower project. The Tana River Development Company is also wholly owned by GOK, and presently owns the Kamburu, Gitaru and Kindaruma hydro stations. TRDC sells in bulk to KPLC at cost.

The basic framework for power system planning in Kenya is the Kenya National Power Development Plan 1986-2006 (KNPDP), prepared by Acres International Ltd in 1987. The KNPDP provided a new least-cost generation and transmission plan for Kenya. This plan represents the latest long-term development plan for the power sector available. Although the KNPDP has not been officially endorsed, it is believed to represent the best comprehensive basis for planning. This plan has been overcome by events in some areas, however, for example demand growth has been more rapid than forecast, and power development schedules have slipped. In this study we have therefore made adjustments in forecast demand, new capacity scheduling and costs, among other areas, based on input from KPLC, in order to reflect the current demand and supply situation and the best judgement of KPLC on various planning assumptions.

Table III - 1 The Kenya Power and Lighting Company

Historic Sales of Electricity by Customer Category
(GWH)

Customer Category	1984	1985	1986	1986/87	1987/88	1988/89	1989/90	Compound Growth Rate (5.5 yrs)
Domestic, Small Commercial and Industrial	514	545	292	634	678	729	780	7.9%
Medium Commercial and Industrial	455	472	252	536	555	515	554	3.6%
Large Commercial and Industrial	681	812	434	916	982	1041	1127	9.6%
Off-Peak	116	106	53	111	110	113	116	0.0%
Street Lighting	9	9	4	9	12	14	14	8.4%
Total	1,775	1,944	1,035	2,206	2,337	2,412	2,591	7.1%
Per Cent Increase per Year		9.5%		8.8%	5.9%	3.2%	7.4%	

B. Power Demand and Supply

1. Current and Future Demand for Electric Power

Historically the demand for energy and peak load power requirements in Kenya have grown rapidly, reflecting substantial growth in the industrial sector, as well as rapid urbanization of the country. Year to year fluctuations have also been significant as the affects of economic conditions flow through to power sales. In 1989 for example, energy sales growth dropped to 3.23% from 6% in the previous year. This was primarily due to a decline in sales to industry. Table III-1 above summarizes the historic energy and power requirements met by the Kenya power system.

Forecasts of future energy and power are extremely important in determining the plans for necessary new capacity. For purposes of this report, we have utilized forecasts prepared for KPLC by Ewbanks-Preece, covering the period 1985-86 to 2005-6. Forecasts incorporate estimates of total system sales, average losses, generation station internal use, system peak demand and system load factor. Table III-2 summarizes these data.

The basic picture given by the projections in Table III-2 is of a system with substantial continuing growth, about 5.4% in energy and peak demand. The implications of these forecasts is that sales of some 2,461 GWh and peak demand of about 480 MW in 1988/89 will both double by about the year 2001-2. Correspondingly, new capacity added during this period will need to be equal in size to all capacity already constructed to 1990. Given the higher prices for new capacity today, and the short time period during which this capacity will be needed, this expansion will impose not only a financial challenge but also a substantial logistical challenge for KPLC.

2. Kenya Electric Power Supply

a. Power Supply Characteristics

The current electric power system in Kenya is made up of somewhat over 800 MW of installed capacity, with an effective generation capability of about 550 MW. Of this effective capacity, 375 MW are hydroelectric, 130.5 MW are oil-fired, and 43 MW are geothermal. Due to the addition of 85.7 MW effective capacity from the Turkwell hydroelectric plant in 1992-93, effective capacity rises to about 664 MW in that year. Given current and projected energy demand, this capacity will be able to provide all capacity requirements (on an average hydro year basis) in 1992-93, but allowing only a 14 MW reserve, where 95 MW are required to maintain the 15% reserve margin desired by KPLC.

Even with the optimistic assumption that Kenya will be able to add the Sondu Miriu and Sererwa hydro projects for a total capacity of 49.4 MW by 1996-97, and geothermal capacity in the Olkaria Northeast field of 64 MW by 1994-95, the system by the year 2001-02 would still require an additional 165 MW geothermal and 180 MW of coal. Table III-3 details existing capacity and capacity additions planned by fuel type. Table III-4 provides estimated generation from existing and planned capacity.

b. Resource Options

The geothermal resources of Kenya are among the best in the world and are described in some detail in Section IV below. In addition to geothermal potential, Kenya is endowed with substantial hydroelectric resources. Identified undeveloped hydroelectric resources in Kenya total over 1,400 MW of capacity and 6,000 GWh of average energy. This potential is found in 5 major river systems, the Tana River basin with about 40% of the total, 30% in the Lake Victoria basin, and about 10% each in the Ewaso Ngiro North, Rift Valley and Athi River basins. After the Turkwell River project, about to be completed, the most attractive projects appear to be the Sondu Miriu and the Sererwa projects, respectively.

The Sondu Miriu project is being programmed for 1996-97, and would produce about 31 MW firm capacity and average energy of 277.6 GWh. The Sererwa project would provide about 18.4 MW of power and an average of 157 GWh. Economics and feasibility of the Sondu Miriu project are currently under final review. The Sererwa project is essentially a peaking power plant which would operate only during system peak periods. The KNPDP recommended further studies of this latter option. Apparently a feasibility study has recently been completed for Sererwa, but was not obtained for purposes of preparing this report. Finally, consideration is being given to a 72.5 MW third unit at Gitaru. The KNPDP did not incorporate this unit at Gitaru due to its high cost. Additional hydro potential at High Grand Falls, Leshota and Magwagwa was noted in the KNPDP, and further prefeasibility studies will apparently be undertaken on these areas in the future.

Kenya has no developed oil, gas or coal resources. It must therefore import all its fossil energy resources, and currently refines crude oil resources to provide for fuel for oil-fired generation, transport and industry, among other uses. Although coal-fired generation is recommended in the KNPDP, Kenya has no commercially exploitable coal resources, although nearby Tanzania and Zimbabwe both have significant coal resources. Substantially expanded coal use in Kenya would require substantial investment in coal handling and storage at the Port of Mombasa which have not been factored into the estimated cost of coal power generation included in this paper.

Table III - 2 The Kenya Power and Lighting Company -
Forecast of Capacity and Energy Requirements

Generation Type	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Capacity (MW)																	
System Peak	527	558	589	620	653	687	724	762	803	846	893	942	994	1,049	1,105	1,163	1,225
Peak plus Reserve Margin	606	642	677	713	751	790	833	876	923	973	1,027	1,083	1,143	1,206	1,271	1,337	1,409
Energy (GWH)																	
Energy Demand	2,591	2,805	2,956	3,108	3,269	3,438	3,616	3,809	4,004	4,218	4,449	4,692	4,947	5,213	5,486	5,772	6,075
Losses & Own Use	430	454	479	503	530	557	586	617	649	683	721	760	801	845	889	935	984
Station Use	43	46	48	51	59	62	65	69	72	76	80	85	85	85	85	85	85
Estimated Losses	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%
Gross Generation	3,127	3,305	3,483	3,663	3,853	4,052	4,261	4,484	4,718	4,970	5,242	5,528	5,829	6,142	6,464	6,801	7,157

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Table III - 3 The Kenya Power and Lighting Company -- Capacity Plans
(Megawatts)

Generation Type	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Hydroelectric																		
Tana, Wanjii, Other	19.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Kamburu	84	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
Gitaru	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Kindaruma	44	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Masinga	40	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Kiambere	140	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
Turkwell				42.9	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7
Sondu Miriu								31	31	31	31	31	31	31	31	31	31	31
Sererwa									18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Magwagwa																		
Uganda	30																	
Hydroelectric (Total)	502.8	374.7	374.7	417.6	460.4	460.4	460.4	491.4	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8
Coal (Total)												60	120	120	180	180	240	240
Oil Steam																		
Kipevu	4	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5		
Gas Turbine																		
Kipevu JBE	30	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nairobi South	13.8	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0									
Other Gas Turbine					30.0	90.0	90.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Oil-Fired (Total)	47.8	130.5	130.5	130.5	160.5	220.5	220.5	250.5	250.5	238.5	238.5	238.5	238.5	238.5	238.5	238.5	150	150
Geothermal																		
Olkaria East	43	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Olkaria North-East							32	64	64	64	64	64	64	64	64	64	64	64
Other Geothermal											55	55	55	110	110	165	165	220
Geothermal (Total)	43	43.2	43.2	43.2	43.2	43.2	75.2	107.2	107.2	107.2	162.2	162.2	162.2	217.2	217.2	272.2	272.2	327.2
Total Capacity	593.6	548.4	548.4	591.3	664.1	724.1	756.1	849.1	867.5	855.5	910.5	970.5	1030.5	1085.5	1145.5	1200.5	1172	1227

Table III - 3 The Kenya Power and Lighting Company -- Capacity Plans
(Megawatts)

Generation Type	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Hydroelectric																		
Tana, Wanjii, Other	19.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Kamburu	84	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
Gitaru	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Kindaruma	44	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	~~44.0~~	~~44.0~~
Masinga	40	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Kiambere	140	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
Turkwell				42.9	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7
Sondu Miriu								31	31	31	31	31	31	31	31	31	31	31
Sererwa									18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Magwagwa																		
Uganda	30																	
Hydroelectric (Total)	502.8	374.7	374.7	417.6	460.4	460.4	460.4	491.4	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8	509.8
Coal (Total)												60	120	120	180	180	240	240
Oil Steam																		
Kipevu	4	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5		
Gas Turbine																		
Kipevu JBE	30	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nairobi South	13.8	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0									
Other Gas Turbine					30.0	90.0	90.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Oil-Fired (Total)	47.8	130.5	130.5	130.5	160.5	220.5	220.5	250.5	250.5	238.5	238.5	238.5	238.5	238.5	238.5	238.5	150	150
Geothermal																		
Olkaria East	43	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Olkaria North-East							32	64	64	64	64	64	64	64	64	64	64	64
Other Geothermal											55	55	55	110	110	165	165	220
Geothermal (Total)	43	43.2	43.2	43.2	43.2	43.2	75.2	107.2	107.2	107.2	162.2	162.2	162.2	217.2	217.2	272.2	272.2	327.2
Total Capacity	593.6	548.4	548.4	591.3	664.1	724.1	756.1	849.1	867.5	855.5	910.5	970.5	1030.5	1085.5	1145.5	1200.5	1172	1227

Table III - 4 The Kenya Power and Lighting Company -- Energy Production by Unit
(GWH)

	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
Hydroelectric																		
Tana, Wanjii, Other	159	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Kamburu	400	285	285	285	285	285	285	285	285	285	285	285	285	285	285	285	285	285
Gitaru	779	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562	562
Kindaruma	214	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Masinga	103	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119
Kiambere	794	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626
Turkwell				134	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Sondu Miriu								277.6	277.6	277.6	277.6	277.6	277.6	277.6	277.6	277.6	277.6	277.6
Sererwa									157	157	157	157	157	157	157	157	157	157
Magwagwa										334	334	334	334	334	334	334	334	334
Uganda	112	10	203	81	162	203												
Hydroelectric (Total)	2561	1860	2053	2065	2280	2321	2118	2396	2553	2553	2553	2553	2553	2553	2553	2553	2553	2553
Coal												421	841	841	1262	1262	1682	1682
Oil Steam																		
Kipevu	25	623	623	623	623	623	623	623	623	623	623	623	623	623	623	623		
Gas Turbine																		
Kipevu JBE	20	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208
Nairobi South	1	83	83	83	83	83												
New Gas Turbine					202	607	607	809	809	809	809	809	809	809	809	809	809	809
Diesel	13	6	6	6	6	6												
Oil-Fired (Total)	59	921	921	921	1123	1528	1439	1641	1641	1641	1641	1641	1641	1641	1641	1641	1018	1018
Geothermal (Total)	322	353	353	353	353	353	610	867	867	867	1309	1309	1309	1751	1751	2193	2193	2634
							257	514	514	514	956	956	956	1398	1398	1840	1840	2281
Gross Generation	2942	3134	3327	3339	3756	4202	4167	4904	5061	5061	5503	5923	6344	6786	7206	7648	7445	7886
Est'd Losses/Own Use	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%
Generation Available for Sale	2465	2626	2788	2798	3148	3521	3492	4109	4241	4241	4611	4964	5316	5686	6039	6409	6239	6609

File:fener.wk3

C. Kenya's Electricity Supply Program

1: Least-Cost Supply Plan

The KNPDP or so-called "Master Plan" for electric power development in Kenya completed in 1987, provides the basis for much of the planning for new generation today by KPLC and was used extensively for this prefeasibility study. Updates and additional analysis of the Kenya electricity supply program have been undertaken recently by Ewbanks Preece for KPLC due to changes in demand for energy, as well as changing costs of new capacity and other factors. KPLC itself and various other consultants continue to further refine these plans as part of the planning and feasibility work for various new generation projects. Any changes in the KNPDP (ACRES Report) have been incorporated in the prefeasibility study to the extent information was available.

a. Methodology

It is important to understand the basic framework for supply planning in order to appreciate the comparison which will be presented later between private power alternatives and the KPLC planned generation program. This section presents a brief overview of the major considerations going into the planning process.

The basic supply plan of KPLC is designed to allow the utility to reliably meet future peak demands and energy requirements, while at the same time, minimizing the cost of providing this service. The planning process incorporates consideration of many factors, some of the technical factors include the reliability of equipment, maintenance needed and cost of new generation, and planning and construction requirements and lead times; and the other uncertainties, for example, as in future levels and geographic locations of electricity load growth, hydro conditions caused by dry weather, and fuel availability and cost. Given the uncertainties in these factors, sensitivity analysis is used to test various alternatives against these factors.

The limited analysis of supply alternatives in this study could not possibly duplicate or attempt to redo the supply plan of KPLC. However, this study did involve both a thorough review of the KNPDP and its various revisions. This review was basically intended to permit a better understanding of the economic and other implications of providing additional generation to KPLC through private means.

b. Description of Plan

The KNPDP consists of a mix of new generation, schedule for retirements, assumed purchases from Uganda, growth projections for energy and power, financial requirements and resulting reliability implications. The supply analysis in this report takes this information as given, as modified by the Ewbanks-Preece report, and analyses the implications of private power alternatives to this plan. The principal differences which are analyzed are: project cost, timing, and differences in oil generation requirements and unserved energy which result. Since both the KNPDP and the Ewbanks-Preece report assume that all energy requirements will be met, the analysis of unserved energy is for sensitivity analysis purposes to inform KPLC of the costs of not undertaking plans as scheduled, and the equivalent benefit if private power additions permit these hypothetical short-falls to be avoided.

c. Planning Assumptions and Expansion Plans

For this report we have attempted to be as consistent as possible with the planning assumptions used in the KNPDP and Ewbanks-Preece work. In general we have used the most recent data available, or in the case of several values have attempted to use the mean or most likely value, with sensitivity analysis used to evaluate the impact of divergence from this value. Table III-7 section presents the basic assumptions used for this analysis. These include capital and operating and maintenance costs, scheduled and forced outage rates, fuel costs, and fuel cost escalation (only for oil). Estimates for planned hydro output and costs are based KPLC's latest figures.

d. Major Planning Issues and Uncertainties

As part of both the general review of the KNPDP and subsequent analysis of expansion plans, the following major issues or uncertainties were identified which are the subject of analysis in this report:

1. Fuel prices and escalation rates
2. Energy and peak demand growth
3. Hydroelectric generation levels realized, and output and timing for additional hydro additions.
4. Geothermal development and production rates, economics and lead times; and lead times for other types of capacity (i.e. combustion turbines).
5. Generation financing (Section VI).
6. Unserved energy costs.

D. Comparison of KPLC and Private Power Alternatives

1. Methodology for Comparison of KPLC LCP and Private Power Alternatives

The analysis in this section is intended to demonstrate the potential advantages of private geothermal development in terms of reducing costs and risks of higher energy demand than forecast, higher oil prices, delay in KPLC expansion plans and higher KPLC geothermal costs. Advantages are demonstrated primarily through a comparisons of economic costs and benefits. These relative costs and benefits depend essentially on the costs of new capacity and directly associated transmission, and not on cost differences derived from total system expansion analysis. The incremental costs and the various costed items in this analysis therefore are not equal to the total incremental cost for generation expansion, which would include overall transmission and distribution, and certain other items. Since overall system costs not related to new project costs are not significantly affected by the new projects reviewed here, this partial analysis should accurately reflect the main differences between the KPLC plan and private power project.

a. Annual Cost Curves

In order to compare new generation capacity alternatives it is necessary to develop cost relationships for each type of capacity which reflect both capital and operation cost. It is also necessary to place costs which extend over a substantial period of time on a common footing. Cost relationships were developed for purposes of this report based on assumptions in the KNPDP, as revised in the Ewbanks-Preece report, and through communication with KPLC staff. The two basic cost components associated with each technology are annual capital cost (including fixed O&M costs) and annual operating and fuel cost.

Annualized capital cost used herein for analysis may be thought of as the cost of purchasing a unit of capacity on credit with repayment of principal and interest over the term of the loan. Variable cost depends on the number of hours the plant operates each year, and is made up of operating and maintenance and fuel costs. Since capital equipment is not 100% reliable, capital costs for equipment rated at a nominal capacity are adjusted to reflect estimated output after applying planned and forced outage rates. Inflationary effects have been removed from costs to allow comparison on a constant "dollar" basis. Only for fuel costs which are assumed to escalate in the future at a rate 4% per year higher than general inflation, have adjustments been made to reflect this differential. All discount factors and other parameters in this analysis are on a so-called "real" terms basis.

It was not feasible with the resources and data available for this analysis to run a system optimization model for KPLC to optimize plant dispatching and fully simulate a least-cost expansion plan for each case analyzed. Therefore in this report the basic least-cost expansion plan developed by ACRES International and KPLC, as modified by Ewbanks-Preece is used.

Figure III-1 shows the total capital plus variable costs for each new generation type as its varies with capacity utilization. This figure demonstrates cost differentials by usage rate. It can be seen that geothermal is the lowest cost resource above 80% capacity factor (utilization at rated capacity), while coal is less costly between 60%-80% capacity factor, with hydro (Sondu Miriu) being less costly below that level (but constrained by available water supply to only a capacity level of about 60%). The advantages of greater utilization of baseload capacity due to its lower costs can be seen with both geothermal and coal (whose costs exclude the port and handling infrastructure required). These resources are substantially less costly per kWh than combustion turbine or oil steam options when operated at high baseload capacity factors. Where generation is required either for standby or for intermediate or peaking duty only, it can also be seen that oil fired combustion turbine or other capacity would be more economic.

Hydroelectric generation alternatives are more complex to evaluate for several reasons. As the variable costs for hydro generation are very nearly zero, hydro unit cost shows very little sensitivity to the rate of capacity utilization. This can be seen for the Sondu Miriu and Sererwa options in Figure 1. (Also note the low maximum firm capacity levels for these two hydro options shown in the figure.) Hydro costs are generally very site specific, with a good hydro site likely to provide economic baseload energy. Where a site is poorer low water conditions cause energy and/or capacity to be constrained, or a low head may limit power output. Given the major impact of dry year conditions on hydro energy and capacity, hydroelectric generation often requires thermal back-up for reliability purposes, adding to real hydro costs. Due to the extensive hydro development in Kenya, additional hydro being contemplated is not necessarily more cost-effective than fossil alternatives.

b. Comparative Analysis Description

The basic economic comparisons provided in this report section consider three basic factors.

First, the relative cost for new additions is compared for the anticipated KPLC expansion plan (Base Case) versus private

Cost/kWh versus Capacity Factor

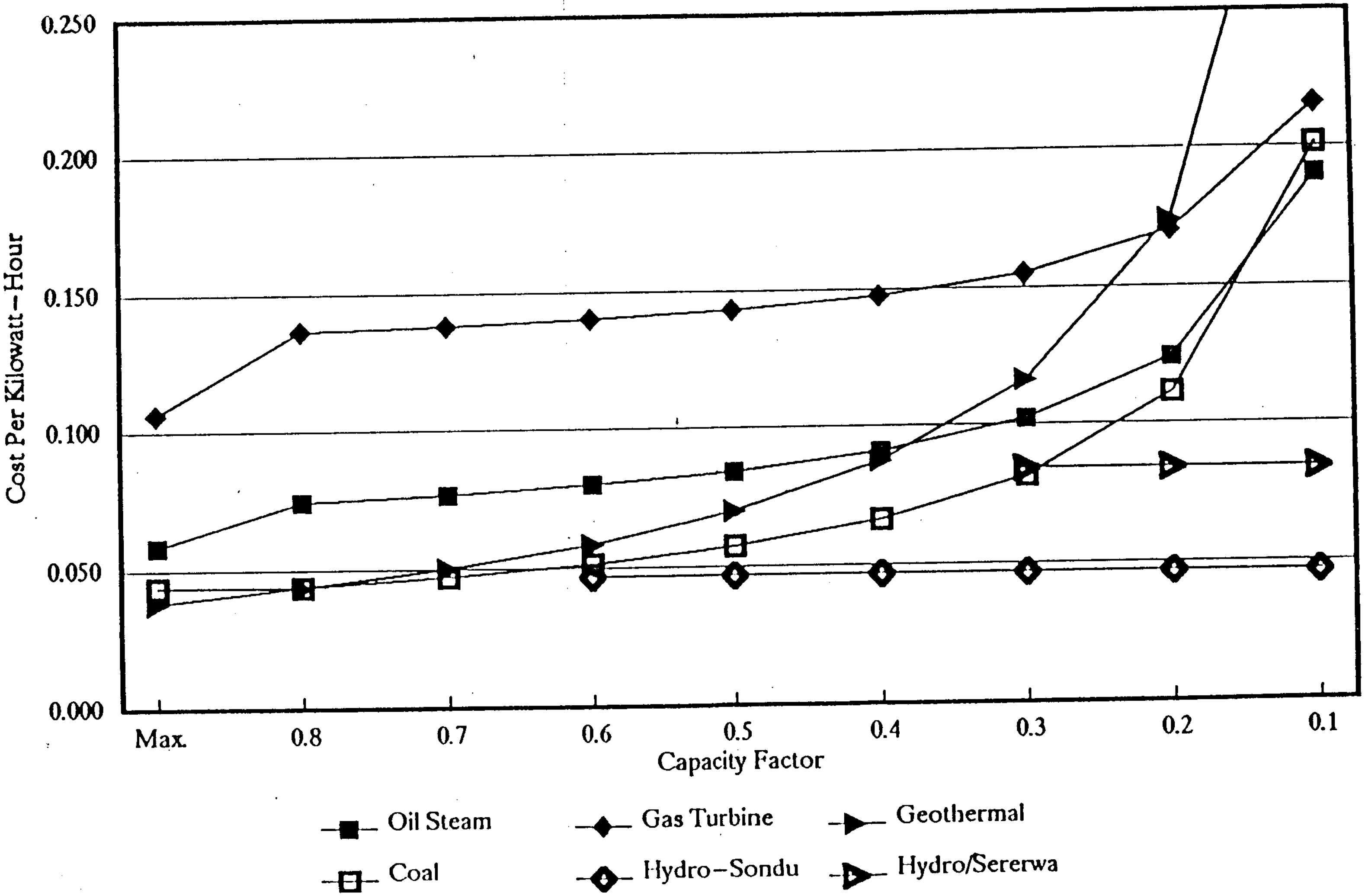

Table III- 5 The Kenya Power and Lighting Company -- Hydroelectric Resources

	Tana, Wanjii, Other	Kamburu	Gitaru	Gitaru 3	Kindaruma	Masinga	Kiambere	Turkwell	Sondu Miriu	Serevwa	Low Grand Falls	Magwagwa	Uganda
River	Various	Tana	Tana	Tana	Tana	Tana	Tana	Turkwell	Sondu	Arror			
Maximum Output (MW)	28	84	145	60	44	40	144	106	48	70	120	94.6	30
Firm Capacity (MW)													
Normal	16.8	81.5	144		44	26	129.3	99.8	31	70	88.3		30
Worst Case	16.8	64.0	144.0		44.0	12.9	92.0	85.7					22.5
Output Range (GWh's)													
Dry Year	138	287	565		133	135	625	294	82.7	18.4	482	276	
Average	153	351	688		163	166	735	372	277.6	157	594	334	203
Wet	174	478	912		228	237	983	448					

FILE: HYDRO

power alternatives in terms of annualized costs using the same discount factor (10%), in order to provide an approximation of relative economics.[1]

Second, a reduction in the use of oil-fired capacity and costs is calculated, to account for the benefit from new capacity "backing-out" less economic combustion turbine or oil steam generation.

Third, benefits from a reduction in potentially "unserved energy" (if any) due to the private power generation is included. Both ACRES and Ewbanks Preece have made estimates of the cost to end-users of going without electricity. These estimates are about Ksh. 15/kWh, and we have used this value, or $0.65 for sensitivity analysis.[2]

2. Comparative Analysis

a. KPLC Expansion Program

Shown in Table III-6 is the KPLC expansion program prepared as the Base Case for analysis in this report. The table presents, first, the initial capacity and energy balances or requirements. These are based on the system forecasts and assume no capacity additions beyond committed and facilities under construction. These figures form the baseline upon which additional capacity is added. This balance is not an expectation of the state of the system, only a representation of future requirements. Generation requirements in the Base Case include both station use and estimated losses, while capacity figures include a 15% reserve margin. Second, Table III-6 shows a revised balance after the planned KPLC expansion program, together with a summary of additions. Third, details of the expansion program are provided year by year to 2005/06, including size in MW, average cost per kWh, cumulative generation, and annualized cost. Fourth, total annualized cost is calculated and shown together with incremental cost per kWh provided for each year.

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1. In Section VI, KPLC plans versus private power alternatives are compared in terms of specific project financing assumptions, to develop estimates of actual cash flows.

2. The importance of costing and including unserved energy becomes apparent when we consider the near to intermediate term period if KPLC has difficulty in installing adequate new capacity. By measuring the cost of unserved energy we are able to provide estimates of the impact of energy shortfalls, as well as the benefit of a potential private power project which might reduce the risk of unserved energy.

Table III - 6 The Kenya Power and Lighting Company -- Expansion Plan Analysis
(Constant 1990 Dollars)

BASE CASE	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06
INITIAL CAPACITY/ENERGY REQUIREMENTS														
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)	(878.7)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)	(4,305.4)
BALANCE AFTER EXPANSION PROGRAM BELOW														
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(30.7)	(72.3)	(67.4)	(60.1)	(55.8)	(59.4)	(61.2)	(71.3)	(168.5)	(185.8)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	553.0	475.1	1,003.3	1,162.8	1,308.2	1,460.1	1,574.9	1,694.7	1,152.3	1,236.3
SUMMARY OF EXPANSION ADDITIONS														
CAPACITY ADDITIONS (MW)	30	90	122	184	215	232.9	287.9	347.9	407.9	462.9	522.9	577.9	637.9	692.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,601.4	1,758.4	2,534.2	2,954.7	3,375.2	3,817.0	4,237.5	4,679.4	5,099.8	5,541.7
KPLC GAS TURBINE ADDITIONS	30	60		30										
Cost/kWh ($)	$0.010	$0.010		$0.010										
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Total Annual Cost (000 $)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALL GEOTHERMAL ADDITIONS			32	32			55			55		55		55
Cost/kWh ($)			$0.039	$0.039			$0.039			$0.039		$0.039		$0.039
Max. GWH's (000's)			257	514	514	514	956	956	956	1398	1398	1840	1840	2282
Total Annual Cost (000 $)			$10,032	$20,064	$20,064	$20,064	$37,298	$37,298	$37,298	$54,533	$54,533	$71,768	$71,768	$89,002
Incremental An. Cost (000)			$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0	$17,235	$0	$17,235
					Hydro	Hydro	Hydro	Coal	Coal		Coal		Coal	
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60	
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021	
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52	2450.52
Total Annual Cost (000 $)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382	$86,382
Incremental An. Cost (000)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670	$0
BASE CASE Annual Cap. Cost	$2,007	$6,021	$16,053	$28,092	$40,781	$53,586	$97,030	$105,700	$114,369	$131,604	$140,274	$157,508	$166,178	$183,412
Base Variable Cost	$87,277	$113,023	$128,059	$125,776	$119,089	$129,301	$64,091	$58,164	$88,554	$89,346	$102,801	$103,907	$94,488	$96,761
Total Base Case Cost	$89,284	$119,044	$144,112	$153,869	$159,870	$182,887	$161,121	$163,863	$202,923	$220,950	$243,075	$261,416	$260,666	$280,174

Table III - 7 Basic Cost Assumptions for Analysis - Assumes Constant 1990 Dollars

Fuel/ Technology Number Description	<----------				New Generation				---------->
	Oil Steam	Gas Turbine	Coal Steam	Geoth. KPLC	Geoth. Private	Geoth. Private	Hydro Sondu	Hydro Sererwa	Hydro Magwagwa
					Base Case	Base Case	Miriu		
	Base Case	Base Case	Base Case	Base Case	(50 MW)	(20 MW)	Base Case	Base Case	Base Case
Size in MW's	60	30	60	32	50	20	49	70	94.6
Plant Capital Cost ($/kW	846	437	1018	2362	2192	2755	2271	1571	4695
Transmission Costs ($/kW	35.8	39.4	39.2	35.4	incl	incl	34.1	23.6	70.4
Exploration ($/kW)	0.0	0.0	0.0	236.2	incl	incl	0.0	0.0	0.0
Total (million $)	882	477	1057	2397	2192	2755	2305	1595	4765
Der.Local (KSH)	5072	2741	6078	13783	12604	15841	13253	9171	27401
Der. FOREX ($US)	709	415	878	2020	1678	2296	1763	1220	3646
Economic Life	25	20	25	25	25	25	40	40	40
Fixed O&M ($/kW yr)	12	14.04	21	20.6	27	50.5	5	5	5
Derated O&M ($/kW yr)	12.90	16.52	23.33	21.13	27.55	51.53	5.10	5.10	5.10
Total Derated Cost (by	1020	607	1312	2846	2436	3061	2400	1660	4961
Total Outage Rate)					-	0			
Forced Outage Rate	0.07	0.15	0.1	0.025	0.02	0.02	0.02	0.02	0.02
Total Outage Rate	0.14	0.23	0.2	0.1	0.1	0.1	0.04	0.04	0.04
Annual Operating Hrs	7534	6745	7008	8037	7884	7884	5783	2243	3531
Firm Capacity	60	30	60	32	50	20	31	18	0
Max Annual Generation						0			
(MWh's/year)	452,016	202,356	420,480	257,184	394,200	157,680	277,600	157,000	334,000
VARIABLE COSTS Fuel	HFO	IDO	COAL				31.7	17.9	38.1
Fuel Prices ($/GJ)	3.773	6.545	1.76	0			(Effective Capacity (MWs)		
Heat rate (kJ/kW hr)	11900	15000	12050	0					
Fuel Cost ($/kW hr)	0.045	0.098	0.021	0.000					
Escal rates	1.04	1.04	1.04						
Variable O&M ($/kW hr)	0.0015	0.00227	0.0018						

Capacity requirements in the Base Case are about 80 MW in 1992/93 and grow to a total requirement of 875 MW by 2005. Energy requirements grow at a similar rate, increasing from 121 GWh in 1993/94 to 4,305 GWh in 2005. Planned capacity additions to meet this demand (excluding Turkwell hydro plant soon to come on line), are about 740 MW. The after capacity expansion capacity balance shows that the planning reserve margin of 15% assumed in this report is not met after 1997/98, with reserves dropping to about 4% in 2005. Capacity additions will be made up of 120 MW of combustion turbines, 284 MW geothermal, 87 MW (effective capacity) of additional hydro, and 240 MW of coal. Total incremental costs vary by year due to capital and operating cost differences in generation capacity being added, with values dropping from $0.16/kWh in 1993/94 to about $0.06 in 2005/06. This picture reflects the fact that combustion turbine capacity must be added and oil capacity run more intensively in the short-run to meet loads before new baseload capacity can be brought on-line.

Total capital requirements in annualized amounts are shown in Table III-6, and demonstrate the tremendous increase in capital requirements of KPLC over the planning period. Requirements grow from about $2.0 million for capital and $90 million capital plus variable costs in 1992/93, to over $114 million for capital charges and $200 million in capital plus variable costs by the year 2000, reflecting the combination of combustion turbines, geothermal, new hydro and coal. These values which show the annualized costs for new capital additions, operating and maintenance costs and fuel costs, clearly represent a tremendous increase in revenue requirements.

b. Sensitivity Analysis on KPLC Base -- The Implications of Adding Geothermal Private Power

The purchase of additional or replacement capacity from private sources has a number of potential benefits for KPLC. These include tangible and measurable benefits such as possible lower prices for power, lower costs of development, shorter lead time and reduced workload for scarce KPLC project management personnel. Furthermore, numerous important uncertainties are reduced or risks shifted by pursuing private purchases. These include reducing the risks and financial burden of geothermal exploration, reducing the risk of capacity shortfalls due to new project delays, and reducing the risk of capacity or energy shortfalls from current or planned hydro generation. The sensitivity analysis below attempts to quantify and show the prospective costs to KPLC of these various tangible and intangible uncertainties. No attempt has been made to try and address the probability of occurrence for any of the above outcomes. It is likely that the best judge of the probability of any of the above eventualities will be KPLC staff themselves, and the purpose of this analysis it to provide a means for quantifying these judgments.

The sensitivities below involve a very large number of factors, years and assumptions. In order to try make this analysis understandable, while still meaningful, comparisons are shown in graphical form using percentage changes in average costs per kWh versus the original Base Case (4% growth forecast and 4% oil price escalation), for the various sensitivities. Average costs for a given year are the annualized capital cost for new generation for the plan for the respective year (total capital charges), plus total variable cost for that year, divided by total generation. Total costs, unserved energy costs, and total variable costs for each case can be found in the appendix.

Alternative Scenarios

Six basic scenarios or sensitivity cases were analyzed to provide a rough approximation of the implications for KPLC of various uncertainties and the benefits of private geothermal. This results in 60 basic cases, all of which are very briefly described here and summarized in the figures which follow. Details are given in a set of 4 tables in the appendix to the report. In all sensitivities the KPLC Base Case in Case 1 refers to the original KPLC expansion plan, that is, with the base forecast and oil price escalation assumptions. The other case comparisons give results of the changes in sensitivity conditions described, with the system adjusting only in operating terms, all other factors equal. The results therefore represent an estimate of the maximum impacts which might be observed under these scenarios.

Sensitivity Analysis:

In order to understand both the impact of various contingencies on the KPLC system and the prospective benefits of private geothermal development, we have done a common set of sensitivity analyses for each of the cases listed below. Cases refer to alternative forecast and oil price assumptions, with sensitivity analysis referring to analysis of various different capacity timing and cost assumptions.

Basic Assumptions for the different cases are as follows:

	Forecast Growth	Oil Prices Price Escalation	Base Increase (1992-93)
Case 1:	4%	4%	10%
Case 2:	6.7%	4%	10%
Case 3:	4%	6%	20%
Case 4:	6.7%	6%	20%

Case 1 consists of the basic sensitivity results compared under KPLC base case assumptions on forecast growth (Table III-2) and oil prices.

Case 2 consists of a set of sensitivities on a revised KPLC base case with a high forecast of load growth.

Case 3 again is a new set of sensitivities, this time with the original baseline forecast, but with oil price increasing more rapidly.

Case 4 shows the impact of sensitivities on a base case with both a high forecast and high oil prices.

The sensitivity assumptions which are examined in each case below are as follows:

Sensitivity Number:	Description:
Figure III-2	KPLC Base Case is modified by a delay in KPLC geothermal by 1 year. This forms the basic foundation for the analysis. Case 1-4 forecast and oil price assumption are then applied to this modified base period. Sensivitity analysis are shown for each case with the addition of 50MW of private geothermal, or alternatively 2x20MW of private geothermal.
Figure III-3	KPLC Base Case modified by a delay in KPLC geothermal by 2 years. Addition of 50MW of private geothermal, or alternatively 2x20MW of private geothermal.
Figure III-4	KPLC Base Case modified by a delay in KPLC hydro and coal additions by 1 year. Addition of 50MW of private geothermal, or alternatively 2x20MW of private geothermal.
Figure III-5	KPLC Base Case modified by a delay in KPLC hydro and coal additions by 2 years. Addition of 50MW of private geothermal, or alternatively 2x20MW of private geothermal.

Figure III-6 KPLC geothermal capital costs increased by 25%. Addition of 50MW of private geothermal to replace 32 MW of KPLC higher cost geothermal.

<u>KPLC Geothermal Delay.</u> The impact of a delay in KPLC's overall geothermal plan by 1 year and 2 years, respectively are evaluated in Figures III-2 and III-3, in terms of the percentage change from the Base Case. The impacts under the base forecast, high growth forecast, high oil price escalation (base forecast) and finally high growth together with high oil prices, are estimated. In the 1 year delay scenario (no other new KPLC capacity added), total costs rise by about 1.7% and average costs rise by about 2.4%. Adding a 50MW private geothermal project in the 1994-95 time period to compensate for this delay eliminates this cost increase and reduces average costs <u>below the base case</u> by 2.3% Alternatively, adding two smaller 20MW private plants, one in 1994-95 and the other in 1997-98, leaves total costs increasing about 1.9%, while raising average costs slightly less than with the delay and no private generation scenario.

Another important feature of this scenario is the reduction in the total available capacity to meet reserve margin requirements. With capacity to meet a 15% reserve margin goal requiring about 100-140 MW over peak during the period 1992-93 to 1999-2000, shortfalls range from a high of 122 MW in 1998-99 (providing virtually a zero reserve margin) to 27 MW in 1993-94 in this scenario. This contrasts with the Base Case with no delay, with a highest shortfall of 72 MW (providing about a 6.5% reserve margin). Adding 50 MW of private geothermal generation reduces the deficit in the delay case back to the base case level of about to 72 MW in 1997-98, and substantially lowers the average reserve deficit over the planning period.[3]

<u>KPLC Geothermal Delay -- High Forecast, High Oil Price and Combined High Forecast and High Oil Prices Cases.</u> The above picture would greatly change in the case of higher than forecast growth, that is, if growth is raised from 5.4% to 6.7%. In this case total costs of delay rise to 18% compared to the base case and average costs are 27% greater than the KPLC Base Case. The lower cost 50MW private geothermal plant in this situation lowers the total cost by 22% and shows only a 11% increase in average costs versus the KPLC Base Case. These conclusions result from two primary factors, first, the higher use of oil required to meet greater energy needs with a geothermal delay and high forecast, second, substantial unserved energy, and third, the lower cost of private geothermal versus KPLC geothermal plant.

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3. Deficit in this context refers not to an absolute shortfall in capacity to meet peak demand, but to a deficit in capacity required to meet a 15% reserve margin.

Figure III - 2 KPLC – Geothermal Plan 1 Year Delay

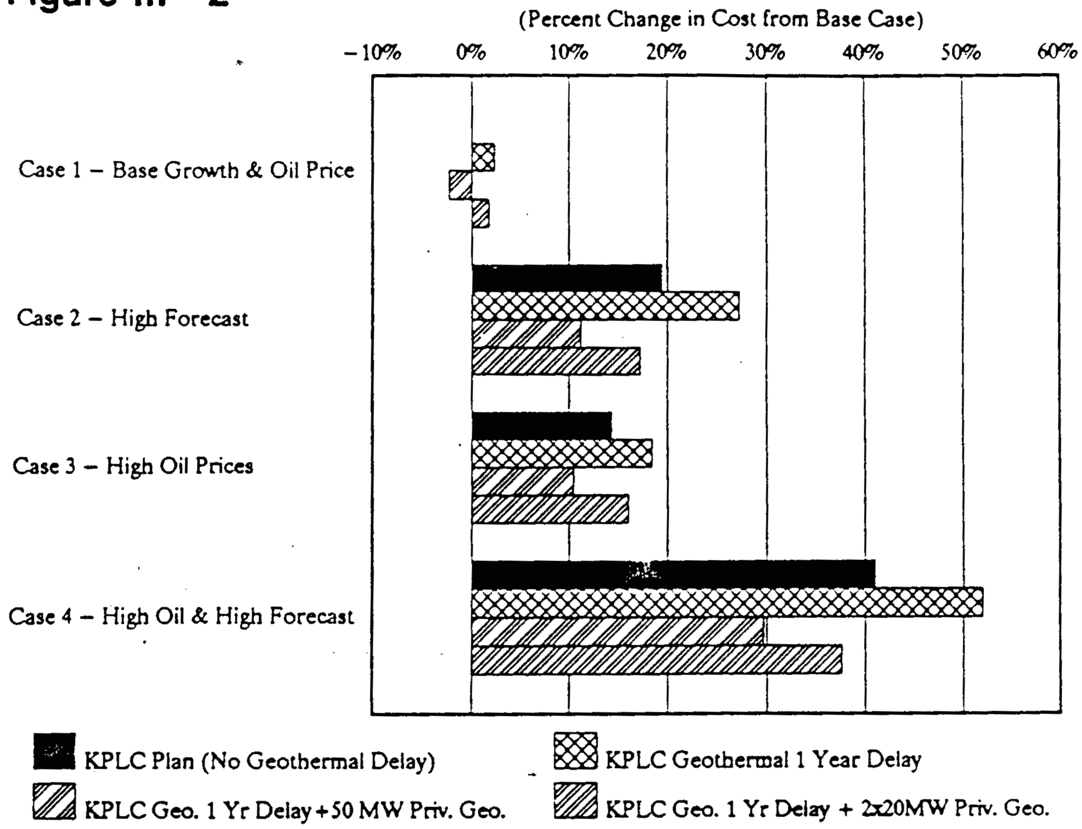


Figure III - 3 KPLC – Geothermal Plan 2 Year Delay

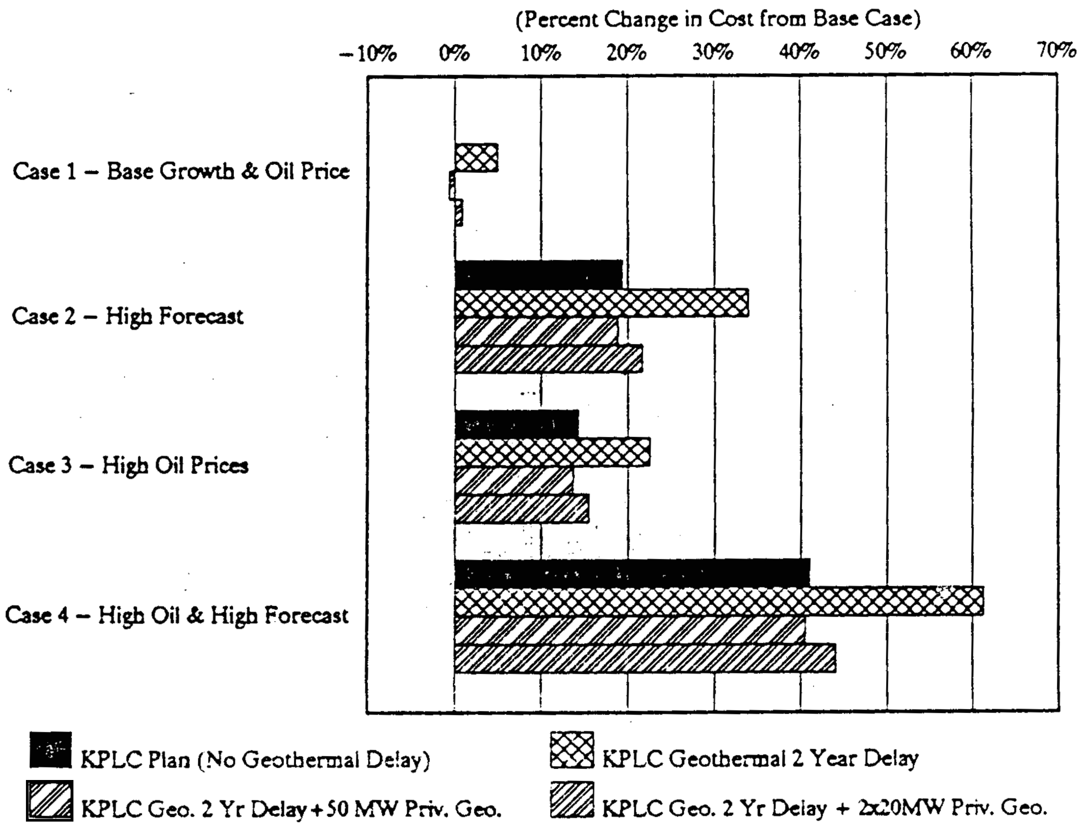


Figure III - 4

KPLC – Hydro & Coal Delayed 1 Year

(Percent Change in Cost from Base Case)

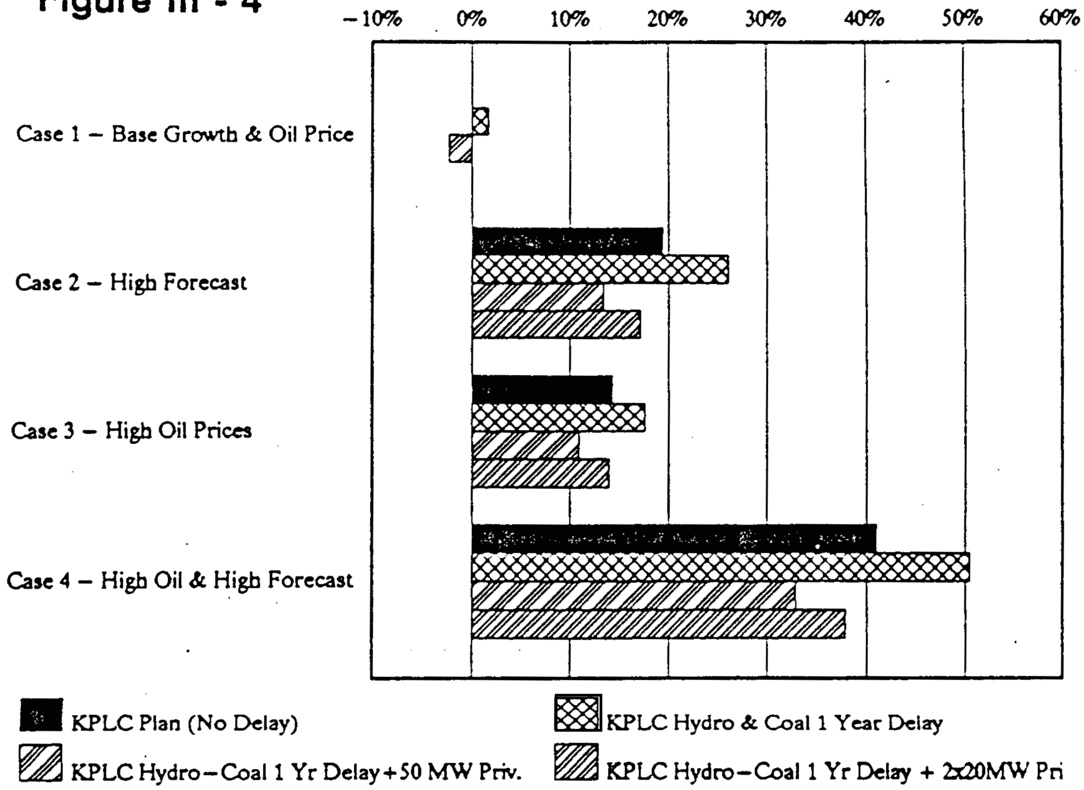
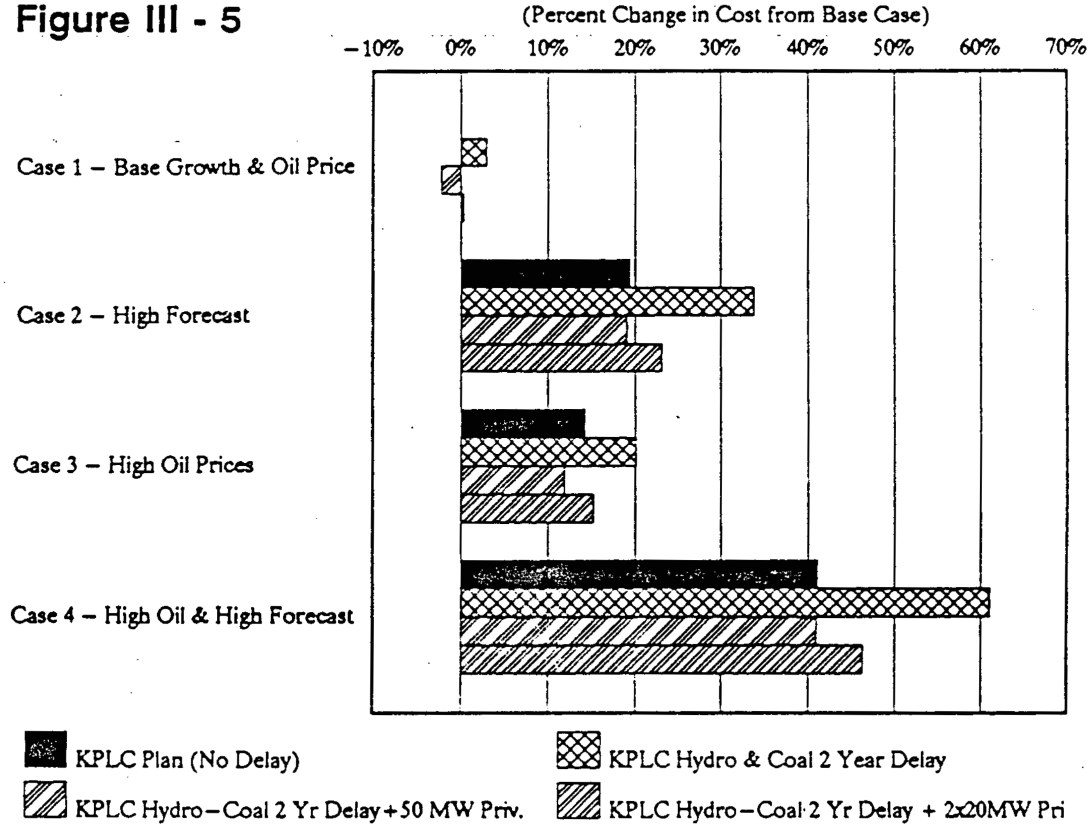


Figure III - 5

KPLC – Hydro & Coal Delayed 2 Years

(Percent Change in Cost from Base Case)



The impacts of higher oil prices with the base forecast are not so dramatic as with higher growth. Unserved energy is significant but only a small fraction of the high forecast case, and total costs rise only about 3% for the KPLC geothermal delay with no private geothermal, with average costs versus the KPLC Base Case rising by 18%. Again the addition of 50 MW of private geothermal significantly mitigates these higher costs. Total costs of the delay would be reduced by about 2.5% by adding private geothermal (50MW in 1994-95), and average costs would be only about 10% greater that KPLC Base Case.

Combining the higher forecast with higher oil prices produces a scenario similar to the high forecast case alone above, with similar relative benefits for addition of private geothermal (Figure III-2).

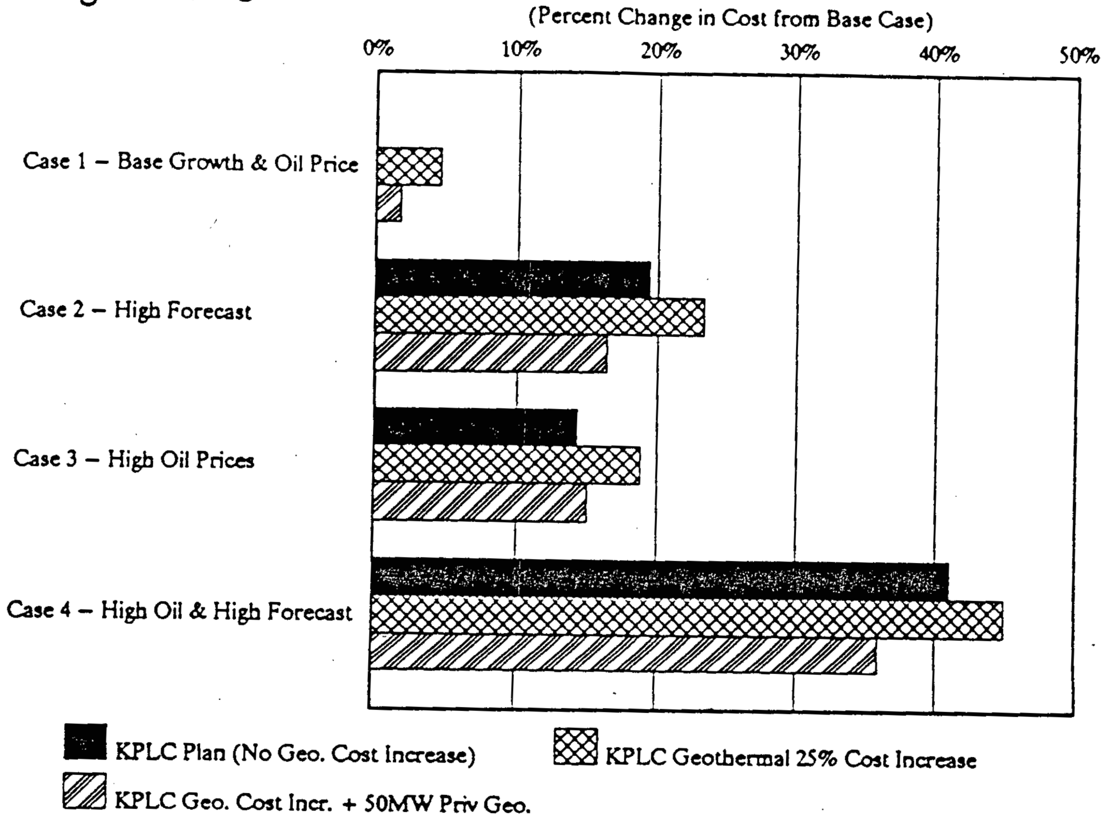
Figure III-3 shows the impact of a 2 year delay in KPLC geothermal and addition of private geothermal in two scenarios, the first case with 50MW added in 1995-96, and the second, two 20MW plants added, the first, in 1994-95 and the second, in 1995-96, respectively. The impacts of this case are similar in direction to the above 1 year delay case, however with the magnitudes of private power benefits increasing substantially.

<u>KPLC Hydro and Coal Delay.</u> In order to test the sensitivity of the results to a delay in other aspects of the KPLC Base Case, two scenarios of delay in hydro and coal capacity were examined. In the first, each hydro and coal addition is delayed by 1 year (Figure III-4), and in the second, hydro and coal are both delayed by 2 years (Figure III-5). Results are similar but costs increase are about one-half those of the above geothermal delay cases. Under the base assumptions on growth and oil prices, total costs rise by 1%, and average costs versus the KPLC Base Case rise by about 2%. With the additional of 50 MW of private geothermal, total costs are reduced to slightly below the KPLC Base Case. Results obtained in the higher growth and higher oil price cases, as shown in figure. Figure III-5 shows the results for a two year delay in the KPLC hydro and coal plans.

<u>KPLC Geothermal Cost Increase.</u> In order to understand the implications of higher than anticipated costs for KPLC geothermal on the system, a case was evaluated with an increase of 25% in KPLC capital costs. All other things equal, a 25% increase in KPLC geothermal capital costs increases total system expansion costs by about 5%, there is no change in unserved energy (no unserved energy), and reliability levels and ability to meet reserve targets do not change.

Figure III - 6

KPLC – Geothermal Cost Increase



The substitution of 50MW of private geothermal in the KPLC geothermal cost increase scenario, replacing 32MW of KPLC geothermal, produces substantial savings. Average costs remain above the no cost increase base case due to higher KPLC geothermal costs for remaining facilities, but overall the increase drops from 5% to 2.7%. The average system cost increase of 4.5% drops to about 1.7%. The impacts are more dramatic with high forecast scenario, with the total costs with private geothermal dropping by 6% from the KPLC Base Case with no cost increase. Average costs for the KPLC geothermal cost increase case with no private geothermal are 23% over the KPLC Base Case, versus a only a 16% rise with private geothermal substituting for 32 MW of KPLC capacity. These higher costs are heavily influenced by increased unserved energy in the high forecast case; which in the case of a 50MW private plant versus 32MW KPLC plant, are reduced considerably.

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Section IV -KENYA GEOTHERMAL PROGRAM - STATUS AND ISSUES CONCERNING DEVELOPMENT

A. INTRODUCTION

The objective of this section is to assess the geothermal resources of Kenya in terms of their size, logistics, development potential, and the time requirement and probable cost of exploring and developing them. This information is to be used in decisions regarding private investment in the Kenya geothermal industry, and in determining the terms and conditions of such investment.

This section is based both on original field work by the authors (McNitt and Koenig, of GeothermEx, Inc.), and on a review of published and unpublished work by others. Data on thermal manifestations and areas of youthful volcanism have been compiled and annotated, along with comments on the level of exploration previously achieved in each field or prospect. Estimates have been made of field or prospect area, depth and temperature. These estimates are based on the authors' experience in geothermal drilling in Kenya and elsewhere in the Rift Valley of East Africa (Ethiopia and Djibouti), and on experience in comparable geologic settings elsewhere.

From these findings, estimates of reserves have been made for each field or prospect. These vary in precision from order-of-magnitude for several poorly known areas to more-detailed for the Olkaria area and Eburru. Factors of topography and accessibility, distance from transmission lines, local markets, environment, and results of prior exploratory work have been considered, along with probable depth of drilling, possible drilling success rates and possible well yield, in a calculation of the cost of exploration and development. Where the estimate of reserves is considered sufficiently reliable, the total cost is converted into a cost per MW to develop.

The several fields and prospects have been ranked in order of attractiveness for future development. The ranking represents the authors' judgement as to where in Kenya investment in geothermal resources should take place during the remainder of this decade. Despite the experience of both authors in geothermal exploration and development, no warranty is offered or implied in the rankings presented herein.

B. GEOLOGIC SETTING OF THE KENYA GEOTHERMAL AREAS

Geologically, Kenya consists of a Precambrian platform of metavolcanic and metasedimentary rocks, which regionally has been domed and uplifted, and both covered by younger rocks and sediment, and broken by younger structures (Figure IV-1). Precambrian rocks do not crop out in the eastern coastal plain or in the Rift Valley, but are exposed in the walls of the Rift and across much of central and western Kenya. Paleozoic rocks are present only in the southeastern coastal plain. Mesozoic rocks are more widespread, being exposed in the northeast and northwest as well as in the southern coastal plain.

However, the cover over the Precambrian basement is mainly of Cenozoic age: Miocene through Holocene sediment is distributed across the lowlands of eastern Kenya, and Oligocene through Holocene volcanic and sedimentary rock and unconsolidated sediment is present in the highlands of central and western Kenya and in the Rift Valley.

The Rift Valley (also known as the Eastern or Gregory Rift) is a broad trench that runs N-S across western Kenya, extending on the N into Ethiopia and on the S into Tanzania (Figures IV-2 and IV-3). The Rift escarpment is well-defined in some segments, and more diffuse in others. Similarly, its width varies from perhaps 25 km at the narrowest to over 100 km in its more diffuse segments. Not only are the Rift margins fault-bounded; faults of general N-S trend cut the Rift floor in numerous places, sometimes as major sub-parallel swarms and occasionally as discrete individual fractures (Figure IV-4). This has resulted in creation of numerous blocks bounded on both sides by faults (horsts and grabens), or only on one side (half-horsts and half-grabens) with corresponding block rotation.

A second rift, the Kavirondo Rift, trends E-W nearly normal to the Gregory Rift in western Kenya to Lake Victoria (Figure IV-4). The Kavirondo Rift cannot be traced across the lake into Uganda.

Volcanism, and associated lacustrine and alluvial sedimentation, has been very intense within and on the margins of the Rift. This has been explained by postulating that the generation of magma near the base of the crust, beginning late in Oligocene time in response to movement of the African plate, in turn caused doming of the Precambrian crust, rifting and volcanic eruptions on a massive scale. Lakes formed in downdropped basins and behind volcanic dams. Enormous quantities of lava, ash and sediment accumulated within the rift to depths ranging from a few tens of m on the Rift margins to several km within deeply downfaulted sections.

Topographic elevation also varies along the Rift Valley floor, with the topographic high located in the vicinity of Lake Naivasha (elevation about 1.8 km), and with elevations decreasing by as much as 1.2 km to the S at Lake Magadi and 1.5 km to the N at Lake Turkana. The elevation difference is explained as being related to magmatic inflation of the Precambrian dome. Relief along major fault escarpments reaches or exceeds 1,000 m in several locations.

Thickness of fill within the Rift Valley has been calculated from gravimetric and seismic refraction surveys, and from geologic map interpretation. The fill varies from a calculated maximum of about 6 km beneath Lake Naivasha to minima of about 2 km beneath Lake Magadi and 1.5 km beneath Lake Bogoria. P-wave velocities suggest that Precambrian basement and Tertiary mafic intrusive rocks underlie the Rift Valley fill. Although intrusions and local magma chambers are believed to exist (especially beneath certain active volcanoes, as discussed below), evidence is moot regarding a possible "axial intrusion" running the length of the Rift Valley at a few km in depth.

However, the foregoing does not explain why many of the major Quaternary volcanoes of Kenya lie outside the Rift Valley (Figure IV-5), at distances of up to 200 km. Diagrams showing the variation in chemical composition of the volcanic rocks versus time of eruption and location relative to the Rift Valley have been prepared (Figure IV-6) in the attempt to explain this fact, without arriving at any convincing explanation.

What is demonstrated is that the more silicic volcanic rocks (rhyolite, comendites, pantellerites and their tuff and ash equivalents) are found most typically in the vicinity of the topographic center of doming in and adjacent to the Rift Valley. The more alkaline (nephelinite, trachyte, phonolite) and mafic (basalt) volcanics are distributed at the margins of the dome and beyond. Worldwide, there is a generalized association of producible geothermal systems with less-mafic or more-silicic volcanism, although this relationship is not without exceptions.

Several of the well-known volcanoes of latest Tertiary or Quaternary age are shown on Figure IV-7, although several large eruptive centers, and smaller cinder cones, domes and maars too numerous to list do not appear. Thermal manifestations (springs, fumaroles, steaming ground, etc.) are associated with many of the major volcanic centers, such as Silali, Paka, Longonot, Eburru and Suswa. However, many major volcanic centers, such as Shombole, Mt. Kenya, Rangwa and Lenderut are not known to have hydrothermal manifestations; these tend to be older than the fumarolically active volcanoes, and often are outside the main Rift Valley. Also, a very large number of thermal areas are not obviously associated with any major volcanic center, such as Lake Bogoria, Lake Magadi, Arus and Lorusio. These tend to be locally low points of elevation, and may represent outflow of thermal waters from reservoirs elsewhere.

In general, the principal thermal areas are found within the Gregory Rift. However, others are associated with the Kavirondo Rift (Homa Bay area) or are outside of the Rift Valley system (for example, Masamukye, SE of Nairobi, and Mwananyamala, S of Mombasa). In general, again, the areas of known fumarolic activity, steaming ground and boiling springs are within the Rift Valley; those outside of it exhibit lower surface temperatures and/or appear to have lower temperatures at depth.

Both volcanic and seismic activity continue in the Rift Valley. Historic eruptions are reported for Teleki's Volcano, just S of Lake Turkana (shown as Barrier on Figure IV-7), most recently in 1921-1922; Andrew's Volcano, just to the S of Teleki's, appears to have been active within the past 100 years. Emuruangogolak has been dated by ^{14}C radiometry to have been active approximately 300 years before the present, and may have erupted as recently as the end of the 19th Century.

Silali, to the S of Emuruangogolak, may have been active during the past few centuries. Paka volcano, closer to Lake Baringo, probably was active within the past few thousand years, and possibly within the past few centuries. It is located in the northern Rift Valley about midway between Lake Baringo and Lake Turkana.

Longonot, E of Olkaria, has yielded cultural evidence of an eruption sometime between 1858 and 1868. Suswa, S of Longonot, probably had its most recent eruption within the past 300 years. There is evidence that a magma chamber exists beneath Suswa, as well as beneath many of the other historic or quasi-historic volcanic centers. Shaitani and/or Chaimu, basaltic volcanoes located near the NW corner of Tsavo West National Park in southeastern Kenya, outside the Rift Valley, reportedly erupted in the 1850s, perhaps in 1855.

Several other major volcanoes, as noted above, are fumarolic; and many of these, including Menengai, yield evidence of eruption within the Holocene Epoch (past 10,000 years), and possibly within the last few hundred years. Basalt flows of the Elmenteita area, S of Menengai, fall into this category also. In addition, numerous isolated cinder cones, domes and basalt lava flows probably are latest Pleistocene and Holocene in age; and some may have erupted, unreported, in historic time.

Faulting probably has occurred in several major episodes to form the Rift Valley, and then to break the Valley floor. Seismic activity continues, but is irregular in distribution both geographically and in time. Some very youthful volcanic features show fault offset (the slopes of Paka volcano, for example). This suggests fault movements into historic time. However, most investigators have concluded that seismicity (and therefore fault movement) is greatly diminished from Plio-Pleistocene time; and that most of the prominent, scarp-forming faults are inactive. However, seismic activity and fault offset can be expected to continue locally. The Kavirondo Rift is believed to be seismically inactive (a so-called "failed" rift).

C. HISTORY AND STATUS OF GEOTHERMAL EXPLORATION AND DEVELOPMENT IN KENYA

During British colonial times, reconnaissance studies of geothermal manifestations were carried out by the Kenya Geological Survey. These studies noted the presence and temperature of thermal springs and fumaroles, and related their distribution to faulting and volcanic activity within the Rift Valley. In the 1930s speculation began on possible commercial utilization of the fumaroles of the Lake Naivasha region for electric power generation.

At Eburru, beginning in the early '40s, steam from low-pressure fumaroles was condensed as a fresh-water source in an otherwise waterless volcanic upland. Steam also was used in small operations to process pyrethrum flowers as a source of high-quality natural insecticide. During the '40s and '50s several wells drilled for water in various parts of the Rift Valley encountered hot water or steam.

Between 1956 and 1959, as a result of further geological and geophysical reconnaissance in the Rift Valley, emphasis became focused on Olkaria (then spelled Orgaria). Beginning in 1956 and continuing into 1958, a consortium of private investors in Kenya and Great Britain, including Power Securities Corporation Limited and East African Power & Lighting Co. Ltd. (EAP&L), drilled two exploratory holes within a few km of what is now the Olkaria production field. Hole X-1 went to about 500 m and encountered temperatures over 120°C before being suspended. Hole X-2 reached temperatures over 200°C by 940 m. Despite repeated efforts, the wells could not be brought into sustained production for testing, and the project was abandoned.

In the mid-1960s, further geophysical surveys of the Rift Valley between Lake Bogoria and Lake Magadi again drew attention to the geothermal potential of the region. Anomalous areas of low electrical resistivity had been mapped previously at Olkaria, Eburru and elsewhere. The Olkaria anomaly covered between 50 and 100 km^2 in area. Based on this renewed interest, the Government of Kenya requested United Nations assistance in 1969 for a geothermal exploration project. The project (KEN/70/525) began in October 1970, with EAP&L (a parastatal organization) and the United Nations Development Programme (UNDP) named respectively as counterpart and executing agencies. The senior author of the present report, Dr. J. R. McNitt, was appointed project manager by UNDP.

Geological, geochemical and geophysical surveys were carried out at various scales across an extensive zone between Lake Magadi and a point N of Lake Bogoria, but centering on Olkaria, Eburru and Lake Bogoria. Simultaneously, well X-2 was cleaned out and brought into sustained production (1972), discharging steam. Based on these surveys and tests, and calculations of the economics of drilling and development, Olkaria was selected for exploration drilling and development.

Drilling at Olkaria began in 1973; by 1976, when the first stage of the UNDP project was completed, 6 wells had been drilled. Well OW-2 was the first to indicate commercial productivity. Depths of the 6 wells ranged from 900 to 1,685 m. Production zones were identified and tested between 650 and 900 m and between 1,100 and 1,300 m. Steam was produced, with an increasing water percentage from deeper holes and from holes farther to the north. Temperature of the production zone was found to be approximately 245°C, with higher temperatures found in the deeper and water-saturated zones. Teams of British and Icelandic consulting firms (including Merz and McLellan, and Virkir) determined by testing and data analysis in 1976 and again in 1977 that the field was suitable for commercial power generation.

Total UNDP expenditure under KEN/70/525 was approximately US $1.5 million. EAP&L expenditure is not known, but may have been approximately equal in amount.

The World Bank was then asked by the Government of Kenya to finance construction of the initial 30 MW power plant, 22 km of 132 kv transmission lines, purchase of a drilling rig, completion of the development wellfield, construction of auxiliary facilities, and purchase of support materials. Late in 1979, an agreement was reached under which the Bank agreed to lend US$40 million of the US$89 million required to construct the two 15 MW power plants and other facilities at Olkaria. Terms included a 20-year loan period, 5 years of grace, and 7.95% annual interest. The Commonwealth Development Corp. agreed to provide US$20 million, with the remainder coming from Kenya Power Company (KPC), a subsidiary of EAP&L, and from the Government of Kenya. KPC was appointed as the executing agency. Consulting firms from New Zealand, the UK and Iceland were employed in various capacities regarding drilling, resource assessment, power plant design and construction supervision.

At that time, 11 holes had been drilled. The first 15 MW plant went on-line in June 1981. By that time, 19 wells had been drilled, of which 14 wells were capable of supplying 34 MW. Various consulting reports had estimated reserves to be 170 MW within a 12 km^2 area, and up to 1,400 MW within the 100 km^2 greater Olkaria area.

Under the terms of an internal agreement within the Government of Kenya in 1979, the Ministry of Energy was given responsibility for all geothermal exploration and exploratory drilling within Kenya. EAP&L was given responsibility for development and operation of the Olkaria field and of any field subsequently discovered. EAP&L in turn delegated responsibility for Olkaria to its subsidiary, KPC.

Assistance in geothermal exploration/development also was provided by the Japan International Co-operation Agency (JICA) under a bilateral agreement signed by the Governments of Kenya and Japan in November 1979. The Ministry of Energy was appointed as the counterpart agency of JICA. Eburru, which along with Lake Bogoria and the Menengai and Longonot volcanoes had been identified in the UNDP project as highly attractive, was selected. Geological, geochemical and geophysical surveys were begun; however, the project was stopped late in 1981 before the anticipated completion period of 3.5 years. Temperature-gradient holes were not drilled, despite having been planned.

Planning for a follow-on geothermal exploration project began between the UNDP and the Government of Kenya in 1979. The geographic area and scope of work were decided upon after a reconnaissance assessment by the present junior author, J. B. Koenig, late in 1980. The project, KEN/82/002, was approved in May 1982; after an offer of supplementary technical assistance from the Government of Italy was accepted by Kenya in 1984, a budget of US$4.8 million (US$3.4 million from UNDP and US$1.4 million from Italy) and Kenya Sh 28,000,000 (approximately US$2 million at 1984 exchange rates) was approved. The UNDP and Ministry of Energy were appointed as executing and counterpart agencies.

In 1985, the Government of Kenya also entered into a bilateral agreement with the Government of the United Kingdom, under which the Overseas Development Assistance would provide £575,000 (approximately US $700,000 at 1985 exchange rates) for geological and related surveys of the central part of the Rift Valley. Work was to proceed simultaneously with the UNDP-Italy project. In practice, a group from the British Geological Survey conducted geological mapping and fluid geochemistry and isotopy in the Longonot-Suswa region, and regional hydrology of the Lake Naivasha-Suswa area; and a contractor provided by the Government of Italy (Geotermica Italiana) performed geological, geochemical and geophysical studies of the Menengai-Bogoria region, and Italian and Icelandic firms did geophysical surveys in parts of the Longonot-Suswa area.

The second 15 MW power plant was commissioned by Kenya Power and Lighting Co. Ltd. (successor to EAP&L) in December 1982; and the third 15 MW unit was placed on-line in March 1985. Turbine-generators and associated electrical equipment were supplied by Mitsubishi Heavy Industries Ltd. Twenty-six wells had been drilled to supply the 45 MW production, of which 22 wells were in use. Yield per well averaged just over 2 MW.

Drilling at locations elsewhere in the Olkaria region began in the early '80s. Discoveries of potential commercial importance were made in northeastern and western Olkaria. By 1986, 13 wells had been drilled, of which 5 were considered to be commercially productive. Higher temperatures (over 300°C in several wells) were encountered in holes of 1,800 to over 2,400 m in depth, indicative of a water-dominated system. Drilling proved difficult in many cases, with several wells being suspended because of drilling or completion problems.

At the same time, pressure declines were observed in the Olkaria production wells. Principal areas of upflow from the deep reservoir were identified in NE and W Olkaria, and the Olkaria production field was identified as an outflow zone. This led to revisions of the Olkaria field model, calculation of requirements for make-up drilling, dedication of an additional area of proven reserves for the 45 MW power plant, and the planning for expansion of electric power production into NE Olkaria.

In 1984, the World Bank and the Government of Kenya signed IDA Credit 1486-KE, which provided for exploratory drilling of up to 8 wells at Eburru and further drilling in the Olkaria region. This exploration project was funded by the Bank at SDR 23 million (US$24.5 million at the May 1984 exchange rate), with Kenya Sh equivalent to US$9.8 million also to be provided by KPC and the Ministry of Energy. Although the Ministry of Energy had been given responsibility for exploration outside of Olkaria, KPC was given responsibility for the Eburru drilling. New Zealand project consultants (GENZL) were employed by KPC.

Subsequent to this, severe problems in drilling, and other extensive project delays, and overspending in various project categories, led to a reassessment of project goals and operating methods. A subsequent IDA credit was agreed upon in 1988 between World Bank and Government of Kenya. This provided for reallocation of approximately US$3.2 million from Credit 1486-KE to the new Credit 1973-KE to allow the delayed Eburru drilling to proceed, plus funds for a new IDA loan to continue drilling and appraisal of the Olkaria region, along with infrastructural support. Because of (a) subsequent reallocations between Credits 1486-KE and 1973-KE, (b) fluctuations in the dollar exchange rate of the SDR, Deutschmark (drilling contract so denominated), and Kenya shilling, and (c) allocation of part of the Credit to non-geothermal activities, no dollar amount for Credit 1973-KE is provided herein.

Late in 1986, Acres International Limited presented a report, "Kenya National Power Development Plan, 1986-2006", under funding provided by World Bank and UNDP. This plan concluded that geothermal power represented the least-cost base-load alternative available to Kenya for power generation through the year 2006. It recommended that 280 MW of new geothermal generation be added, beginning with 30 MW each in 1994 and 1995, and continuing with 55 MW in 1998, 2001, 2003 and 2005. Specific sites were not identified, but it was implied that the majority of this new geothermal generation would be installed in the Olkaria region and Eburru.

Although the Acres report has not formally been adopted by the Government of Kenya, KPLC has acted informally to begin implementation of its geothermal recommendations. A feasibility study by Ewbank Preece Limited was completed in December 1989 for the northeast Olkaria block, in which it was concluded that two 32 MW power plants were economically and technical feasible for commissioning in 1992 and 1993, and that the potential exists for a third 32 MW power plant in the same area.

Work was extended under UNDP project KEN/82/002 into 1989, with additional financing. Recommendations submitted in 1989 by the principal consultant, Geotermica Italiana, included the drilling of 6 to 8 exploration wells in an area immediately N of Menengai volcano (Olongai-Olobanita caldera complex), and in the area S and SE of Olkaria field (mouth of Hell's Gate canyon and on lower flanks of Longonot volcano) to depths of 2,000 m or greater. If drilling and testing confirmed the existence of an exploitable reservoir, it was recommended that a non-condensing power plant be installed on one, two or 3 wells to demonstrate the technical and economic feasibility of large-scale development. Although size of the demonstration power plant was not specified, 5 MW was discussed.

Since that time, there have been extensive communications between the Government of Kenya, the UNDP and the Government of Italy regarding possible bilateral (Kenya-Italy) and trilateral (Kenya-Italy-UNDP) projects. The sum of US$25 million was discussed, although no firm cost figure was agreed upon. Most recently (February 1990), an Italian consortium of Ansaldo GIE (turbine manufacturer), Geotermica Italiana (resource consultant) and SICOM (driller) has proposed to KPLC that they be given a contract by KPLC in the amount of ECU 26.9 million (approximately US$33 million) and Kenya Sh 75.4 million (US$3.4 million) for drilling at either the Menengai or Longonot locations, followed by installation of a 5 MW turbine-generator. No Italian government financing was offered, but it was inferred that such support would be forthcoming following signing of a commercial contract between KPLC and the Italian group.

In 1988, the Government of the United Kingdom granted a 3-year, £833,000 (US$1.35 million at 1988 exchange rates) extension of its cooperative program, for detailed geological mapping and fluid geochemistry in the volcanic terrain of the northern Rift Valley by BGS. Work has focused on the trachytic Korosi, Paka, Silali, Emuruangogalak and Namarunu volcanoes. It has in part utilized results of an earlier (1981-1984) cooperative geologic mapping project involving BGS and Kenya Mines and Geological Department (KMGD) scientists. Results of this earlier work were published in 1987 and 1988 by KMGD; the current results are to be released in late 1990.

UNDP presently proposes to conduct environmental assessments of geothermal development in the greater Lake Naivasha region, and to provide miscellaneous support to the Ministry of Energy program. Approximately US$500,000 may be authorized.

In 1987, in response to continued operational problems at Olkaria, KPC signed a technical assistance agreement with Petro-Canada International Assistance Corporation (PCIAC). Under this grant agreement, PGIAC provided Canadian advisors in drilling and wellfield operating for a period of up to 3 years, for help at Olkaria. GENZL's role was restricted to Eburru drilling. The agreement was valued at Kenya Sh 38.6 million (US$1.9 million at 1987 exchange rates), and subsequently has been augmented and extended until at least early 1992. Drilling performance at Olkaria has improved significantly.

An Act allowing for the licensing of private companies to participate in exploration and development of Kenya geothermal resources was approved in 1982. Under terms of that Act and Rules gazetted in 1990, companies from the United States and other countries have expressed interest in investment in the Kenya geothermal industry. Unocal Corporation, beginning early in 1988, conducted a reconnaissance assessment of geothermal prospects. Unocal informally has requested exclusive permission to explore Paka, Menengai and Lake Bogoria prospects; no action is known to have been taken by the Government of Kenya in response. A consortium of American companies, including GeothermEx, Inc. and The Ben Holt Company, have held discussions with Magadi Soda Company Ltd. (a unit of ICI) regarding development of off-grid geothermal electric power to supply Magadi Soda's mining and processing operations at Lake Magadi.

Additionally, private and quasi-governmental companies in Iceland, Italy and Japan, and possibly elsewhere, have submitted unsolicited proposals to KPLC and/or Ministry of Energy regarding sale of goods and services to the Kenya geothermal program. The recent Italian proposal was discussed above. Mitsubishi Heavy Industries has suggested that KPLC request assistance from Overseas Economic Cooperation Fund (OECF) of Japan in arranging financing for the planned two 32 MW power plants at NE Olkaria. No action has been taken by KPLC.

The World Bank has initiated discussions with KPLC regarding a possible future IDA credit, to cover the two 32 MW plants, feasibility determinations for geothermal power plants at either W Olkaria or Eburru, exploration of an additional prospect, and technical and infrastructural support. Such a credit might be granted in mid- or late 1991 or early 1992. Value could exceed US$100 million.

Drilling at Eburru, under World Bank financing, finally began in 1989. Results of the first 4 wells have not been as encouraging as KPLC and its consultants GENZL had anticipated. Drilling of two more wells is underway now at Eburru. By contrast, the results of drilling at Olkaria production field, and at W and NE Olkaria have surpassed expectations. More than half the wells needed for the two 32 MW plants at NE Olkaria have been drilled; and make-up wells sufficient for several years of operation have been completed at the main Olkaria field.

Geoscientific research continues in the Rift Valley. This includes student theses, oil exploration surveys (no oil or gas has been found in Kenya), and scholarly research into crustal structure.

From 1970 to date, approximately US$170,000,000 (in dollars of those years) has been spent in geothermal exploration and development by all parties, including the Government of Kenya and its agencies, the UNDP, the World Bank, the Governments of Italy, Japan and the UK and other governments, and miscellaneous research agencies and private companies. Of this amount, perhaps one-quarter has been spent in Kenya on local equipment, supplies and services. The largest overseas expenditures have been to purchase goods and services in:

Japan - turbine-generators and related equipment; exploration services; vehicles and other equipment

New Zealand - exploration and engineering services; management services; training services

Belgium - drilling contracts

United Kingdom - engineering services; miscellaneous supplies and equipment

Iceland - engineering services; individual consultancies; training services

Italy - exploration services; training services

Perhaps 3% has been spent in the United States for wellfield services and supplies, individual consultancies, and scientific equipment.

If, indeed, some 280 MW of geothermal electricity will be added by 2005, a further expenditure of at least US$600 million will be required for exploration, drilling, field development, power plant design and manufacture, and construction, as well as for purchase of equipment and supplies, and for training and infrastructural support. The percentages to be derived from international lenders and donors, the Government of Kenya and its agencies, and private investors cannot be estimated closely.

D. THE BASIS FOR RANKING GEOTHERMAL PROSPECTS

1. Background

As described elsewhere, Kenya has extensive geothermal potential, estimated at several thousand MW for 30 years. Few of these geothermal areas have been explored in detail, although geological reconnaissance, cataloguing of thermal manifestations, and fluid geochemistry has been accomplished at many prospects. Reconnaissance or detailed geophysical surveys (principally gravity and electrical resistivity) have been run in the region between Suswa and Lake Bogoria. Drilling of geothermal wells has been accomplished only in Eburru and the greater Olkaria area.

Therefore, a wide variation exists in the detail of exploration and level of knowledge for each prospect area. As the levels of knowledge increase through time, the ranking of each prospect can be expected to change, both absolutely and relative to other prospects. The ranking methodology must therefore be capable of processing unequal quantities of information on a common basis, so as to provide statistically reasonable projections that can be tested and revised in the future.

Further, the conditions of accessibility, the proximity to transmission lines and to market, and the technical complexity or degree of risk to be expected in developing the resource affect project cost and ease of financing, and ultimately help to determine which fields are developable. It would therefore be incorrect to establish ranking solely on the size of the resource. The present methodology attempts to utilize all the factors described herein.

2. Types of Assessment Methodologies

The simplest method of assessing a resource is by analogy. For example, calculations of MW per km^2 of field routinely have been made by KPLC's consultants, on the basis of (a) size of the measured surface electrical and geochemical anomalies, (b) experience with geothermal fields elsewhere in comparable geological settings, and (c) inferences regarding data quality or reliability of the surface anomalies. Results typically are presented as a single best-estimate, or occasionally as an upper and lower estimate, without a percentage probability for any estimated value. This method may be used before or after initial well drilling; it has been used at both Olkaria and Eburru. Pre-drilling estimates made at Eburru by this method now seem to have been unrealistically high.

Another method, often used after the initial round of drilling has been accomplished, but before there is an extensive history of well testing or production, involves calculation of the field volume, along with an estimation of the recoverable energy within that field volume. Volumetric calculations depend upon a knowledge of the distribution of field depth, thickness, areal extent, permeability and temperature, as well as fluid chemistry, and chemical and physical constraints on extraction. Here again, a single value or an upper and lower value typically are presented, without any calculation of the probability that the value(s) are correct. Volumetric calculations were utilized by the U.S. Geological Survey in a series of published assessments of United States geothermal reserves, including numerous prospects that had not been drilled. Subsequent drilling resulted in modification of many of these values.

There is inevitably some uncertainty over what value or range of values to assign for a given reservoir parameter in a volumetric calculation. To minimize this, reserves can be estimated in a probabilistic way, using a Monte Carlo simulation.

Even where there has been no drilling (or no significant drilling), Monte Carlo simulation can be done. The range and distribution of possible values is estimated for each critical parameter. The values of these uncertain parameters are sampled randomly, perhaps 1,000 or 10,000 times, using a specially designed Monte Carlo simulator. The results are used to calculate recoverable energy, as in other volumetric analyses, and are presented in terms of the percentage probability of any numerical value of reserves.

The advantages of this method are that it (a) provides a common basis for evaluation of prospects for which there is little information, as well as fields for which extensive well-test data are available, and (b) it allows a quantification of risk associated with exploration or development.

The principal disadvantage is that there is a tendency to use the same or similar values of reservoir parameters having to do with depth, thickness and permeability for all unexplored prospects, thus resulting in similar (or identical) reserve and probability values. A second difficulty is that a spurious level of confidence may result.

Once there are extensive well-test data or production histories, it is reasonable to perform numerical simulation modeling. This involves constructing a detailed 3-dimensional gridded model of the reservoir and, through multiple iterations, achieving a match between the model and the well-test or production data. The model thereupon can be used to forecast field operating conditions, operating costs, reserves and field life under various scenarios. This has been done for the main

Olkaria field by KPLC's UK and Iceland consultants. Well-test data still are insufficient for meaningful numerical simulation modeling of West Olkaria and Eburru. Well-test data are lacking for all other Kenya geothermal prospects.

After serious consideration, it was decided to use the simplest basis of comparative evaluation, analogy. There are insufficient data for many prospects of potentially large size, especially those of the northern Rift Valley, to allow volumetric or Monte Carlo simulation methods to be used meaningfully. The tendency to use identical (or closely similar) values for important parameters for which no exploration data exist, makes volumetric and Monte Carlo values too unreliable in this setting. Once the data collected in the northern Rift Valley by the BGS become widely available and are evaluated independently, it may be possible to perform a Monte Carlo simulation with greater accuracy.

An alternative approach would be to treat each prospect separately, utilizing various methodologies to match exactly the level of data available. This would fail the first test of providing a common basis of analysis, without significantly improving the assessment for most prospects.

3. Detail of Application

The available data for each significant prospect have been reviewed, and are described and tabulated in section 5.0. An assessment has been made of data quality, extent of coverage, and internal compatibility of results. Because much of this comes from unpublished or proprietary sources, the data cannot always be discussed in detail.

The likelihood of finding a geothermal field by drilling has been assessed for each prospect. The prospects are then grouped by risk (likelihood). Each prospect then is evaluated for probable size of field, using data developed at Olkaria as a reference value.

Following this estimate of reserves, the costs of exploration, drilling, wellfield development, transmission-line construction, and power plant construction were applied, to obtain a final ranking. For many prospects, costs have been expressed in terms of dollars per MW ($/MW) of developed resource at wellhead.

The prospects were then evaluated in terms of reserves (MW) and cost ($/MW), to provide the final ranking. These are then discussed, and recommendations are made for selection of one or more prospects.

E. INITIAL PRIORITIZATION OF GEOTHERMAL PROSPECTS BY POTENTIAL SIZE, LEVEL OF EXPLORATION RISK AND LOCATION

1. Methodology

The 28 geothermal prospects and one producing field (Olkaria) described in this section have been identified by the presence of some form of surface thermal activity, such as fumaroles, steaming ground and boiling or warm springs, or by hot groundwater or steaming conditions found in shallow wells. The prospects, identified by these thermal features, can be divided into 3 groups:

Group 1:

These are characterized by surface thermal features that are at the boiling point, and that are closely related geographically to areas of Holocene volcanic activity. Prospects with thermal features extending over areas of 24 to 40 km^2 are classified as Group 1A, whereas those with areas of 2 to 12 km^2 are classified as Group 1B. Probable reservoir temperature for Group 1A and 1B prospects is in the range of 240° to 300°C.

Group 2:

These are also characterized by surface thermal features at the boiling point, but the thermal features are not located close to areas of Holocene volcanic activity. Probable reservoir temperatures are likely to be in the range of 150°to 215°C.

Group 3:

These are characterized by surface thermal features at temperatures significantly less than boiling, and which are not located close to areas of Holocene volcanic activity. Group 3A prospects have probable reservoir temperature of 100° to 200°C, whereas Group 3B prospects have probable reservoir temperatures of 40° to 150°C, as determined from geochemical thermometry.

For several reasons, the chances of finding exploitable geothermal resources by drilling these prospects are greatest for the first group, decrease for the second, and are least for the third. There is a high probability that temperatures of Group 1 prospects will increase with depth along the boiling-point-for-depth curve, because temperatures already are at a maximum for surface conditions, and the presence of a nearby volcanic heat source implies proximity to a thermal fluid upflow zone.

The absence of obvious volcanic heat sources close to the Group 2 prospects could mean that the surface thermal activity, although at the boiling point, may represent an outflow zone which, although high-temperature is cooler than its associated upflow zone. In addition, temperatures beneath outflow zones typically decrease with depth for some distance below the outflow.

Group 3 prospects, characterized by springs which are at less than boiling temperature and which are not associated with recent volcanism, often are related to deep, regional groundwater flow and tend to have lower reservoir temperatures than either upflow or outflow zones associated with a volcanic heat source.

Table IV-1 lists the geothermal prospects of Kenya grouped into the categories described above. The locations of these prospects with respect to access roads are shown on Figure IV-8, and with respect to power transmission and distribution lines on Figure IV-9. Although Olkaria is a field undergoing development, rather than a prospect, it was found useful to include Olkaria in Table IV-1 and Figures IV-1 and IV-2 for purposes of completeness and comparison.

Table IV-1 also gives estimates of possible field areas, reservoir temperatures and power generation capacities of the various prospect groups and sub-groups. The basis for these generalizations is discussed in the following section.

Table IV-1: Classification of Ge
in Kenya by Level of

Listed in Groups fro

Group 1A - Possible field areas
Possible reservoir t
Possible field capac
area only) or 310 (e
as 500 MW
Listed from N to S:

Silali
Paka
Korosi

Group 1B - Possible field areas
Possible reservoir t
Possible field capac
Listed from N to S:

Central Island
Barrier Volcano
Namarunu

Group 2 - Possible reservoir t
Possible field capac
Listed from N to S:

Chepchok
Loruk
Ol Kokwe

Group 3A - Possible reservoir t
Possible field capac
Listed from N to S:

Kapedo/Lorusio
Homa Mountain
Lake Magadi
Mwananyamala

Group 3B - Possible reservoir t
Possible field capac
Listed form N to S:

Loyangulani
Kurru
Kureswa
Kijabe

Table IV-2. Characteristics of Geothermal Prospects

	Area of thermal anomaly, km^2	Probable reservoir temperature, °C	Probable depth to groundwater, m	Distance to transmission line, km	Distance to distribution line, km	Distance to access road, km
Group 1A						
Silali	24	240	250	100	55	12
Paka	36	240	150 - 550	100	55	18
Korosi	36	240	50 - 350	90	60	7
Eburru	32	285	100 - 800	13	(c)	0
Suswa	40	300	600 - 700	35	6	0
Group 1B						
Central Island	--	240	50	200	290	on island
Barrier Volcano	--	240	350 - 700	150	140	30
Namarunu	--	240	430	120	105	50
Emuruangogolak	7	240	600 - 700	115	60	35
Menengai	2	240	200 - 300	6	(c)	5
Longonot	12	240	750	10	(c)	1
Group 2						
Chepchok	1	150 - 215	140	100	45	6
Loruk	<1	150 - 215	40	85	70	0

Table IV-2. Characteristics of Geothermal Prospects (continued)

	Area of thermal anomaly, km^2	Probable reservoir temperature, °C	Probable depth to groundwater, m	Distance to transmission line, km	Distance to distribution line, km	Distance to access road, km
Ol Kokwe	<1	175 - 197	20	85	65	on island
Bogoria	10	190 - 200	10-50	55	35	0
Arus	<1	200 - 215	<380	45	32	2
Olobonita	300	170 - 190	hundreds	15	15	0
Group 3A						
Kapedo/Lorusio	10	155 - 172	(b)	90	65	0
Homa Mountain	13	179 - 200	(b)	60	20	0
Lake Magadi	300	100 - 140	(b)	80	60	1
Mwananyamala	18	152 - 180	(b)	60	35	0
Group 3B						
Loyangulani	(a)	71	(b)	200	185	0
Kurru	(a)	40 - 60	(b)	170	90	7 (track)
Kureswa	(a)	122 - 131	(b)	35	20	8
Kijabe	(a)	79 - 146	(b)	2	(c)	2
Maji Moto	(a)	101 - 104	(b)	105	32	0 (track)
Narosura	(a)	58 - 71	(b)	95	50	0
Masamukye	(a)	50	(b)	2	(c)	2

(a) Prospects identified by only one spring or spring cluster.

(b) Prospects in which thermal fluid reaches the surface as springs and therefore, depth to groundwater will be small and will depend on drilling location.

(c) Not reported for prospects within 15 km of transmission lines.

2. Summary of Prospect Characteristics

a. Possible Areal Extent

The possible maximum field size of 40 km^2 shown in Table IV-1 for prospect Group 1A is the maximum area of fumaroles and steaming ground for any prospect in that group. The minimum area of fumaroles and steaming ground is 12 km^2. The same maximum and minimum, figures for Group 1B prospects are 2 and 12 km^2.

This wide range of field areas estimated for Group 1A and 1B prospects reflects the uncertainty of these estimates. For example, at Paka, Korosi, Olkaria and Suswa, fumaroles and steaming ground cover 35 to 40 km^2 at each prospect. Some of this ground, however, may be underlain by relatively cool, and perhaps undevelopable, outflow zones. At Eburru prospect, the central area of Holocene eruptive centers and craters is about 5 km^2. The remaining area at Eburru might largely be outflow from the principal upflow zone. However, outflow zones often are developable commercially, either by use of flash-steam or binary-cycle technology. Therefore, presumed outflow zones cannot automatically be excluded from this assessment of resource size.

Alternatively, some of the smaller thermal areas may be underlain by much larger reservoirs. The surface thermal area at the 2,000 MW Geysers field in northern California, for example, covers less than 2% of the area of the developed reservoir. Consequently, in some cases the surface-area values given in Table IV-1 may be a better measure of the rate or intensity of heat release from the upflow zones than an approximate estimate of the areas of the underlying reservoirs.

Probable field areas have not been estimated for the prospects listed in Groups 2 and 3 that are characterized by hot springs, because hot springs are points of discharge from a reservoir and, as such, give no indication of the size or precise location of the reservoir. Three areas of steaming ground are included in Group 2: Chepchok, Loruk and Arus. These are relatively small prospects, each covering 1 km^2 or less. As stated above, however, they may overly much larger reservoirs. The Olobanita prospect is identified from wells which found hot water or which were dry but steaming, but because the wells are so few and so widely spaced, the extent of the prospect is highly uncertain.

b. Probable Reservoir Temperatures

Estimates of reservoir temperatures can be made prior to drilling by interpretation of the chemistry of hot spring waters and fumarole gases. Because of the generally great depth to groundwater in the Rift Valley, most of the thermal areas associated with the larger prospects consist of steaming ground and fumaroles rather than hot springs. The steam supplying the fumaroles has boiled off groundwater at depths ranging from a few tens of m to hundreds of m. The steam carries non-condensible gases which, in some cases, can be used to estimate reservoir temperatures. The chemistry of hot springs can be used to estimate reservoir temperature for those prospects that are low enough in elevation for the groundwater table to reach the land surface.

Because of their height above the groundwater table, no hot springs, but only steaming ground and fumaroles occur at the Group 1 prospects and at 3 of the Group 2 prospects (Chepchok, Loruk and Arus). All the thermal activity associated with the Group 3 prospects, however, plus two Group 2 prospects, Ol Kokwe and Bogoria, consists of hot springs and local patches of steaming ground.

The ranges of probable reservoir temperatures given for each group in Table IV-1 are based on:

(a) the geochemical temperatures derived for a number of chemical parameters, which were then applied to all the prospects in their respective groups; and

(b) the assumption that Group 1 reservoirs will have temperatures comparable to those found at Olkaria, which has the characteristics of a Group 1 prospect.

c. **Possible Power Capacities**

The range of power capacities estimated for the Group 1 prospects is given in Table IV-1. It is based on the results of numerical simulation of the Olkaria reservoir, which has given a maximum unit-area power capacity of about 13 MW per km^2. The field area estimates for Group 1A prospects range from 24 to 40 km^2, and from 2 to 12 km^2 for Group 1B prospects. From these values, the power capacity for Group 1A prospects using the above methodology is calculated to range up to 500 MW; the minimum calculated value may be as low as 65 MW, if only the central volcanic structure is considered, or as high 310 MW, based on the areas of fumaroles and steaming ground. For Group 1B prospects, the minimum and maximum power capacities are calculated by this method as being between 25 and 150 MW.

The power capacity estimates for Group 2 and 3 prospects (Table IV-1) are based in part on the extent of the area of thermal activity, and in part by analogy with developed fields located in similar geologic settings and which have similar reservoir temperatures.

3. Prospect Descriptions by Risk Group

Following is a brief description of the individual prospects. The groups are discussed in sequence from the lowest risk group 1A to the highest risk Group 3B. Within each group, however, prospects are listed from N to S, a sequence which clearly has no bearing on the relative risk of finding an exploitable reservoir within the group.

a. Group 1A

These prospects are characterized by extensive surface thermal activity at the boiling point, and by a close association of this activity with recent volcanic centers. Boundary lines drawn around the scattered fumaroles and the broader patches of steaming ground enclose areas ranging from about 24 to 40 km^2. The expected range of reservoir temperatures in this group is from 240° to 300°C, and the estimated power capacities range up to 500 MW. From N to S, these prospects are Silali, Paka, Korosi, Eburru, Olkaria and Suswa.

Silali This prospect extends over an area of about 24 km^2 whose center is about 55 km N of the N shore of Lake Baringo, and about 12 km E of the nearest road access at the town of Kapedo. The thermal activity, as mapped by the BGS, consists entirely of fumaroles and steaming ground at temperatures between 38° and 97°C. This activity mainly is concentrated within an enclosed, elliptically shaped caldera measuring 5 x 7 km. The floor of the caldera is at an elevation of 1,000 m, whereas the lowest point on the caldera rim is at 1,200 m. The water table, as indicated by the elevation of the hot springs at Kapedo, is at an elevation of 740 m or slightly higher. Therefore, water rest-levels in wells drilled within the crater should be at a depth of about 250 m. If temperatures increase with depth along a curve of the boiling point with hydrostatic depth, temperatures on the order of 250°C could be expected between depths of about 600 to 700 m. However, for purposes of conservatism, a minimum depth of 1,000 m below the water table is assumed as the likely drilling depth for all prospects, based on the Olkaria experience. Non-condensible gas samples have been collected by the BGS for the purpose of estimating the reservoir temperature; preliminary results were made available for this report. Data are expected to be released in final form at the end of 1990 or early in 1991.

Paka This prospect is located about 30 km NNE of the N shore of Lake Baringo, and is about 18 km E of the nearest access road. The area of steaming ground and fumaroles, as mapped by the BGS, is about 4 x 9 km. The anomaly straddles the crater of Paka volcano, and its long dimension coincides with NNE-striking faults which offset the young lava flows. The elevation of the area of steaming ground ranges from about 1,000 to 1,400 m, and because the elevation of the groundwater table probably is about 850 m, the depth to ground water should range from 150 to 550 m. The BGS has taken samples of non-condensible gas from these fumaroles, which were available for this report. Final data are scheduled to be released at the end of 1990 or early in 1991.

Korosi This prospect is located about 6 km N of the N shore of Lake Baringo and, like Paka, it is a 4 x 9 km area of scattered fumaroles straddling the crater area of a young central volcano. The prospect is 7 km from the nearest road. The long axis of the anomaly parallels the NNE trend of the many faults crossing the volcano. The topographic elevation of the prospect ranges from about 1,000 to 1,300 m, whereas the elevation of the groundwater table beneath the area is estimated to be 950 m. Depth to groundwater, therefore, is estimated to range from 50 to 350 m. Although there are no hot springs to be sampled to determine reservoir temperatures, gases from the fumarole have been sampled for this purpose by the BGS.

Olkaria The steaming ground associated with Olkaria defines an irregularly shaped area covering about 35 km^2 just to the SW of Lake Naivasha. The thermal areas are associated with a number of recent domes and craters, as well as with N- and NW-trending fracture zones. It has been suggested these features are genetically related to a young caldera 8 x 10 km in diameter. Forty-five MW of electric power are being produced from some 25 wells covering an area of less than 4 km^2. The average productivity of Olkaria wells is 2.5 to 3.0 MW. Exploration drilling has proven an additional 10 km^2 of producible field to the N and NW of the existing well field. The southern part of the Olkaria area, as defined by surface thermal features, appears to be an outflow zone, in which temperatures are cooler at depth than in the productive field, and which may prove to be largely unproductive.

Eburru The steaming ground and fumaroles defining the Eburru prospect extend over an area 8 km N-S by 4 km E-W. The prospect is located 12 km NW of Lake Naivasha and is easily accessible by road. On the S (at 2,500 to 2,700 m elevation), the thermal areas are associated with several young craters on the top of Eburru volcano. Further north the thermal areas occur along N-trending faults and young extrusion centers down to an elevation of 2,000 m. Four deep exploration wells were drilled at Eburru during 1989: one in the crater area, one S of the crater area, and 2 E of the steaming, N-trending faults. The hole drilled in the crater area was successful, producing thermal fluid with a generating potential of about 2.5 MW. The other 3 holes were unsuccessful. Two additional wells were drilled in mid-1990 to the N and NW of the initial successful Eburru well. These were designed to test a chemical and geophysical anomaly of about 5 km^2 in area. Preliminary temperature data suggest that one hole may be unsuccessful, whereas the second hole remains untested at this time. The large area of steaming ground located at lower elevation on the N flank of Eburru volcano (sometimes called Cedar Hill, Eburru Station and the Badlands) has yet to be tested. It remains unknown if this lower-elevation zone is outflow from the main crater area, or represents a separate upwelling of thermal fluid.

Suswa The high-temperature fumaroles associated with Suswa volcano define an area of 8 x 5 km. Suswa volcano, which is located about 50 km NW of Nairobi, is unique in having a central ring structure which forms a deep, topographic trench which, in turn, surrounds a central "island" structure. The diameter of the island within the trench is about 5 km. Many of the fumaroles associated with Suswa volcano occur within the trench, but others occur within a larger outer caldera. The outer caldera is easily accessible by existing dirt tracks, but the island is difficult to reach, even by foot. The elevation of the outer caldera floor averages about 1900 m. As the local elevation of the groundwater table is estimated to be about 1250 m, the estimated depth to groundwater is 600 to 700 m. Because of the depth to groundwater, no hot springs occur at Suswa. Armannsson (1987), however, has calculated reservoir temperatures from CO_2 gas discharging with the fumarole steam: fumaroles in the trench give temperatures in excess of 300°C; the caldera-floor fumaroles indicate temperatures a little below 300°C; and the caldera rim fumaroles give temperature of 270° to 290°C.

b. Group 1B

The expected range of reservoir temperatures in this group is the same as for Group 1A prospects, but the surface thermal anomalies associated with Group 1B are significantly smaller than in Group 1A (2 to 12 km^2 as compared to 24 to 40 km^2). Consequently, the probable potential of a Group 1B prospect is in the range of 25 to 150 MW.

The Central Island, Barrier Volcano and Namarunu prospects are all located in the far N of the Rift Valley; because of their remote location they have yet to be surveyed in detail. All that is known is that they contain fumaroles and steaming ground associated with young volcanic centers. They have been placed in Group 1B because it is believed that the areas of steaming ground extend over areas of only a few km^2, but this assumption may be revised when better information becomes available.

A brief description of the Group 1B prospects, listed from N to S, follows.

Central Island This prospect is located on Central Island in Lake Turkana. This is a volcanic island located 12 km from the western (nearest) shore of the lake. Although hot springs and steaming ground at boiling temperature have been reported, little else is known of the occurrence. No chemical analysis or geochemical temperatures have been reported.

Barrier Volcano This prospect is located at the S end of Lake Turkana where a young volcanic complex forms a topographic barrier between the lake on the N and the lower-elevation Suguta valley on the S. From Silali volcano northward to the Barrier, a distance of 130 km, the Suguta Valley occupies the axis of the Kenya Rift. The Barrier is composed of 2 principal volcanoes, Teleki's volcano on the N and Andrew's volcano on the S. Fumaroles are associated with both volcanoes. Teleki's volcano was active in historic time; Andrew's also may be active. The elevations of Teleki's and Andrew's volcanoes are about 650 m and 1,000 m respectively. By comparison, the probable groundwater elevation beneath the Barrier is at about 300 m. Depth to groundwater, therefore, is expected to range from 350 m to 700 m. No inferred reservoir temperatures from chemical geothermometry have been reported. The nearest maintained road is 30 km from the prospect.

Namarunu This prospect is characterized by fumarole activity associated with Namarunu volcano, which is located in the Suguta Valley about 40 km S of the Barrier volcanoes and 50 km N of Emuruangogolak volcano. Because of its extreme remoteness, the prospect has not been mapped in detail, and no accurate information is available concerning the extent of the fumarole field or the chemistry of the fumarole gases. The elevation of the volcano averages about 700 m compared to the elevation of the Suguta valley, directly to the E, at 270 m. Depth to groundwater, therefore, would be about 430 m.

Emuruangogolak This prospect is located 95 km N of the N shore of Lake Baringo and is the most remote of those surveyed thus far by the BGS. Although a track passes within 8 km of the thermal area, the closest maintained road is 35 km to the E. Thermal activity, in the form of fumaroles and steaming ground, occurs over a circular 7 km^2 area located near the summit of a young volcano. Steam temperatures range from 47° to 94°C. As in the case with the thermal areas associated with the 3 volcanoes to the S, the BGS has recently collected gas samples at Emuruangogolak for the purpose of estimating reservoir temperature. This information may be released late in 1990. The estimated range of depth to groundwater beneath the thermal area is 600 to 700 m.

Menengai Two fumarole fields have been described in Menengai caldera (McCall, 1967) ranging in temperature from 64° to 90°C. The extent of these fields has not been mapped, but evidently they are quite small compared to the size of the caldera itself, which is 8 x 12 km. The volcano appears to have been active within the past few thousand years. The caldera is located just N of Nakuru, and the rim is easily accessible from the surrounding farm land. However, the caldera floor consists of a great expanse of slaggy lava flows which make the interior of the caldera difficult to traverse, even by foot. Terrain elevations within the caldera range from 1,800 to 2,100 m. Although no wells have been drilled to determine depth to groundwater, it is estimated that the groundwater table in the caldera is at an elevation between 1,700 and 1,800 m. Depths to groundwater, therefore, would range from 100 to 300 m.

Longonot Longonot is a prominent central volcano located just SE of Lake Naivasha, and only 15 km E of the Olkaria geothermal field. Fumaroles, ranging in temperature from 47° to 90°, occur along the inner rim of the summit crater of the volcano. The crater is 2 km in diameter, and is accessible only by foot because of the steep outer slope of the volcanic cone and the even-greater steepness of the inner crater rim. The steep cone of the volcano occupies the east side of a caldera which is 6 km in diameter. Four small areas of steaming ground, ranging in temperature from 43° to 74°C, occur on the S side of the caldera. It is unknown if these are related to outflow from a high-temperature zone to the N, or represent a separate zone of upwelling. The elevations of the top of the groundwater table and the top of geothermal fluid production may be at about the same elevation as at Olkaria; that is, 1,600 m and 1,200 m, respectively. Because of the difficult terrain, directional drilling from outside the crater would be required to access the area beneath the crater. Assuming a maximum horizontal throw to depth ratio of 1:2, it would be difficult to find many drilling sites on the steep slope of the volcano that would be close enough to the crater to allow the drilling of targets located vertically beneath it. One such site, however, may exist on the NW side of the volcano at an elevation of about 2370 m. Depth to groundwater from this site would be about 750 m.

c. Group 2

The Group 2 prospects, like those in Group 1, are characterized by surface thermal feature at the boiling point. However, unlike the Group 1 prospects, those of Group 2 are not closely associated with recent volcanic activity. Reservoir temperatures are estimated to range from 150° to 215° C, and power generating capacity from 10 to 50 MW. From N to S, these prospects are: Chepchok, Loruk, Ol Kokwe, Bogoria, Arus and Olobanita.

Chepchok This prospect consists of approximately 1 km^2 of fumaroles and steaming ground, located 20 km NNE of the N shore of Lake Baringo and 8 km S of the summit of Paka volcano. There are no recent volcanic centers at Chepchok, but N- to NNE-trending fault scarps are prominent. The thermal activity occurs along the bed of the Komol river, at an elevation of about 1,040 m. The Komol River separates Korosi volcano on the S from Paka volcano on the N. The course of the river, therefore, is the lowest land surface between the two volcanoes. Because of Chepchok's location on faults striking toward Paka volcano, and because of its relatively low elevation, it is possible that the thermal features at Chepchok are related to southward outflow of thermal fluid originating from the Paka upflow zone. The elevation of the groundwater table below Chepchok is estimated to be about 900 m, giving a depth to groundwater of about 140 m. The prospect is about 6 km NW of a maintained road.

Loruk This is a small area of steam and hot air vents located along the road paralleling the W shore of Lake Baringo, about 5 km S of Loruk settlement. The vents issue from fractures in lava at an elevation of about 1,000 m, which is about 40 m above the level of Lake Baringo. The W shore of the lake is about one km E of the thermal area. Temperatures up to 92°C have been measured in the vents. There is no obvious volcanic or structural feature controlling the location of discharge other than the N-trending fractures of the Rift Valley floor.

Ol Kokwe Hot Springs and steaming ground, with a maximum temperature of 94°C, occur on Ol Kokwe island in Lake Baringo. Although two basalt scoria cones occur on the W side of the island, the thermal manifestations occur in older lavas on the E side. Because the age of the basalt cones is uncertain, and because Ol Kokwe island is not a major volcanic center comparable to those associated with the Group 1 prospects, the Ol Kokwe prospect has been classified in Group 2. The silica and alkali geothermometers give reservoir temperatures between 175° to 197°C (Allen et al., 1989). Depth to groundwater is about 20 m.

Bogoria The most impressive discharge of hot springs in Kenya occurs along the S, SW and SE shores of Lake Bogoria. Most of the springs are boiling, some very vigorously, and some are associated with steaming ground. There are no young volcanic centers in the vicinity, and although the lake occupies a major half-graben structure, the location of many individual thermal features does not appear to be fault-controlled, because most of the springs are not on the faulted side of the half-graben. A possible explanation for the location of the springs is that Lake Bogoria, at an elevation of about only 990 m, is the first surface-discharge point for groundwater flowing northward in the Rift Valley from the vicinity of Menengai, located 40 km to the S. Water infiltrating in the Menengai area could easily reach depths of several km before discharging at Bogoria. Over this distance between points of recharge and discharge, the water could be heated either by shallow magmatic heat sources in the vicinity of Menegai, or by the high regional heat flow to be expected in this volcanically active part of the Rift Valley. Because of problems in interpreting mixing ratios and times of mixing between thermal fluid, lake water and local groundwater, geothermometry results are ambiguous. Although the uninterpreted silica and alkali geothermometers give temperatures below 150°C, gas thermometers and various mixing models give reservoir temperatures of 190° to 200°C. The latter are the more likely values, considering the vigorous boiling activity of the springs. As the springs are at lake level, the depth to groundwater would be only a few m to a few tens of m, depending on the drilling site. A well-maintained road provides access to the W shore of the lake. The road is maintained because the lake, which supports a large flamingo population, has been declared a National Reserve. Because of this designation, development of the prospect will be environmentally sensitive.

<u>Arus</u> This prospect, located 16 km W of Lake Bogoria and 50 km N of Nakuru, consists of several strong fumaroles and boiling mud pools extending for a distance of several hundred m along the E bank of the Molo River. Although not entirely clear, it can be inferred from topographic relief that this section of the Molo river is following a fault scarp bordering the W side of a narrow, E-dipping fault block. This fault, one of many on the Rift Valley floor in the vicinity, is close to the central axis of the Rift. Although there are no young volcanic centers close to the prospect, a center from which Quaternary flood basalts were extruded is located at Goituimet, 9 km S of the prospect. Geochemical temperatures of 200° to 215°C have been reported for the reservoir. The fumaroles are at an elevation of 1,370 m, which is 380 m above the level of Lake Bogoria. It is likely, therefore, that depth to groundwater should not exceed about 380 m. Except for the narrow canyon of the Arus river, the prospect is surrounded by flat terrain. The closest vehicle access is a dirt road located 2.5 km to the SE.

<u>Olobanita</u> The area of this prospect is poorly defined, because its location is not based on the presence of surface thermal activity, but instead on the distribution of a number of hot wells drilled in the rolling country N of Menengai crater. The location of these wells has been described by several authors (McCall, 1967; Baticci, 1987; Geothermica Italiana, 1989). Not all of these descriptions agree in detail, because some of the older well locations cannot be verified, and some wells can no longer be entered. Nevertheless, there is general agreement that about 10 wells, drilled from 1 to 30 km N and NNW of Menengai, have encountered anomalously high temperatures ranging from 30° to 98°C. Few of the wells encountered water, and the hottest wells found steam under very low pressure. The area within which

the hot wells occur is about 10 km E-W by 30 km N-S. The northernmost steaming well is at Mugurin, which is only 9 km SE of the Arus prospect. There are no young volcanic features in the area; however, older, partially buried calderas have been mapped N of Menengai. The area is easily accessible by many farm roads. The depth to groundwater is not known, but may range up to several hundred m. Chemical geothermometry indicates reservoir temperatures in the range of 170° to 190°C from the gases sampled in a well located 6 km NW of Menengai crater.

d. Group 3A

Like Group 2 prospects, those of Group 3 are not closely related to recent volcanic activity; but unlike Group 2 prospects, surface thermal features are at temperatures less than boiling. Based on chemical geothermometers, the probable reservoir temperatures of Group 3A prospects are in the range of 100° to 200°C. Based on analogy with developed fields in similar geologic settings, the probable power generating potential of Group 3A prospects is estimated to be in the range of 5 to 50 MW.

There are 4 prospects that fall in to the 3A category. Listed from N to S, these are Kapedo/Lorusio, Homa Mountain, Lake Magadi and Mwananyamala. Brief descriptions of these prospects follow.

Kapedo/Lorusio Two hot spring areas, 9 km apart, are described herein as one prospect. Kapedo hot spring is located 12 km W of Silali volcano, and Lorusio hot spring is located 9 km N of Kapedo hot spring. Kapedo is directly accessible from a maintained road, and Lorusio by a motorable track from Kapedo. The maximum temperatures of these springs are 52°C at Kapedo and 81°C at Lorusio. The composition of Kapedo water is equivalent to the water of Lorusio diluted by an equal amount of very dilute, cold groundwater. Therefore, interpretation of the geothermometer data is ambiguous. Although alkali geothermometers yield reservoir temperatures of 172°C for Lorusio and 155°C for Kapedo, silica temperatures are similar to measured surface temperatures, possibly because of mixing of the thermal water with cool, dilute surface water. The high Na/K ratio of both springs supports the lower (silica) temperature interpretation. Whether these hot springs derive their heat from shallow magma beneath Silali volcano, or from deep circulation in a area of high regional heat flow, is uncertain. Satellite craters, located on the W flank of Silali, are as close 6 km from the Kapedo springs. Therefore, it is possible that the thermal water is outflow from a convecting upflow zone beneath these craters or beneath Silali itself.

Homa Mountain This prospect is located in the Kavirondo Rift of western Kenya on the shore of Lake Victoria, about 40 km SW of Kisumu. Homa Mountain is a late Tertiary or early Quaternary carbonatite volcanic complex about 10 km in diameter. Three hot springs occur at the base of the mountain: Abundu and Ongoro springs on the N, and Nyabondo springs on the S. The highest measured temperature is 90°C at the Abundu springs. Total flow from the springs is about 13 l/s. Tole (1990) reported that quartz geothermometry gives reservoir temperatures in the range of 142° to 179°C, whereas a conservative interpretation of the alkali geothermometers indicates a temperature of 200°C. These reservoir temperatures appear somewhat high in view of the possible Tertiary age of volcanism at Homa Mountain. The chalcedony geochemistry, which is applicable to low and moderate temperature water, indicates only 110°C. It is possible that the unusual chemistry of the hot spring water (highly saline and alkaline sodium bicarbonate-chloride), itself probably a function of water:rock reactions within the old volcanic center, is causing the alkali geothermometer to give spurious temperature results.

Lake Magadi Numerous hot springs occur around the shores of Lake Magadi, a highly saline lake located in the Rift Valley about 80 km SW of Nairobi. The hottest springs occur at the N end of Little Magadi Lake, a satellite feature immediately to the NW of Lake Magadi. The maximum spring temperature is 86°C, and the rate of discharge from these high-temperature springs is approximately 50 l/s. The surface geology consists of Pliocene(?) basalt flows, that have been broken into horsts, grabens and half-grabens by Pliocene-Pleistocene faulting. The grabens contain a thin layer of lacustrine and evaporite beds. There are no recent volcanic extrusions in the vicinity of the lake, and the springs emerge from a number of north-trending faults. Because there is a long history of mining trona from the lake, over the years there have been many studies concerning the origin of the hot springs and their relationship to the complex carbonate chemistry of the lake. Because of the probability of complex mixing and recirculation of lake water, groundwater and spring water, a clear picture of the origin of the springs has yet to be developed. There is general agreement, however, among the various interpretations of geothermometer results, that the temperature of the hot spring reservoir is in the range of 100°C to 140°C, preferentially at the higher value. Because of the trona plant, a paved road is maintained from Nairobi to the central shore of the lake. From there, a motorable track reaches within 2 km of the NW shore of the lake where the hottest springs are located.

Mwananyamala This prospect is located in SE Kenya about 60 km SW of Mombasa and consists of 4 hot springs distributed over an area of 9 x 2 km. The springs discharge from fractures and joints in Permian/Triassic sandstone. Dikes of Cretaceous age intruded into the sandstone appear to control the discharge area of two of the springs (Tole, 1990). Surface temperatures range from 55° to 76°C with a total surface flow rate of less than 1 l/s. Quartz and most of the alkali geothermometers give reservoir temperatures in the range of 125° to 180°C. However, the Mg-corrected alkali thermometer yields a much-lower value. Because spring flow is so low, the effects of contamination by mixing with shallow groundwater is greater than otherwise, thereby complicating any interpretation.

e. Group 3B

This group of prospects is characterized by: (a) spring temperatures less than boiling; (b) non-association with young volcanic or intrusive centers; and (c) probable reservoir temperatures in the range of 40° to 120°C, as indicated by geochemical thermometry. Probable power-generating capacities of prospects in this group are only 5 to 10 MW.

<u>Loyangalani</u> This prospect is located on the SE shore of Lake Turkana at the town of the same name. According to Tole (1990), the highest temperature of the springs is 39.8°C and the reservoir temperature, inferred from the quartz geothermometer is 71°C. Our reappraisal of Tole's analysis suggests 40° to 60°C.

<u>Kurru</u> This prospect is located in central Kenya, about 80 km ENE of Archer's Post. Maximum measured temperature (Tole, 1990) was 42°C. Inferred reservoir temperatures are 75° to 105°C based on the several silica geothermometers, and 170°C on the basis of the alkali geothermometer. Given the very high ratio of Ca:Na+K for the spring waters, the alkali geothermometer may be giving too high temperatures. The springs flow from crystalline basement rock, and are located about 20 km NE of the nearest outcrops of young basalt flows.

<u>Kureswa</u> This prospect is located at the southern end of the Kerio Valley, about 60 km SE of Eldoret. The Kerio Valley is a subsidiary part of the Rift Valley system. The hottest spring (Tole, 1990) is 63°C. The silica geothermometers give reservoir temperatures of 90° to 122°C, and the alkali geothermometer gives about 120°-130°C. The altitude of the spring is about 2,000 m.

<u>Kijabe</u> This prospect is located 45 km NW of Nairobi on the eastern escarpment of the Rift Valley. It consists of 43°C springs, with geochemically inferred reservoir temperatures in the range of 40° to 146°C. The springs discharge from a Rift Valley fault, from which it is inferred that the temperature anomaly is due to deep circulation of groundwater in an area of elevated temperature gradient.

<u>Maji Moto</u> This prospect is located in southern Kenya, W of the Rift Valley. The hot springs occur at the contact between

Tertiary volcanic ash and underlying Precambrian metamorphic basement (Tole, 1990). Maximum discharge temperature is 57°C, and the total flow rate for the spring group is estimated to be less than 1 l/s. The quartz and most of the alkali geothermometers give reservoir temperatures of 101° to 104°C; however, chalcedony and Mg-corrected alkali temperatures are about 60°C.

Narosura This prospect is located 28 km SE of Maji Moto. The maximum surface temperature of the warm spring is 31°C and its flow rate is estimated at about 2 l/s. The quartz geothermometer gives an inferred reservoir temperature of only 58° to 71°C.

Masamukye This prospect is located near the Nairobi-Mombasa road, about 140 km SE of Nairobi. The springs rise in the bed of the Muooni river from fractures in Precambrian metamorphic basement. The prospect is 4 m S of outcrops of the Pleistocene Ngun basalts (Tole, 1990). The highest spring temperature is 43°C, and the reservoir temperature indicated by the silica geothermometers is between 45° and 70°C.

4. Initial Prospect Prioritization

An important aspect of the distribution of prospects in Kenya is that 7 of the 11 low-risk, potentially large fields are located N of Lake Baringo, where the distance to the nearest transmission grid is in excess of 90 km. Distance to the transmission grid is an important criterion for establishing exploration priority; therefore, the criteria for selecting prospects distant from the grid will be somewhat different from the selection criteria for those fields closer to the grid. Mostly, the remote prospects must have a relatively large potential to justify the expense of constructing a long transmission line. To simplify the prioritization process, prospects first have been separated into categories defined by distance to the transmission grid.

The 29 prospects listed in Table IV-2 can be divided into 3 groups, those which are: (a) 2 to 60 km; (b) 80 to 120 km; and (c) 150 to 200 km from the transmission grid. If those prospects in the 150 to 200 km group (Central Island, Barrier Volcanoes, Loyangalani and Kurru) are eliminated from further consideration because of their extremely remote location; and if all of Group 3B prospects (which include two of the remote prospects), are eliminated because of their small potential (probably 10 MW or less), then the 19 remaining prospects can be grouped into two categories: 10 prospects located less than 60 km from the grid and 9 prospects located 80 to 120 km from the grid.

Table IV-3: Initial Priority Listing of Prospects Located Less Than 60 km from the Transmission Grid.

	Prospect	Risk Group
1.	Suswa	1A
2.	Eburru	1A
3.	Arus	2
4.	Longonot	1B
5.	Menengai	1B
6.	Lake Magadi	3A
7.	Olobonita	2
8.	Homa Mountain	3A
9.	Mwananyamala	3A
10.	Bogoria	2

a. Initial Prioritization of Prospects Located Within 60 km of the Transmission Grid

Ten prospects are listed in Table IV-3 from highest to lowest exploration priority. The reasons for assigning these priorities are as follows.

Highest priority is given to Suswa because of its probable high reservoir temperature, its probable large generation capacity and its easy accessibility. The main difficulty anticipated with development is the great depth to groundwater, estimated to be 600 to 700 m. These great depths, assumed to be 1,000 m below the groundwater table, increase drilling costs and decrease power output, compared to wells collared at elevations closer to the water table.

Second priority is given to Eburru, where high subsurface temperature and the existence of a permeable reservoir already have been proven by drilling. Even though only 1 of 4 deep exploration holes has been successful, very little of the area of steaming ground to the N has been tested.

Third priority is given to Arus, even though it is in a higher- risk category (Group 2) than either Menengai or Longonot, because: (a) there is a potential for tapping a hot water body significantly larger than the prospect area; (b) wells may be as shallow as 1,000 to 1,500 m; (c) the area is flat and easily accessible from both existing roads and the transmission grid; (d) land acquisition should not be costly because it is mostly low-productivity grazing land; (e) a drilling target could be chosen without extensive surface exploration; and (f) drilling water is readily available from the nearby Molo river. This probably would be the quickest and lowest-cost prospect of all to explore.

Only fourth priority is given to Longonot, despite its proximity to Olkaria. It is a category 1B risk because finding suitable drilling sites from which to target wells beneath the summit crater will be difficult. Depth to groundwater also is great.

Fifth priority is given to Menengai, also a 1B risk prospect. Difficult ground access within the crater, and a relatively small area of active fumaroles are its main drawbacks. Its pluses include evidence of recent magmatism, probable high temperature, and proximity to major population centers and to transmission lines.

Sixth priority is given to Lake Magadi, because of its probable low reservoir temperature. Although this prospect is 80 km from the transmission grid, it is included with the group of prospects located within 60 km of the transmission grid because of the possibility of an off-grid market for electric power and by-product fresh water at the trona plant.

Lower priorities are given to the Olobonita, Homa Mountain and Mwananyamala prospects, in spite of their large areas and favorable inferred reservoir temperatures, because drilling targets are not obvious, and major exploration programs, including gradient drilling to several hundred m, will be required at all 3 prospects before sites can be selected for deep exploration drilling. Even then, it might not be possible to prove the existence of a commercial geothermal reservoir with only one or two deep exploration wells.

Lowest priority is given to Bogoria, in spite of its large area and reasonably high inferred reservoir temperatures, because considerable opposition to development can be anticipated based on environment considerations and the existence of a national game preserve. If this opposition can be eliminated by means of agreements regarding land use and animal protection, the priority ranking given to Bogoria would change significantly.

Table IV-4: Initial Priority Listing of Prospects Located 80 to 120 km from the Transmission Grid

Prospect	Risk Group
1. Korosi	1A
2. Paka	1A
3. Silali	1A
4. Chepchok	2
5. Kapedo/Lorusio	3A
6. Loruk	2
7. Ol Kokwe	2
8. Emuruangogolak	1B
9. Namarunu	1B

b. Initial Prioritization of Prospects Located 80 to 120 km from the Transmission Grid

Nine prospects are ranked in Table IV-4 from highest to lowest exploration priority. The reasons for assigning these priorities are as follows.

First, second and third priority are given to Korosi, Paka and Silali, because all 3 are in the category of lowest exploration risk and highest probable generating capacity. Korosi is given first priority because it (a) may require the shallowest wells to develop, (b) is closest to the grid, and (c) requires the shortest length of new access road. Paka and Silali are about equal in terms of priority, even though access into Paka may be slightly easier than for Silali, and the thermal features reportedly are more intense.

In contrast to this ranking, the BGS, based on the content of fumarole gases, have ranked the geothermal potential of Korosi behind that of Paka and Silali. We have not adopted the BGS ranking because: (a) the most diagnostic gases for identifying reservoir temperature (H_2s, CH_4 and H_2) were found in such low concentration that reliable interpretations of reservoir temperature could not be made, and (b) use of the less-diagnostic gases, such as He_2, are considered too imprecise and theoretical for this application. Our priorities are based on probable drilling depths, distance from access roads, distance from the transmission grid, and overall likelihood of finding a commercial geothermal reservoir.

Fourth priority is given to Chepchok. Even though the thermal anomaly is small in size, drilling should be relatively shallow (1,000-1,500 m) because of the low elevation of the prospect, and access should be relatively inexpensive because of comparatively level ground and proximity to an existing road.

Fifth priority is given to the Kapedo/Lorusio prospect mainly because of ease of access. However, if the thermal features are related to shallow outflow from Silali, subsurface temperatures may be disappointing. Further, the large areal extent of the prospect makes the selection of exploratory drilling sites less simple and therefore somewhat riskier.

Sixth priority is given to Loruk. This area will require considerable exploration effort, because there is no obvious drilling target or identified controlling structure other than N-S-trending faults. However, access is easy, and exploration should be straightforward, emphasizing temperature-gradient drilling to several hundred m.

Lowest priorities are given to Ol Kokwe, Emuruangogolak and Namarunu. In spite of the size and probable high reservoir temperature of Emuruangogolak and Namarunu, both prospects are very remote. Exploration, exploratory drilling and development would be expensive, slow and difficult. Ol Kokwe is located on an uninhabited island in the middle of Lake Baringo. This isolated position makes drilling and development expensive and therefore unlikely.

F. COST OF GEOTHERMAL EXPLORATION, DEVELOPMENT AND FIELD OPERATION

1. Description of Cost Factors

In this section, the costs associated with exploration, field development (including the production wellfield, steam gathering lines and transmission line, but excluding power plant and auxiliary structures), and field operation (including make-up well drilling, but excluding power plant maintenance) are discussed in general. They are discussed in further detail for specific prospects in Section G.

Costs can be considered as a function of the following factors, both in an absolute sense and relative to other prospects:

Prospect accessibility: necessity for road construction; necessity to construct field camp; additional travel to/from prospect; additional time and cost of conducting field surveys in difficult terrain; uncertainty arising from incomplete field work in inaccessible parts of prospect; seasonal constraints on access

Prior investigation: level of completeness and utility of prior investigations; time and cost savings realized from use of prior work versus additional project risk (if any); need to repeat surveys or augment prior work

Proximity to market and transmission lines: available line capacity (if any); construction of additional lines; possibility of local off-grid utilization of electricity; timing of incorporation into grid

Resource size: economies of scale; reward versus risk in large and small prospects; reserve capacity for contingencies

Resource characteristics: required depth of drilling; likely yield per well; geologic complexity as a factor in determining drilling success rates; chemical or physical constraints on resource utilization (scaling, corrosion, fluid enthalpy); anticipated rate of pressure drawdown.

Power plant: generation mode as a function of resource characteristics and size; fabrication and erection time as a function of generation mode and plant size.

Financing: financing sources, terms and conditions; availability of grants, soft loans and vendor credits; project insurance; terms of sale of electricity; repatriation of hard currency.

Environment: constraints on access, drilling, construction, water consumption, and waste disposal; requirements for payment of compensation for damages; possible interruption of project activities.

Power plants and project finance are discussed by The Ben Holt Company in its report. We have used their cost numbers in evaluating the various prospects. Most of the resource areas are suitable for flash-steam generation; however, for a few, binary-cycle generation is preferred. Distance from existing transmission lines has been noted for each prospect, and the cost of transmission lines is calculated in general terms for each prospect.

2. Exploration Stage Costs

Exploration costs are dominated by the cost of exploratory drilling. The cost of exploratory drilling largely is a function of the precision of target-selection (risk), and the depth to the geothermal resource. Therefore, for fields of comparable depth, any field at which a discovery has been made by drilling will be less costly to develop than one which has not been drilled or at which drilling has resulted in no discovery. However, undiscovered fields at shallow depth may be less costly to develop than discovered deeper fields.

Because the passage of time represents lost financial opportunities, lengthier exploration programs typically become more expensive than shorter programs, even if the same work is accomplished in each. Of course, there is a tendency to incorporate more work into a lengthy program, with greater expenditure. The possible advantage of having these additional data must be weighed against both the cost of collecting these data and the opportunity cost of lost time.

Remoteness of a prospect tends to add most to the cost of otherwise comparable programs. Roads and field camps may need to be constructed, and additional workers, supplies and equipment may be needed. Access may be impeded seasonally. Water supplies may need to be developed locally via wells or pipeline; alternatively, expensive truck haulage may be required.

Geothermal exploration typically is built on 4 cornerstones:

1. An understanding of geologic structure and heat source: obtained from geologic mapping, gravimetry, and drilling.

2. Temperature distribution in the subsurface: obtained initially from fluid chemistry, and ultimately from temperature-gradient and exploratory drilling.

3. Identification of a permeable and porous structure (the reservoir): inferred from geologic mapping, various geoelectrical methods, and fluid chemistry, and confirmed by results of drilling and well testing.

4. Recognition of fluid characteristics (phase, salinity, mixing patterns, flow directions): determined principally from fluid chemistry, drilling and well testing, and indirectly from geology and temperature data.

From this, an exploration program can be justified that begins with (or utilizes existing) geologic mapping, fluid geochemistry, and gravimetry. After this, typically there are geoelectrical surveys and drilling of temperature-gradient holes. This is followed by construction of a conceptual geologic model, and the selection of exploration well sites, based on the model. Other suites of information (seismic, petrochemical, infra-red, or aeromagnetic, for example) may be interesting, but usually are not essential to the program, and therefore cannot be justified on a cost or time basis except in exceptional cases.

Exploration costs, as noted above, will vary with the level of prior work, the prospect location and accessibility, the geologic complexity as observed in work to date, and the size of the prospect. It is not possible to prepare detailed estimates of exploration cost for each prospect. However, based on the exploration principles described earlier, it is possible to generalize the costs of the main elements of an exploration program: geologic mapping, fluid geochemistry, gravimetry, electrical resistivity or magnetotellurics, and drilling of temperature-gradient holes, followed by conceptual modeling and drill-site selection (Table IV-5).

Table IV-5: Exploration Costs at an Average Prospect

Geologic mapping: Assume 4 man-months at US$15,000 per month, plus US$30,000 for support, printing and miscellaneous. Total: US$90,000 per prospect, where needed.

Geochemistry: Assume 3 man-months at US$15,000 per month, plus US$50,000 for support, chemical analyses, printing and miscellaneous. Total: US$95,000 per prospect, where needed.

Gravimetry: Assume 2 crew-months at US$30,000 per month, plus US$30,000 for support, data processing, printing and miscellaneous. Total: US$90,000 per prospect, where needed.

Geoelectrical surveys: Assume 3 crew-months at US$35,000 per month, plus US$20,000 for support, data processing, printing and miscellaneous. Total: US$125,000 per prospect, where needed.

Temperature-gradient drilling: Assume 6 slim-holes to average 600 m depth, at US$350 per m, plus US$75,000 for logging, data processing, printing and miscellaneous. Total: US$1,335,000 per prospect, where needed.

Modeling and site selection: Assume 3 man-months at US$15,000 per month, plus US$20,000 for support, data analysis and printing. Total: US$65,000.

In addition to the values given in Table IV-5, a project management function must be included, at an assumed cost of US$40,000 per month while operations are underway. This function will involve varied aspects of liaison, negotiation and permitting, field supervision, budget management, materiel control, documentation and reporting, plus other tasks as required, all of which can be time-consuming and complex in Kenya. Based on an assumed 12 months for all aspects of exploration and drilling, through to selection of sites for the initial 3 deep wells, this comes to US$480,000.

Note, however, that some exploration work has been done at specific prospects, and that selected exploration steps may be omitted at various prospects, because of geologic or terrain factors. This may reduce time and cost of the exploration stage by up to 20%. Also, for remote locations, costs will be increased by up to 20 or 25%, reflecting additional time and cost for mobilization, supply, communications, etc.

Therefore, the exploration cost may range from US$1,820,000 to 2,750,000 per prospect, depending upon the variables described above. This cost schedule has been applied to 15 prospects herein.

It is evident that the exploration cost per developed MW will be greater for small projects, and less for large developments. The exploration cost per project can be reduced by (a) selecting prospects that are less remote and less risky, (b) eliminating or reducing exploration steps, and (c) reducing the time requirements for exploration and drilling. Timetables for development are discussed in a subsequent section of this report.

3. Development Stage Costs

The items of greatest cost, in approximate descending order, are:

a. The power plant, including cooling towers, switching yard, and storage yard.

b. The wellfield, including production and injection wells, separators (if needed), steam gathering system and disposal lines.

c. Transmission line and substation.

d. Worker housing, offices, workshops, warehouses and related facilities.

e. Permanent water supply (wells, pipeline, storage tanks).

f. Road construction, site grading and other civil works.

g. Technical and economic feasibility studies, monitoring and testing, and design studies.

h. Preparation of specifications, selection of contractors, negotiation of agreements and permits, and supervision of contractors.

i. Environmental surveys and remedial work.

The power plant is discussed elsewhere. However, it should be noted that there are significant economies of scale in large developments; and that the enthalpy, chemistry, flow rate and pressure characteristics of the resource influence the type, size and cost of the power plant.

Experience at Olkaria and Eburru has shown that the initial exploratory wells are, on average, deeper and more expensive than subsequent production wells, both in absolute terms and per m drilled. Drilling costs (1990 US$) for wells of at least 6-inch bottomhole diameter are given in Table IV-6.

Table IV-6: Cost per Meter for Exploratory and Production Wells

Type	Depth, m	US$/m
Exploration	1,500 - 3,000	650 - 1,000
Production	1,200 - 2,400	500 - 750

This does not include the non-drilling costs of mobilization and demobilization (averages perhaps US$100,000 per well for small programs, to perhaps US$40,000 per well for programs of several wells), site preparation (about US$40,000 per well), road construction (averages perhaps US$20,000 per well for programs of several wells), or testing and data analysis (about US$40,000-100,000 per well, depending upon number of wells, location and reservoir complexity).

Additionally, it may be possible to obtain fluids from shallower depth at selected sites for binary-cycle generation. In such cases, production-well depth may average 300 to 800 m, at a cost of US$350 to 600 per m, depending upon well diameter and pump requirements. In this report, however, no field is estimated to be shallower than 1,000 m in depth. Mobilization, site preparation, roads and testing are additional.

Certain standardized assumptions can be made regarding drilling success rates, well yield, standby reserves, and injection wells, as follows.

Even in lower-risk prospects of Group 1 and 2, only 1 of the initial 3 exploration wells is likely to be commercially successful. For the higher-risk prospects of Group 3, and perhaps for certain others, the initial success ratio is likely to be 1 in 5. After a discovery has been made, 4 of every 5 subsequent wells in any group is anticipated to be commercially successful.

Approximately 1 injection well will be required for disposal of fluids from every 2 production wells. To achieve this, approximately 1 of every 2 unsuccessful wells can be converted into an injection well, at an additional expenditure of about 10% of its original drilling cost. Because of these anticipated success rates, a 10 MW development might require only 1 additional injection well; whereas, a 50 MW field might need 5 or 6 specially drilled injection wells. The exact number would vary with both the drilling success rate, the well yield and the requirement for standby reserve capacity.

A field cannot be operated safely for long without standby reserve capacity in wells. Otherwise, naturally occurring field pressure declines, or the need to shut-in a well for rehabilitation or repairs, would result in a reduction in power plant output. Typically, there should be standby reserve capacity equal to 10% of gross generating capacity or 1 additional well, whichever is a larger number of MW.

Table IV-7: Drilling Requirements for 10, 20 and 50 MW Developments

	Development Size, MW 10	20	50
Production wells	4	7	17
Injection wells	2	4	9
Dry holes	2	2	4
Standby production wells	1	1	2
Total	9	14	32

Table IV-7 gives the number of holes anticipated for a successful 10, 20 and 50 MW development, with suitable standby reserves, based on the assumption of a lower-risk prospect having an average yield of about 3 MW per well.

Table IV-7 shows a significant economy in scale for larger projects. The necessity to round fractional numbers to the next-largest integer (there cannot be 1/3 or 1/2 of a well), adds to this apparent benefit of scale.

Using an assumed average of 3 MW per well, and the values given earlier for drilling cost (US$650 - 1,000 per m for exploration holes, and US$500 - 750 per m for production and injection wells, as a function of well depth), a generalized cost of drilling the exploration and production wellfield is given in Table IV-8 for 10, 20 and 50 MW developments for wells of 1,000, 1,500, 2,000, 2,500, and 3,000 m depth.

Based on Table IV-8, Table IV-9 presents the range of drilling costs per MW developed, in US$/MW, again using 3 MW per well as average yield.

Table IV-8. Costs of Exploratory and Development Drilling, US$ Million

Table 8: Costs of Exploratory and Development Drilling, US$ Million

Development Size, MW

Row axis: Average Well Depth, m & Cost/m, US$

	10		20		50	
	Exploration	Development	Exploration	Development	Exploration	Development
Number of Wells:	3	6	3	11	3	29
1,000 @						
650/m	1.95		1.95		1.95	
500/m		3.0		5.5		14.5
TOTAL	*4.95*		*7.45*		*16.45*	
1,500 @						
650/m	2.925		2.925		2.925	
500/m		4.5		8.25		21.65
TOTAL	*7.425*		*11.175*		*24.575*	
2,000 @						
800/m	4.8		4.8		4.8	
600/m		7.2		13.2		34.8
TOTAL	*12.0*		*18.0*		*39.6*	
2,500 @						
950/m	7.125		7.125		7.125	
700/m		10.5		19.25		50.75
TOTAL	*17.625*		*26.375*		*57.875*	
3,000 @						
1,000/m	9.0		9.0		9.0	
750/m		13.5		24.75		65.25
TOTAL	*22.5*		*33.75*		*74.25*	

1991, GeothermEx, Inc.

Table IV-9: Drilling Cost per MW Developed, at 3 MW/Well Average Yield, in US$/MW

Average Depth, m	Development Size, MW 10	20	50
1,000	450	373	329
1,500	743	559	429
2,000	1,200	900	792
2,500	1,763	1,319	1,158
3,000	2,250	1,688	1,485

Table IV-9 shows the great sensitivity of cost to well depth. It reinforces the desirability of developing a low-risk, large, relatively shallow prospect.

Water supply during the exploration drilling phase can be supplied by tank trucks from wells or rivers. During field development, either well(s) must be drilled on-site/close by, or a pipeline must be constructed from an existing permanent water source. A water well is estimated to cost about US$100,000 including pump. Storage tanks cost perhaps another US$100,000, erected. By contrast, a water pipeline may cost US$100,000 per km, depending upon terrain, length and pumping requirements.

The testing and monitoring program necessary to prove the resource feasibility, plus the feasibility studies, and preparation of documents on system design bidding specifications, and contracts do not vary markedly by project size in the range 10 to 50 MW. For this report it is assumed that the cost increases by 0.2 for each 10 MW increment above a basic 10 MW unit size. Total cost therefore, is anticipated to be US$600,000 to 1,250,000 for projects of 10 to 50 MW size.

Civil works, including road construction, pad and plant site grading, and construction of holding ponds, retaining walls and the like will vary widely with project size and location. Pad costs are about US$20,000 per well; road construction is about US$7,000 per km for unpaved, unsurfaced roads.

Environmental surveys and remedial work herein is budgeted at the same cost for every project, because the issues of erosion, waste discharges, change of land use, water consumption and loss of animal habitat are essentially similar across the Rift Valley. A cost of US$100,000 is assumed for a 10 MW project, increasing to about US$250,000 for a 50 MW project.

The pro rata costs of rig mobilization, water supply, site preparation, road construction, environmental protection, and well testing and analysis operations ("non-drilling costs") are listed in Table IV-10.

Table IV-10: Pro-Rata Cost (US$) of Items Associated with Drilling ("Non-Drilling Costs") for 10, 20 and 50 MW Developments

Cost Item, US$	Development Size, MW 10	20	50
Mobilization	700,000	900,000	1,300,000
Site Preparation	350,000	600,000	1,300,000
Access Roads	350,000	400,000	500,000
Water Supply	200,000	400,000	750,000
Environmental	100,000	150,000	250,000
Testing & Analysis	600,000	800,000	1,250,000
Total	2,300,000	3,250,000	5,350,000
Number of holes drilled	9	14	32
Non-drilling cost per hole	255,000	232,000	167,000
Cost per kW	230	162	107

These costs essentially are independent of reservoir depth and well yield. Applying these values to hypothetical 1,500 and 2,000 m deep reservoirs, with yields of 3 MW per well, one obtains the total cost of wellfield for a prospect of average accessibility and complexity (Table IV-11).

Prospects located far to the north of Lake Baringo (including Namarunu, Emuruangogolak, Silali and Paka of Group 1) will carry an additional cost penalty for road construction, rig mobilization, resupply and communications, and possibly for water supply. This cost penalty may range up to 20% to 50% of the non-drilling costs (again proportionately greater for the smaller development), which in turn ranges from under 12% to over 22% of total wellfield cost. By this methodology, a cost penalty of as much as 10% or 12% has been applied to development of the more-remote prospects.

Transmission-line cost will vary with distance and line voltage. In general, lines suitable to transport 50 to 100 MW of electricity several tens of km at acceptable levels of loss (132 kV) will cost about US$70,000 per km (about 1.5 km of line and towers per US$100,000 of budget). Lower voltage lines, suitable for smaller geothermal developments, will cost less: 62.5 kV is about US$45,000 per km, and 33 kV costs about US$30,000 per km. No provision is make for the costs to add or modify substations, to accommodate this electric power.

Housing, offices, workshops and storage facilities will vary with project size, and to a lesser degree with the degree of project accessibility to other facilities. As a broad generalization, assuming 20 MW as the basic unit size for development, the cost for every additional 20 MW is assumed to be 0.25 additional to that of the basic unit cost. Thus, a 100 MW development will require such support facilities at a cost 2.0 times that of a 20 MW development.

Further, for remote fields, where no significant permanent settlement exists within about 10 or 15 km, and where haulage and construction costs thus are higher, 0.5 has been added to the cost of support facilities for the first unit (Table IV-12).

4. Operation Stage Costs

The cost of field operation consists of 5 major items:

a. Drilling of make-up or replacement wells, or the redrilling of existing wells: for a development of 10 to 50 MW size, estimate one drilling operation every 3 years, at approximately US $1,000,000 per drilling for wells of 1,000 to 2,000 m depth, and perhaps US$300,000 for shallow (moderate-enthalpy) fields; there probably is some cost sensitivity to project size.

b. Maintenance of existing wells and gathering lines: for projects of 10 to 50 MW size, assume US$50,000 per well annually for labor, supplies and equipment to be used in testing, sampling, monitoring and routine maintenance operations; assume US$100,000 per year for monitoring and maintenance of gathering and disposal lines; there probably is minor sensitivity to project size.

c. Office and warehouse operations: assume US$200,000 per year for labor, supplies and equipment to be used in maintenance of documentation, telecommunications, reporting, and resupply; there is some cost-sensitivity to project size.

d. Connection of new wells into the system: again for 10 to 50 MW development, assume US$100,000 per well, once every 3 years.

e. Miscellaneous: exploration for new resource areas; road maintenance; environmental or other remedial work; refurbishment of offices and equipment; purchase of vehicles and other equipment; assume US$250,000 per year; there is some cost-sensitivity to project size.

On the assumed basis of 3 MW per well, allowing for injection and standby reserve wells and for minor cost-sensitivity as a function of project size, a 10 MW field operation would cost about US$1.2 million annually, whereas a 50 MW field operation would cost approximately US$1.6 million annually.

G. PROJECT TIMETABLE

Project time requirements will vary with location, accessibility, degree of prior work, complexity of reservoir, and development size. The time requirements can be evaluated best by dividing the project into 3 segments: exploration, wellfield development, power plant construction. Other factors, such as water-supply development, environmental protection, feasibility reporting, or construction of on-site housing, are carried out during one or more of the exploration, wellfield development and power plant construction phases.

It is not realistic to draw detailed chronograms showing step-by-step activities, because each prospect has unique characteristics that affect both time and cost. Some generalizations can be made, however, as follows:

1. Exploration Timetable

6 to 18 months will be required for all surface exploration, including the drilling of up to 6 slim holes for temperature observation purposes. The longer time will be required where access is difficult, no (or very limited) prior work has been accomplished, prospect area is large, and an obvious central focal point for drilling is lacking or obscured. In selected cases where access is good, existing data are adequate and drilling targets are clear, the temperature-gradient drilling can begin within one or two months of project initiation. In that situation, the smaller number (6 months) may be achievable. For the hypothetical average project, 10 months is used. If results are not encouraging, the project may be terminated at this point.

2. Wellfield Development Timetable

This stage may begin immediately upon completion of exploration, or may lag by some undetermined period of time, reflecting contingencies of permitting, finance and project management. An initial 3 wells will be drilled, to discover the resource and allow an initial quantification of the reservoir. This will be done regardless of ultimate project size. Depending again upon factors of location and accessibility, and presumed reservoir depth, a period of 8 to 12 months is estimated for siting and well design, road and pad preparation, selection of a drilling contractor, mobilization, drilling, logging and testing of these 3 wells. Depending upon result, the project may be abandoned, or may continue into development drilling. However, it is assumed herein that wellfield development will continue almost immediately after completion of the initial 3 wells.

Unlike exploration, development drilling is dependent upon the anticipated size of the power plant. Therefore, assuming hypothetical 10, 20 and 50 MW initial developments, at an average

3 MW per well, the required time for all necessary drilling, testing and preparing feasibility reports is estimated to be as follows:

10 MW: 12 to 18 months (one rig)
20 MW: 24 to 36 months (one rig)
50 MW: 34 to 50 months (two rigs)

Concurrent with this, there may be construction of roads, the power plant site, housing for workers, and an office and workshop. There may be further surface exploration, or additional analytical studies. Preliminary power plant design, preparation of specifications, calls for bids on the power plant, and surveying transmission line right-of-way will begin long before the wellfield drilling is completed.

3. Power Plant Construction Timetable

Based on recent geothermal developments in the United States, Mexico and the Philippines, it is estimated that the final design, selection of manufacturer, manufacture, shipping, erection and acceptance testing of a power plant can be accomplished as follows:

10 MW: 12 to 18 months
20 MW: 18 to 24 months
50 MW: 18 to 36 months

This estimate is based on utilization of readily available ("off-the-shelf") and standardized power plants. No unusual design characteristics or unit sizes are anticipated.

The power plant stage would overlap broadly with the wellfield development, such that wellfield, transmission line, and other infra-structure would be completed essentially at the same time that the power plant is erected. Acceptance testing would follow immediately after the full interconnection of wells and plant.

4. Summary

From this outline, probable average timetables can be calculated (Table IV-13). It is assumed that wellfield development will follow immediately upon the exploration stage; and that the design and construction of a power plant will begin after 15 to 18 months of field development drilling, the exact time depending upon power plant size and reservoir complexity.

Table IV-13: Anticipated Time Required for Average 10, 20 and 50 MW Developments, Months

Development Size, MW		Exploration, months	+	Initial Wellfield, months	+	Power Plant, months	=	Total months
10	minimum	10		15		15		40
	maximum	18		15		18		51
20	minimum	10		15		18		43
	maximum	18		18		24		60
50	minimum	10		18		18		46
	maximum	18		21		30		69

These probable required times are not the absolute minimum values possible. That is, several months have been added into the wellfield development phase beyond the absolute minimum, as a safety factor. Even with this safety factor, it is calculated that plants of 10 MW can be brought on-line in 3-1/2 to 4 years from the initiation of exploration. Plants of 20 MW size would be operating in under 5 years; and 50 MW plants would require less than 6 years from the initiation of exploration.

For prospects in advanced stages of exploration (such as Menengai or Suswa) or exploratory drilling (Eburru) 6 to 20 months can be cut from these average time schedules.

It is assumed that the project will not be delayed because of regulatory, physical, environmental or financial constraints imposed within Kenya. Any undue constraints, relating to power pricing, land ownership, taxes or import duties, physical safety, or government decree could cause the project time to lengthen, perhaps significantly. Similarly, it is assumed that the project developer is prepared to proceed from phase to phase without hesitation if results are favorable.

H. PROJECT RECOMMENDATIONS

1. Factors Controlling Project Cost

Tables IV-3 and IV-4 assign priorities on the combined basis of potential resource size, risk, location and distance from transmission. Not surprisingly, Group 1A prospects form 5 of the top 6 priorities in these tables, reflecting the importance assigned to (a) anticipated low risk and (b) potentially large resource size.

Each prospect has a different range of anticipated exploration/development costs, reflecting location and accessibility, anticipated resource characteristics, and degree of prior exploration. These costs are described in section 6. In Table IV-14, the factors affecting cost are compiled for 15 of the 19 prospects listed in Tables IV-3 and IV-4 (4 very remote or environmentally protected sites are omitted). These factors are:

Size of possible initial power plant. There is great cost-sensitivity to power plant size. Therefore, those prospects having a resource potential of only 10 MW are at a disadvantage to those having significantly greater resource potential, all other things being equal. In Table IV-14, a probable plant size (10, 20 or 50 MW) is assigned to each of the 15 prospects on the basis of existing resource data. 50 MW is anticipated for Suswa, Korosi, Paka and Silali; Eburru, Longonot, Menengai, Arus, Olobonita and Chepchok are assumed to be 20 MW; all others are 10 MW.

Probable reservoir temperature. Prospects with probable temperatures of 180°C or less will be developed by binary-cycle methodology. Those with temperatures over about 210°C can effectively be developed by the flash-steam methodology.

Prospects having temperatures between about 180° and 210°C can utilize flash-steam process, but at a distinct cost disadvantage relative to either higher-temperature (flash) or lower-temperature (binary) fields. Indeed, a 10 MW binary-cycle plant for a reservoir of 165°-180°C yielding about 3 MW per well apparently is cost-competitive with 10 MW flash-steam plants at reservoirs of up to 300°C.

Drilling depth. Yield per well and drilling success rates have been discussed previously. Because of very limited reservoir data, these factors are held constant for all prospects under consideration. Therefore, wellfield cost will vary principally with well depth. Probable drilling depths from 1,000 to 1,750 m have been assigned to each prospect.

Transmission distance. As discussed previously, prospect distance from the KPLC grid varies from a few km to over 100 km. Prospects on islands or at sites over 100 km from the grid have been eliminated from further consideration. At the Lake Magadi prospect, the soda ash plant and local population is considered as a possible market for up to 10 MW; therefore, the transmission distance of only 15 km is used. All other prospects are assumed to supply the grid.

Prior Exploration. The extent and effectiveness of previous exploration activities (geologic mapping, gravimetry, fluid geochemistry, logging of existing wells, drilling of temperature-gradient holes, etc.) has varied widely. A cost penalty has been charged against Korosi, Paka, Silali, Chepchok, Loruk, Homa Mountain, Mwananyamala and Kapedo/Lorusio. There has been a deduction from exploration cost at Eburru, Suswa, Longonot and Lake Magadi, where target selection can proceed rapidly and without much further work. Menengai, Arus and Olobonita are not affected.

Remoteness of Prospect. Prospects lacking road access, permanent water supply, or easy access to a town and/or supply facilities will experience increases in overall project costs. Additional roads, camps, and water tanks or pipelines will have to be built. Distance from towns, and especially from Nairobi, will result in costly additional travel on the part of all project workers and suppliers. Silali and Paka are penalized the most for remoteness, followed by Korosi, and then by Chepchok and Longonot. Menengai, Eburru and Lake Magadi are given a cost deduction because of their close proximity to necessary facilities. Other prospects are unaffected.

Operational Complexity. A variety of factors that can make exploration, drilling and development more complex, and therefore more costly, includes geologic complexity, terrain roughness within the prospect, prospect size, and environmental constraints. The cost penalty principally reflects the additional months of operations necessitated by these factors. Suswa, Korosi, Paka and Silali in Group 1A, Longonot and Menengai in Group 1B, Olobonita in Group 2, and Homa Mountain, Mwananyamala and Kapedo/Lorusio in Group 3A are penalized.

Table IV-14. Factors Affecting Exploration and Development Cost

Risk Group & Prospect	Possible Initial Development, MW	Probable Reservoir Temperature, °C	Drilling Depth, m	Transmission Distance, km	Prior Exploration, ±% Cost	Remoteness[2] Factor, ±% Cost	Operational[3] Complexity, ±% Cost
1A							
Suswa	50	300	1,700	35	-10	-	+5
Eburru	20	285	1,600	13	-20	-5	-
Korosi	50	>240	1,200	90	+5	+10	+5
Paka	50	>240	1,500	100	+5	+12	+5
Silali	50	>240	1,250	100	+5	+12	+5
1B							
Longonot	20	>240	1,750	10	-5	+5	+5
Menengai	20	>240	1,250	6	-	-5	+5
2							
Arus	20	200-215	1,200	45	-	-	-10
Olobonita	20	170-190	1,300	15	-	-	+5
Chepchok	20	150-215	1,150	100	+5	+5	-5
Loruk	10	150-215	1,150	85	+5	-	-5

Table IV-14. Factors Affecting Exploration and Development Cost (continued)

Risk Group & Prospect	Possible Initial Development, MW	Probable Reservoir Temperature, °C	Drilling Depth, m	Transmission Distance, km	Prior Exploration, ±% Cost	Remoteness[2] Factor, ±% Cost	Operational[3] Complexity, ±% Cost
3A							
Lake Magadi	10	100-140	1,000	15[1]	-5	-5	-
Homa Mountain	10	179-200	1,100	60	+5	-	+5
Mwananyamala	10	152-180	1,100	60	+5	-	+10
Kapedo/Lorusio	10	155-172	1,100	90	+5	-	+10

Notes: (1) Local market; alternatively, 80 km to transmission grid.
(2) Road access; water supply; infrastructure in place.
(3) Prospect size and geologic complexity; terrain within prospect; effect upon timetable; pumping requirement for lower-enthalpy system.

2. Calculation of Cost Per Prospect

For each of the 15 remaining prospects, cost has been calculated on the following basis:

Exploration: The basic exploration cost (see Section IV-E2) is applied to each prospect; this cost is increased or reduced to reflect prior exploration activity, as indicated in Table IV-14.

Wellfield Development: This includes drilling and non-drilling (roads, mobilization, well testing, etc.) components. Drilling cost is a function of project size (10, 20 or 50 MW) and well depth, whereas non-drilling costs are a function only of project size (see Section IV-E). All drilling is presumed to cost US$650/m for the initial 3 exploratory wells, and US$500/m thereafter, as shown in Table IV-8. To this is applied a penalty (or, in a few cases, a cost reduction) of up to 17% for prospect remoteness and operational complexity.

Power Plant Construction: Power plant cost, as determined by The Ben Holt Company, is a function of plant size, resource temperature and generation mode (binary or flash cycle). It is noted, however, that cost will vary widely for prospects in the temperature range 180° - 220°C depending upon generation mode. The present assumption is that flash-cycle generation will be used, because of the temperatures expected. If, however, fluids of 165° - 180°C are produced at certain prospects (Chepchok and Loruk for example), instead of 180° - 210°C, power plant costs could be higher than those shown in these scenarios. Alternatively, if temperature reaches 215°C (for example at Arus), power plant costs may be reduced somewhat. These values, taken from Ben Holt, are summarized in Table IV-15.

Transmission Lines: Costs are based on average Kenya costs for a 132 kV line, without regard to any special terrain or environmental factors. It is recognized that a 132 kV line may not be needed initially at every prospect, but this is not factored into the cost estimate.

Gathering System: The cost of the steam-gathering and disposal pipelines, and auxiliary equipment, has been determined by The Ben Holt Company for 10, 20 and 50 MW power plants based on comparable developments in the United States and elsewhere.

Owner's Cost and Financing Charges: This includes project management cost, cost of constructing support facilities, permitting and licensing fees, and finance charges during wellfield and power plant construction. These cost data are provided by The Ben Holt Company. However, the costs of feasibility reports have already been included under wellfield development, and are not repeated herein. A cost penalty of about 12% is applied to the more remote sites, for which additional lead-time (and therefore additional financing costs) are required.

Table IV-15. Cost of Power Plant, US$ Million and US$/kW

Power Plant Size, MW

Reservoir Temperature, °C	5	10	20	50
300	-	24.3/2,430	31.7/1,585	54.8/1,096
285	-	24.4/2,440	31.8/1,590	55.0/1,100
240	-	24.6/2,460	32.3/1,615	56.1/1,122
200	21.1/4,220	25.2/2,520	33.4/1,670	
180	21.2/4,240	25.55/2,555	34.0/1,700	
Flash Cycle				
Binary Cycle				
165	10.2/2,040	16.3/1,630		
140	12.3/2,460	23.1/2,310		

Cases considered in this report.

Table IV-16. Total Cost (US$), Cost Per kW (US$/kW), and Ranking for Development

Prospect (Anticipated Initial Development MW)		Exploration, Field Development, Infrastructure & Feasibility	Permitting, Power Plant Transmission Gathering System Owner's Cost & Financing	Total	Risk Group	Overall Rank	Within Risk Group
Suswa	(50)	31,847,000 637	75,350,000 1,507	107,197,000 2,144	1A	1	1
Korosi	(50)	25,599,000 512	82,191,000 1,644	107,790,000 2,156	1A	2	2
Silali	(50)	26,957,000 539	82,875,000 1,658	109,832,000 2,197	1A	3	3
Paka	(50)	31,768,000 635	82,875,000 1,658	114,643,000 2,293	1A	4	4
Eburru	(20)	13,532,000 667	39,811,000 1.990	53,343,000 2,667	1A	6	5
Menengai	(20)	12,073,000 604	39,837,000 1,992	51,910,000 2,596	1B	5	1

Table IV-16. Total Cost (US$), Cost Per kW (US$/kW), and Ranking for Development (continued)

Prospect (Anticipated Power Plant Size MW		Exploration Field Development, Infrastructure & Feasibility	Permitting, Power Plant Transmission Gathering System Owner's Cost & Financing	Total	Risk Group	Within Risk Group	
Longonot	(20)	15,660,000 783	40,111,000 2,006	55,771,000 2,789	1B	8	2
Arus	(20)	10,806,000 540	44,113,000 2,206	54,919,000 2,746	2	7	1
Olobonita	(20)	12,929,000 646	43,058,000 2,153	55,987,000 2,799	2	9	2
Chepchok	(20)	11,466,000 573	49,572,000 2,479	61,038,000 3,052	2	10	3
Loruk	(10)	8,306,000 831	35,315,000 3,531	43,621,000 4,362	2	15	4
Mwananyamala	(10)	8,888,000 889	26,301,000 2,630	35,189,000 3,519	3A	11	1

Table IV-16. Total Cost (US$), Cost Per kW (US$/kW), and Ranking for Development (continued)

Prospect (Anticipated Power Plant Size, MW)		Exploration, Infrastructure & Field Development, Feasibility	Permitting, Power Plant Transmission Gathering System Owner's Cost & Financing	Total	Risk Group	Overall Rank	Within Risk Group
Kapedo/Lorusio	(10)	8,888,000 889	28,358,000 2,836	37,246,000 3,725	3A	12	2
Lake Magadi	(10)	7,325,000 733	32,351,000 3,235	39,676,000 3,968	3A	13	3
Homa Mountain	(10)	8,615,000 862	33,605,000 3,360	42,220,000 4,222	3A	14	4

These costs have been tabulated for each of the surviving 15 prospects in Table IV-16, under 3 categories: (a) costs relating to exploration, wellfield development, infrastructural development and feasibility reporting; (b) costs of permitting and licensing, power plant, transmission line, steam-gathering and disposal system, project management and finance charges during construction; and (c) total project cost. Costs are expressed in millions of US$ and as US$ per kW installed, for the sizes of power plant determined in Table IV-15.

It can be seen that:

1. Costs per kW are significantly lower for 20 MW than for 10 MW, and are lowest for 50 MW projects. This places the smaller, riskier prospects of Group 3A at a further disadvantage, and emphasizes the attraction of a potentially large resource.

2. Within each risk group (with the exception of Loruk, in Group 2), there is a maximum spread in cost per kW of about 25%; most prospects fall within a cost range of about 10% within their risk group. This percentage probably falls within the range of uncertainty associated with such factors as well depth, or with the cost surcharges for remoteness and operational complexity. This means that within each risk group subjective preference (based on experience elsewhere) may be the determining factor in selecting a prospect for development.

3. The critical cost parameters appear to be transmission-line distance, well depth, and resource size and risk. Therefore, the riskier prospects within Groups 2 and 3A can be considered only if well depth is anticipated to be shallow, and/or transmission distance is short.

4. The ideal prospect combines low risk (Group 1A or 1B) with large potential (50 MW power plant), shallow depth to reservoir and proximity to the transmission grid. No prospect fully meets these criteria. Suswa (lowest cost per kW) may come closest.

5. A project may be abandoned short of completion, perhaps even before drilling a significant number of exploration wells. Therefore, a minimum-risk strategy involves selection of the prospect(s) having the lowest cost and least operational complexity through the exploration stage, or through the exploration and initial drilling phase. The projects having lowest exploration and initial drilling costs include Lake Magadi, Arus, Eburru and (perhaps) Menengai. However, Lake Magadi is a small-size, low-temperature (to 140°C)

and high-risk prospect; Arus may be small and perhaps only of moderate temperature (to 215°C); Eburru has had disappointing drilling results to date; and Menengai does not present an immediately recognizable drilling target, thus requiring further exploration.

6. Costs for the least expensive prospects appear to be compatible with those of major geothermal fields in the United States and elsewhere. Cost trade-offs occur from country to country over such factors as well depth, prospect accessibility, environmental sensitivity, well yield, and existence of support infrastructure.

7. Only in 1 case does a Group 2 prospect appear to have lower development cost than a Group 1 prospect: Arus appears to be slightly easier (and therefore cheaper) to develop than Longonot. Both developments are anticipated to be 20 MW.

3. Favorable and Negative Aspects of Each Prospect

The favorable and negative aspects of each prospect are summarized by risk group in the following table:

Prospect (MW)	Comments
Group 1A	
Suswa (50)	Lowest anticipated cost per kW; accessible; probable very high-temperature resource; potentially very large; deep water table, therefore deep and costly drilling; no drilling target yet identified; moderate transmission distance; possible "fast-track" development timetable.
Korosi (50)	Low anticipated cost per kW; remote and poorly accessible; probable high-temperature resource; potentially very large; probable moderate well depth; no drilling target yet identified; long transmission distance; not on "fast-track" timetable.
Silali (50)	Low anticipated cost per kW; remote and poorly accessible; probable high-temperature resource; potentially very large; probable moderate well depth; no drilling target yet identified; very large transmission distance; not on "fast-track" timetable.

Paka (50)	Low anticipated cost per kW; remote and poorly accessible; probable high-temperature resource; potentially very large; moderately deep drilling anticipated; no drilling target yet identified; very long transmission distance; not on "fast-track" timetable.
Eburru (20)	Moderate anticipated cost per kW; accessible; largely explored; disappointing results in drilling; several drilling targets remaining, many at lower elevations; moderate to large resource potential; moderate to deep drilling; short transmission distance; possible "fast-track" timetable.
Group 1B	
Menengai (20)	Moderate anticipated cost per kW; accessible, but operationally may be complex; partially explored; probable high-temperature resource; moderate to large resource potential; probable moderate well depth; no drilling target yet identified; very short transmission distance; possible "fast-track" timetable.
Longonot (20)	Moderate anticipated cost per kW; moderately accessible; probable high-temperature resource; moderate to large resource potential; probable great drilling depth; no drilling target yet identified; very short transmission distance; possibly on "fast-track" timetable.
Group 2	
Arus (20)	Moderate anticipated cost per MW; accessible; not operationally complex; probable moderate to high resource temperature; moderate resource potential; probable moderate drilling depth; drilling target easily identified; medium transmission distance; probable "fast-track" timetable.
Olobonita (20)	Moderate anticipated cost per MW; accessible; possibly operationally complex; possible moderate to high resource temperature; moderate resource potential; probable moderate drilling depth; no drilling target yet identified; short transmission distance; probably not on "fast-track" timetable.

Chepchok (20)	Moderately high anticipated cost per MW; cost might be lower with binary cycle; remote and poorly accessible; probable moderate-temperature resource; shallow drilling anticipated; probable moderate resource size; no drilling target identified; very long transmission distance; not on "fast-track" timetable.
Loruk (10)	Highest anticipated cost per MW; cost might be lower with binary cycle; accessible, but poorly defined; probable moderate resource temperature; shallow drilling anticipated; resource size may be small; long transmission distance; not on "fast-track" timetable.

Group 3A

Mwananyamala (10)	High anticipated cost per kw; accessible, but not explored; potentially moderate-temperature resource; size may be small; drilling may be shallow; no drilling target yet identified; moderately long transmission distance; not on "fast-track" timetable.
Kapedo/Lorusio (10)	High anticipated cost per kW; accessible, but probably operationally complex; potentially moderate-temperature resource; size may be small; drilling may be shallow; no drilling target yet identified; long transmission distance; not on "fast-track" timetable.
Lake Magadi (10)	High anticipated cost per kW; accessible and well explored; moderate to low-temperature resource; may be small in size; drilling probably shallow; drilling target easily identified; short transmission distance to local market; otherwise moderately long transmission; possible "fast-track" timetable for local market.
Homa Mountain (10)	Very high anticipated cost per kW; cost might be lower with binary cycle; accessible, but operationally may be complex; probable moderate- temperature resource; size may be small; probable shallow drilling depth; no drilling target yet identified; not on "fast-track" timetable.

4. Project Recommendations

Based in the foregoing, the following recommendations are offered, in approximate decreasing order of attractiveness:

a. Suswa presents an attractive possibility of a large, rapidly explored and developable (but deep) resource.

b. Eburru offers an opportunity for immediate drilling and development of a resource of moderate potential.

c. Arus offers an opportunity for immediate drilling into a potential resource of moderate potential.

d. Menengai presents a less-immediate but potentially attractive opportunity for discovery of a moderate to large resource.

e. Korosi, Paka and Silali probably are large, high-temperature resources, requiring costly and time-consuming efforts to discover and develop.

f. No other site is immediately attractive for investment.

g. Lake Magadi would become attractive for immediate drilling if an adequate local market for electricity can be assured.

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Figure IV-1. Generalized Geologic Map of Kenya.

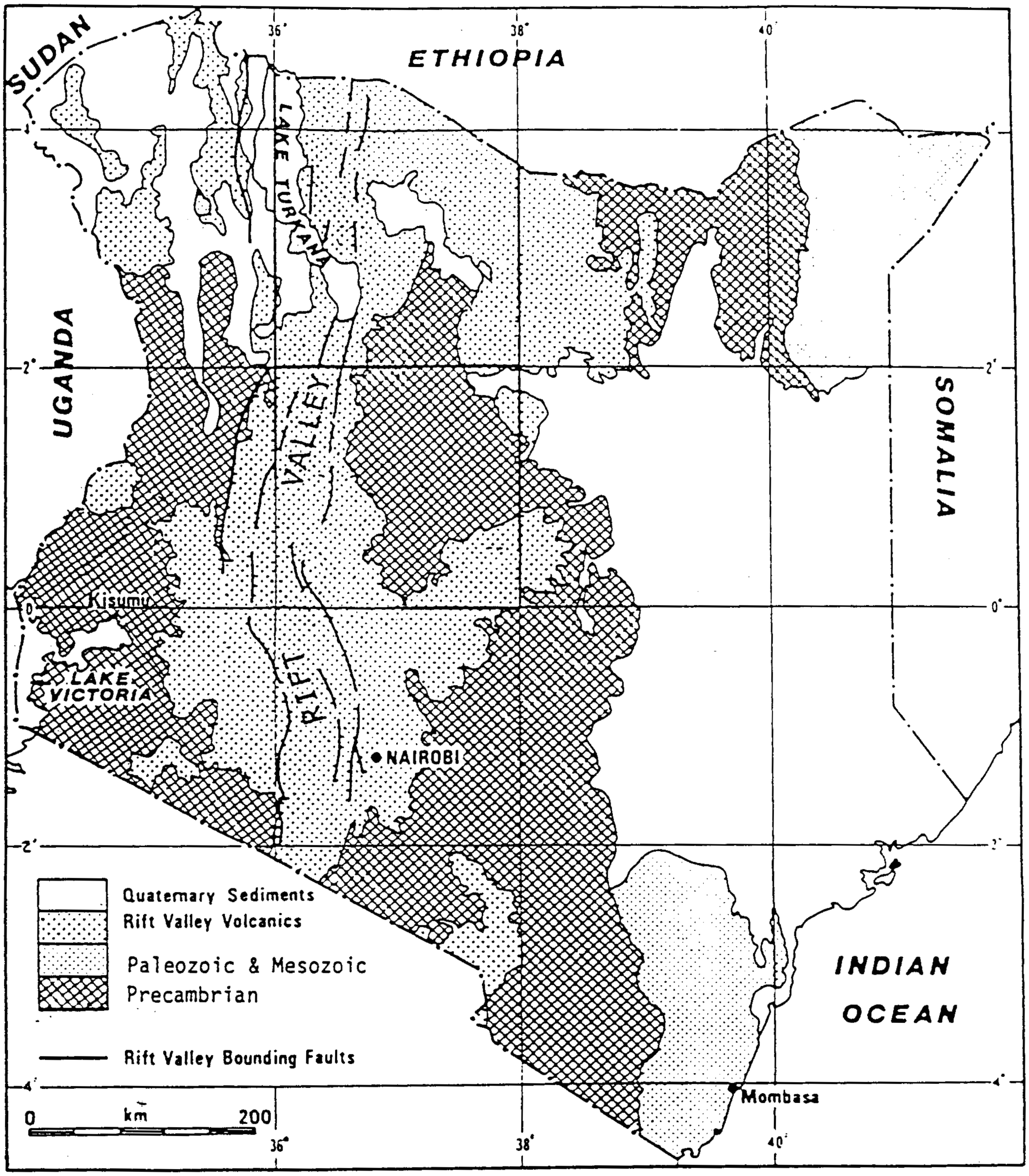


Figure IV-2. The East African Rift System.

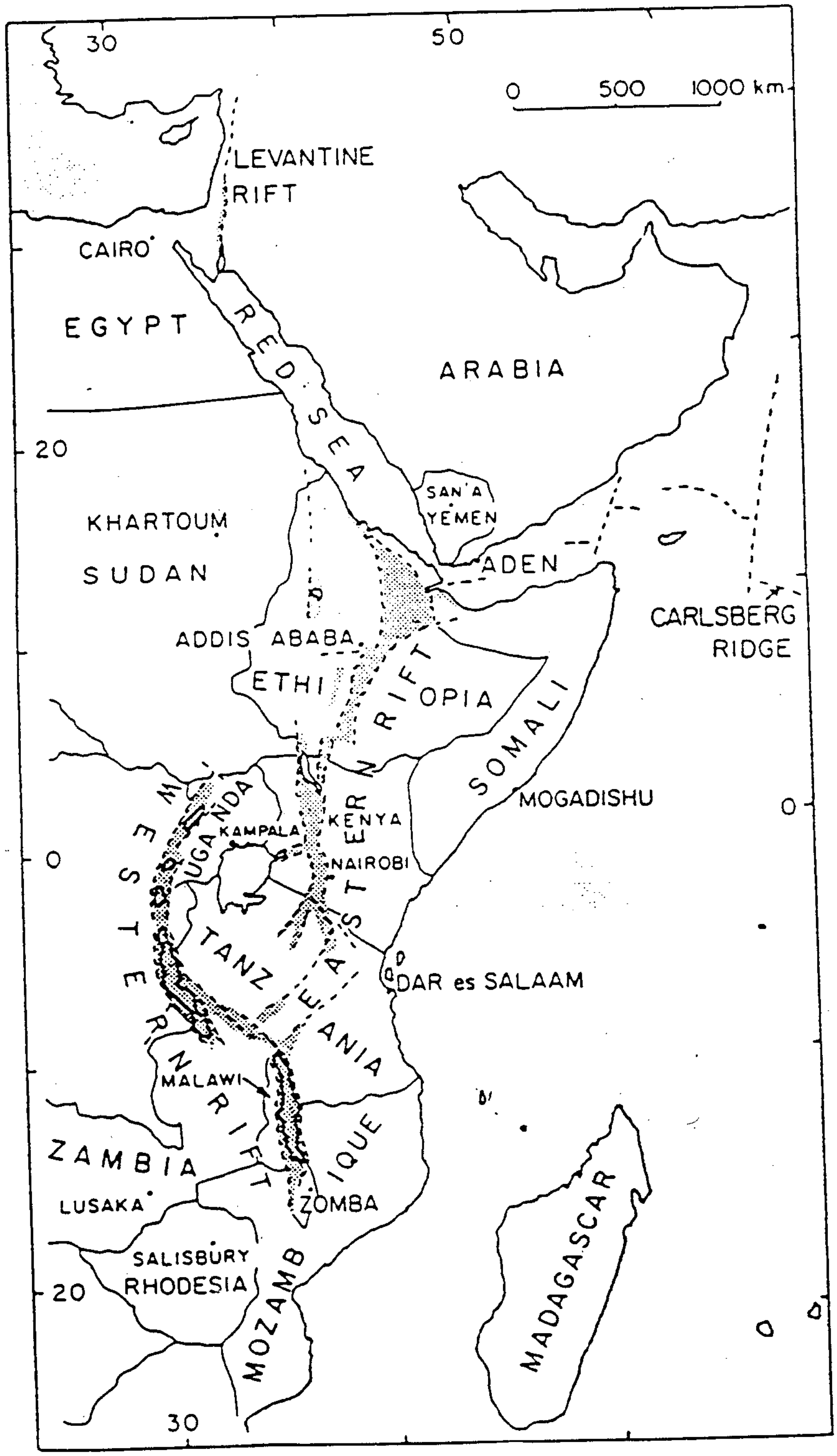


Figure IV-3. Geological Map of the Kenya Rift.

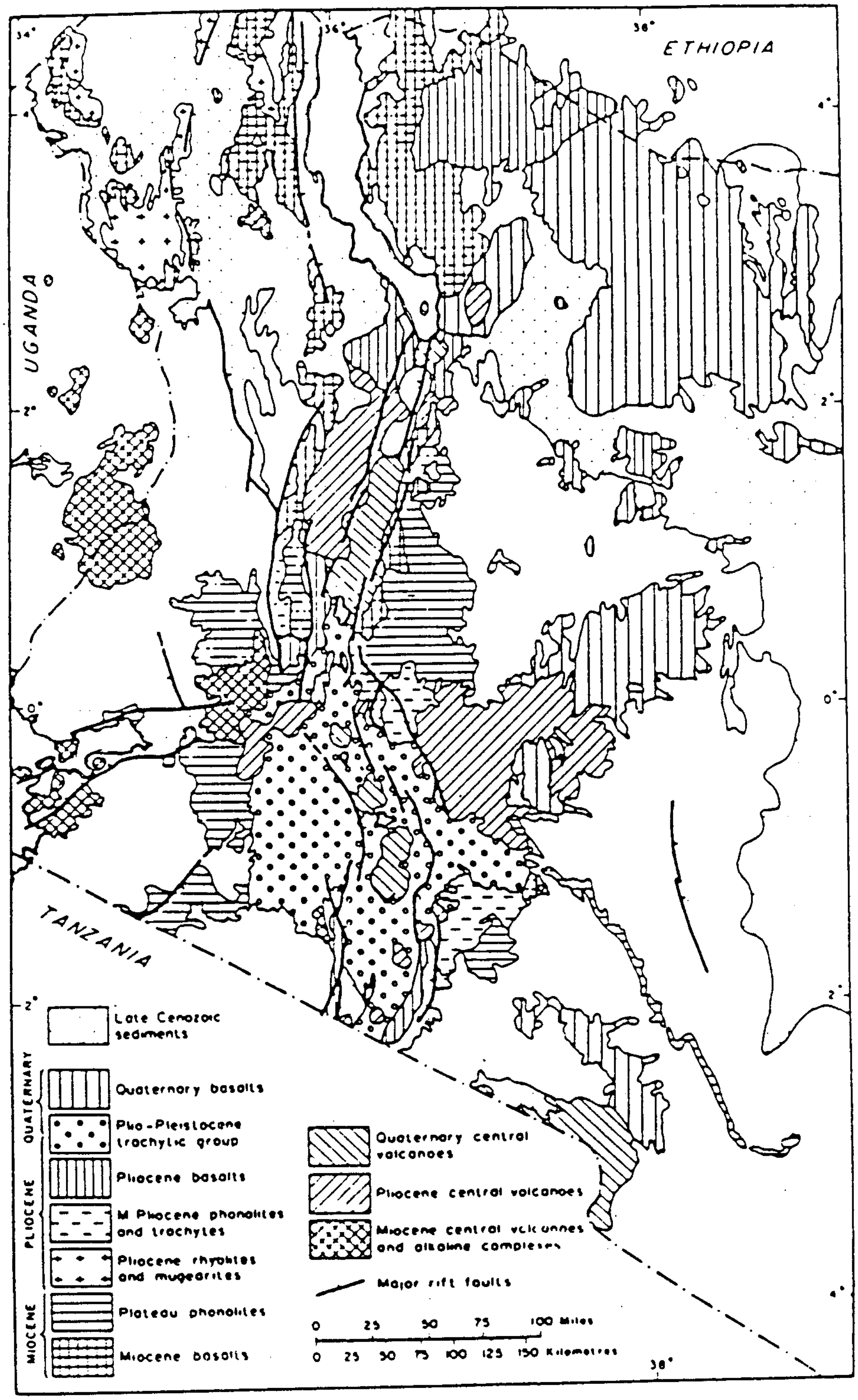


Figure IV-4. Fault Pattern of the Rift Valley.

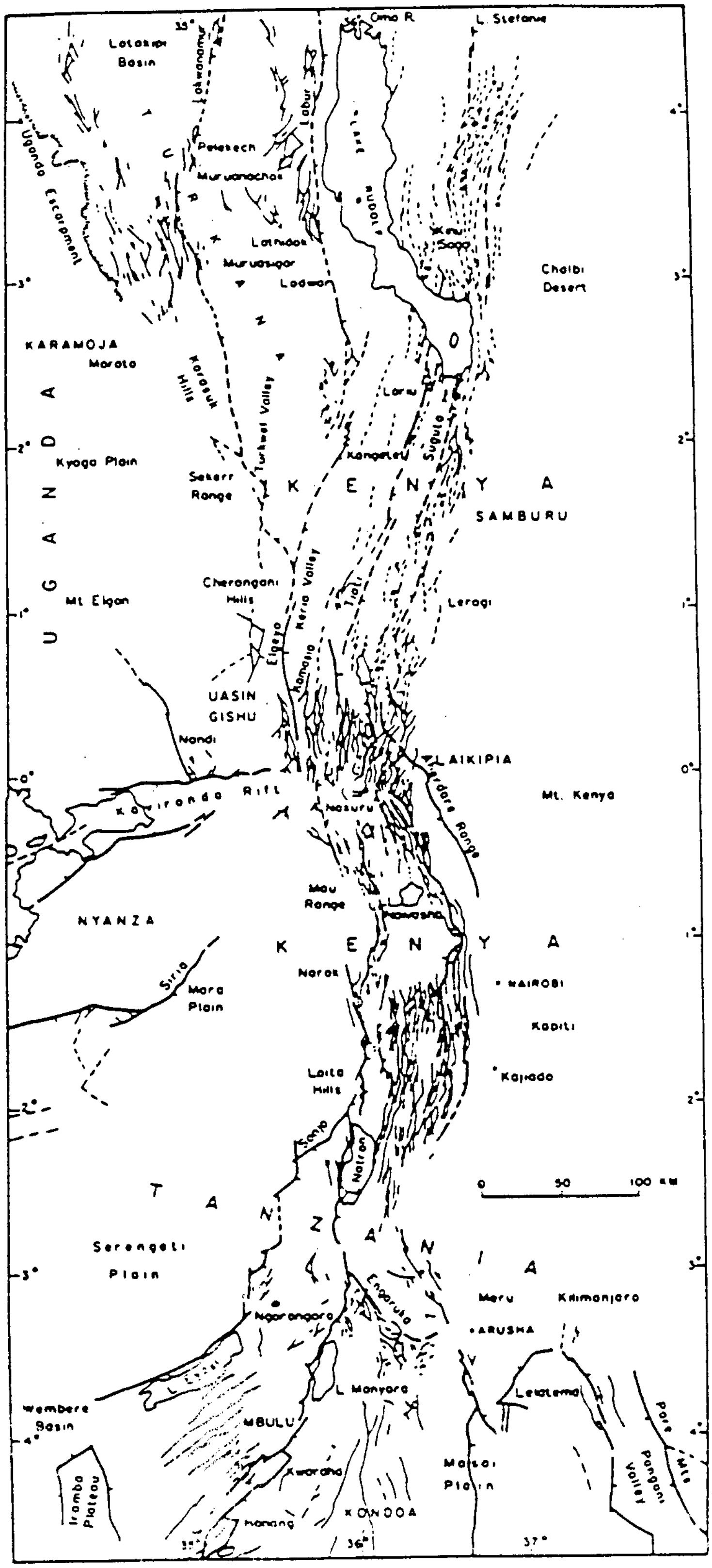
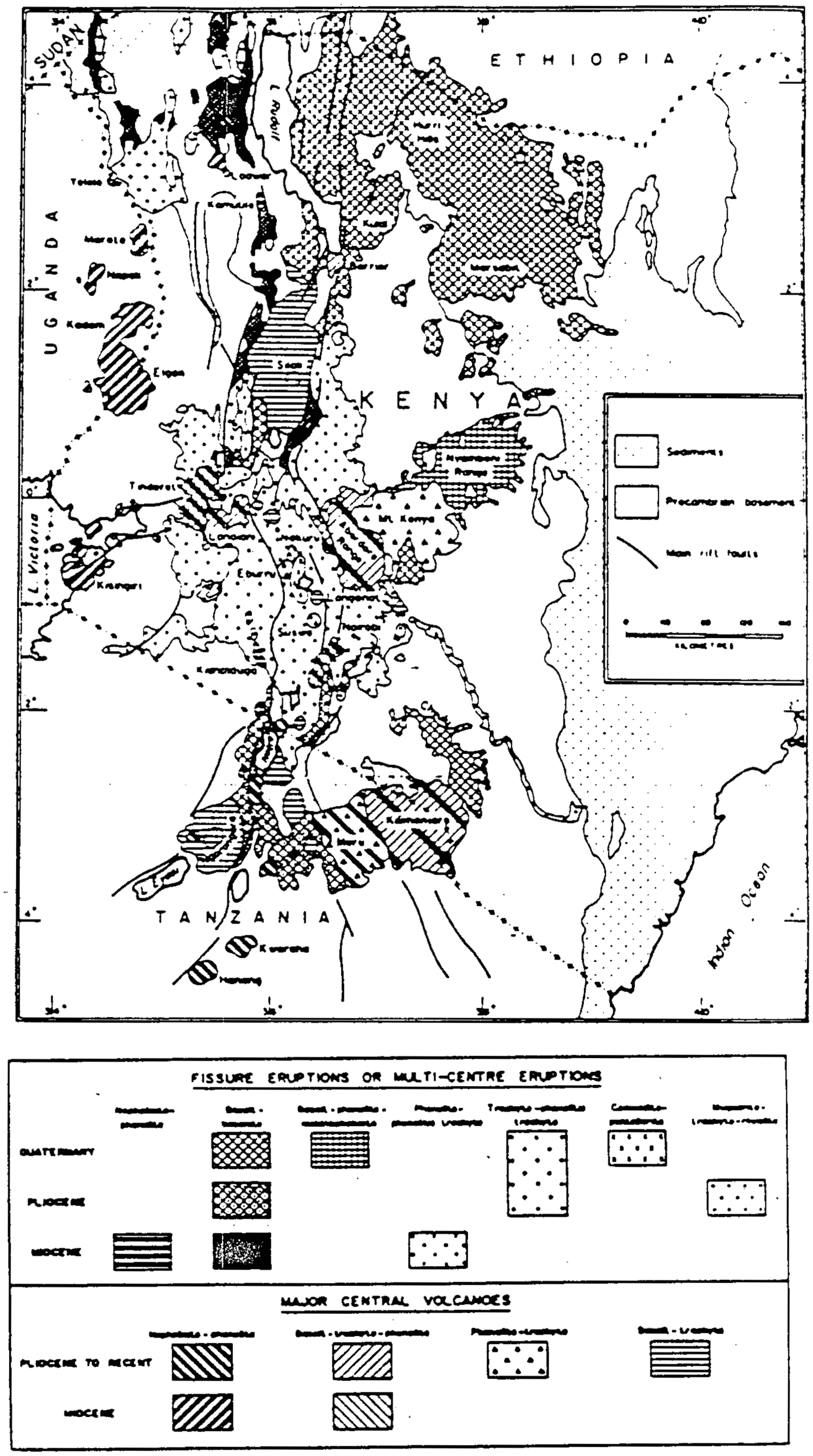


Figure IV-5. Map Showing the Distribution of the Main Volcanic Associations in Kenya, Eastern Uganda and Northern Tanzania.



Map showing the distribution of the main volcanic associations in Kenya, eastern Uganda and northern Tanzania (*After* WILLIAMS, 1969a, Fig. 1, p. 63, modified to distinguish Miocene, Pliocene and Quaternary volcanics).

Figure IV-6. The Distribution In Space and Time of Rift Volcanics.

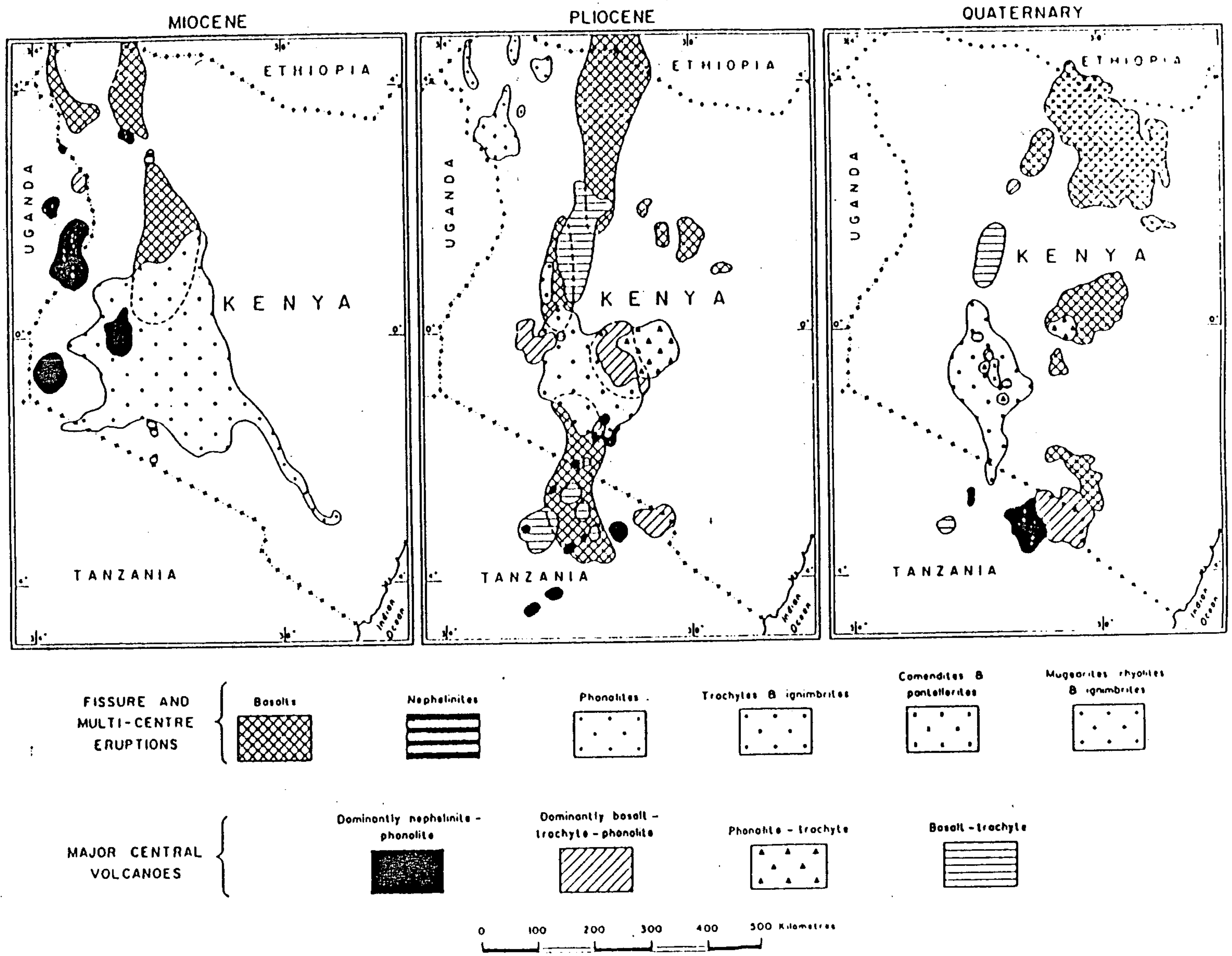


Figure IV-7. Major Late Tertiary and Quaternary Volcanoes.

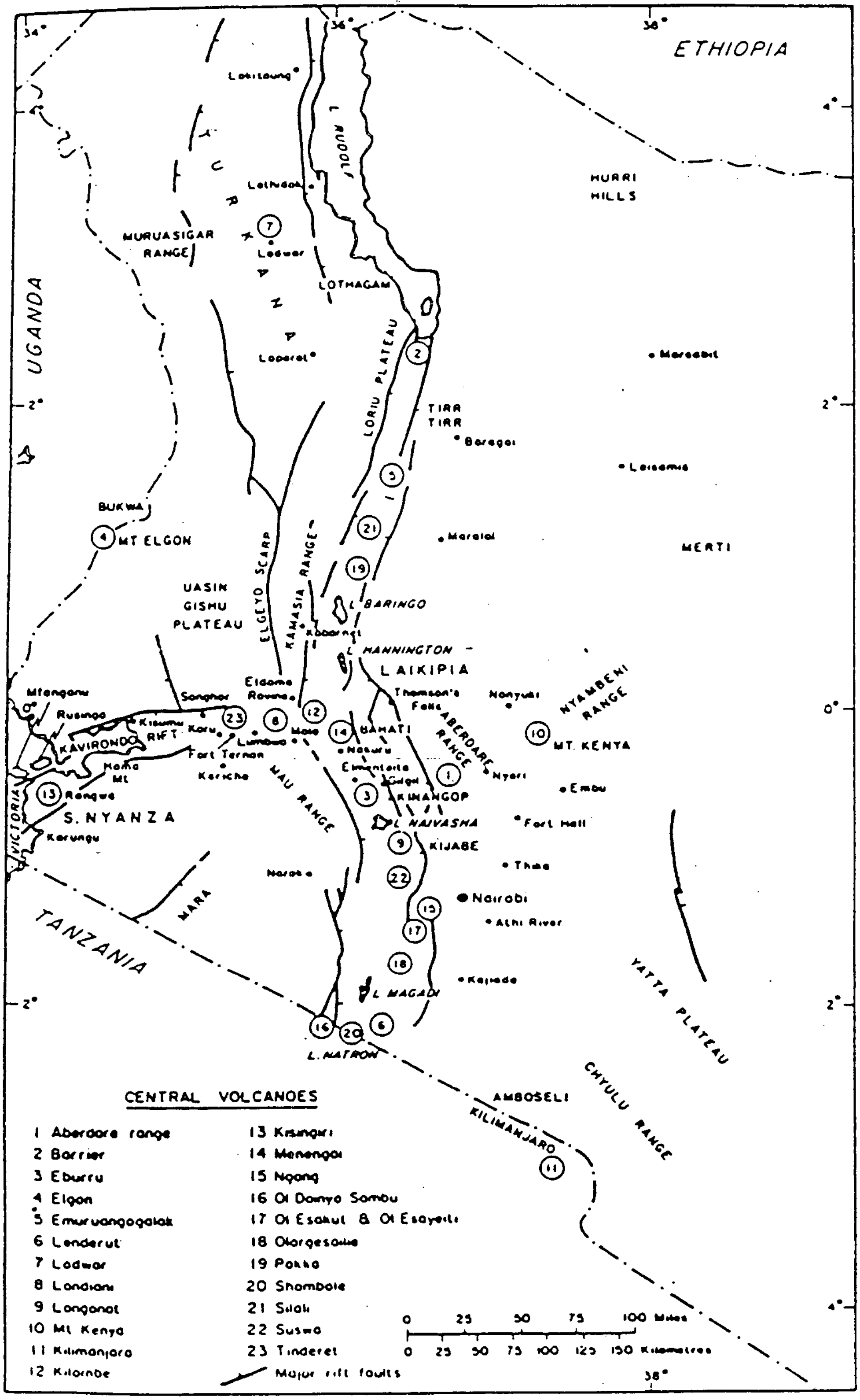


Figure IV-8. Map of Geothermal Prospects and Roads, Kenya.

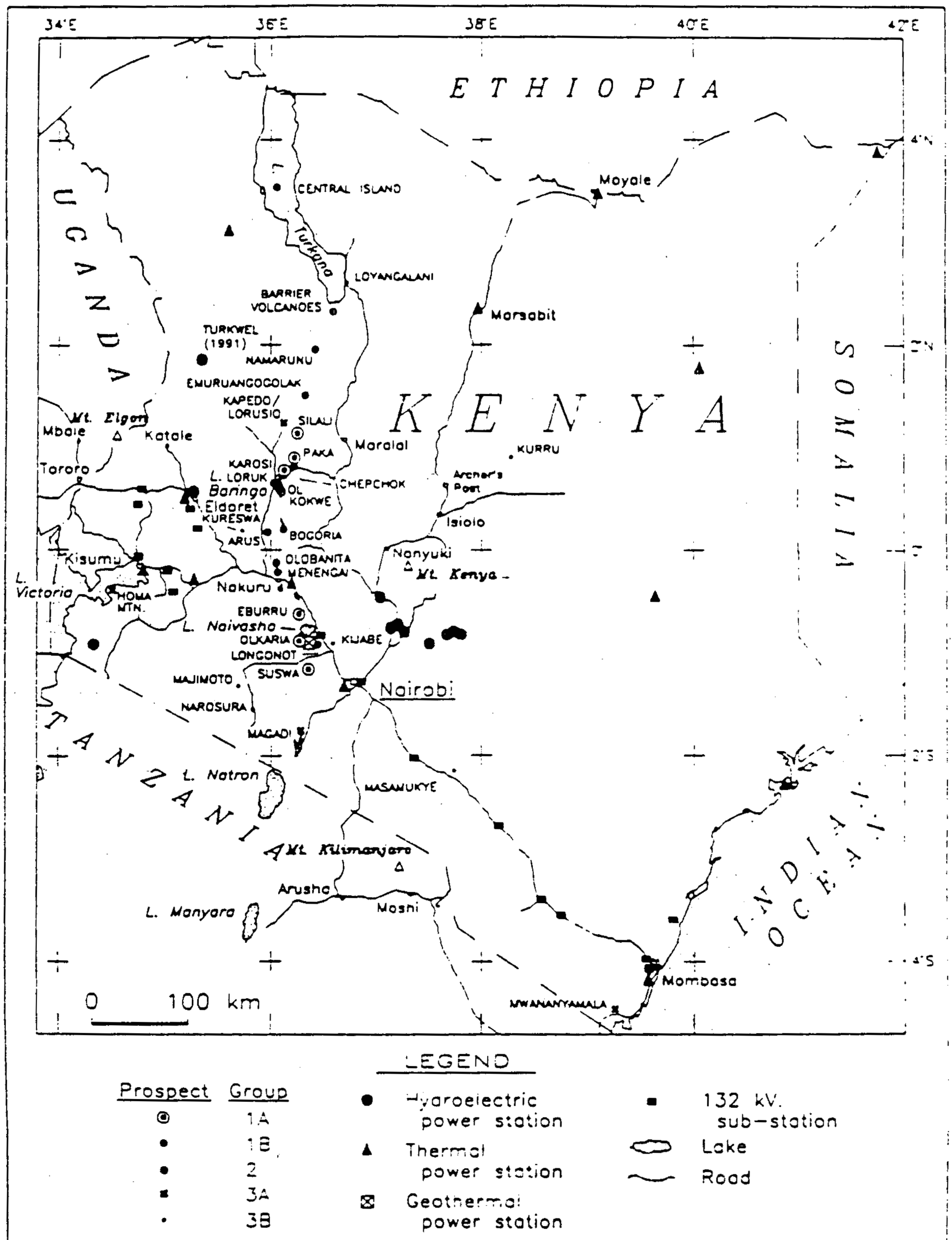


Figure 8: Map of geothermal prospects and roads, Kenya

1990, GeothermEx, Inc.

Figure IV-9. Map of Geothermal Prospects, Power Transmission Lines and Power Distribution Lines.

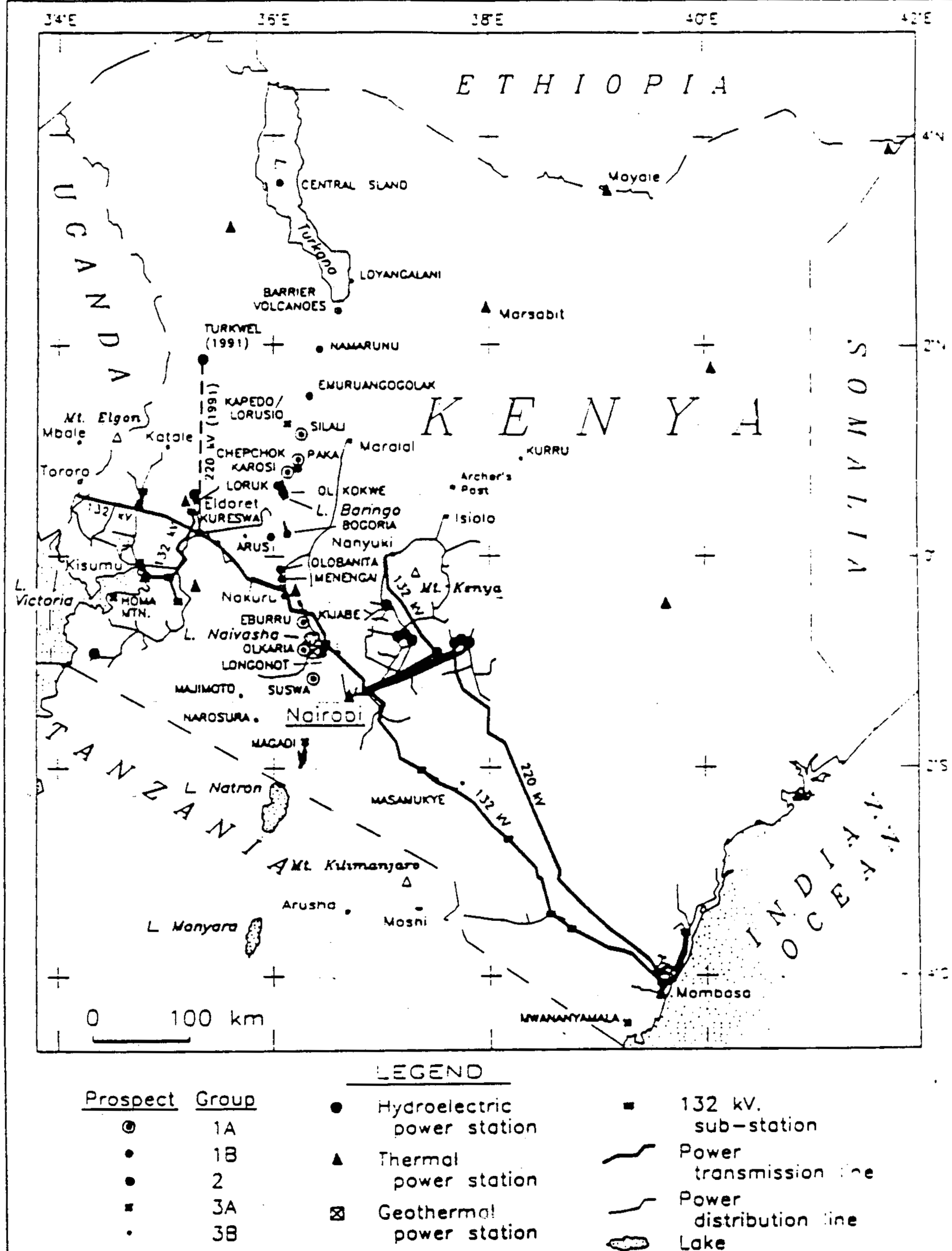


Figure 9: Map of geothermal prospects, power transmission lines and power distribution lines.

1990, GeothermEx, Inc.

Section V. CAPITAL COSTS AND TECHNICAL CHARACTERISTICS OF GEOTHERMAL POWER PLANTS

A. INTRODUCTION

The purpose of this section of the report is to estimate capital costs and O & M costs for the most attractive of the prospects identified in Section IV of this report. Descriptions are also provided of the basic geothermal power generation options. This is followed by a financial analysis of the prospective sites and generation technologies in Section VI.

1. Methodology

Section IV classified prospective resources in different ways. In Table IV-1 they were classified by level of exploration risk. In Table IV-2, resource characteristics were set forth, including area, temperature, depth to groundwater, distance to transmission line, distance to distribution line and distance to access road. Table IV-14 lists the important factors affecting project cost for fifteen prospects. In Table IV-16, the 15 selected prospects were ranked according to cost-per-kilowatt to identify the most likely areas of future development.

These tables are referenced herein and serve as a useful basis for our work, (The Ben Holt Company). These tables are important in that they take into account key factors in an evaluation of a prospect: namely, size, depth, temperature and location.

To build upon this basis we have taken into account the following costs:

* Power plant costs as a function of size and resource temperature.

* Gathering and injection system costs as a function of plant size, resource temperature and well productivity.

* Transmission line and access road costs as a function of distance to a transmission line or main road.

* Project costs, including siting, financing and owner's costs during construction.

An effort has been made to develop both capital and O & M costs on a consistent basis in order to provide meaningful relative values. These costs were then added to exploration and well drilling costs developed by others.

In general, at each prospect 3 plant sizes were investigated. For the steam flash prospects, 10 MW, 20 MW or 50 MW plants were studied. For the binary cycle prospects, 5 MW, 10 MW and 20 MW plants were used. For each case, a well productivity of 3 MW/well was assumed. This value represents the experience at the Olkaria reservoir and assumes that state-of-the-art large diameter drilling and completion technologies are able to increase productivities to a level comparable to other major resources. For the cases involving binary cycle plants, pumped wells were assumed. The productivity used was 1500 gpm/well, a value typical for western U.S. reservoirs.

2. Results

Table V-1 is a detailed summary of the cases studied. There were 12 prospects suitable for dual-flash steam plants and three prospects suitable for binary plants. These represent the prospects shown on Table IV-16.

Figures V-1 through V-3 present the capital costs for projects of 50, 20, and 10 MW respectively as stacked bargraphs. All the cases shown in these figures assume well productivities of 3.0 MW/well. From the figures, it can be seen that, for each plant size, the project costs, plant costs and gathering and injection system costs are nearly constant from one prospect to the next. However, the well costs, exploration costs, transmission line cost and access road cost vary from site to site. In the case of 50 and 20 MW plants, the variation in well costs has the greatest impact on overall cost while for 10 MW plants, the transmission line and access road costs are controlling.

Total costs and/or the cost per kW of a developed power plant can be seen to differ slightly from those given in Table IV-16, prepared by GeothermEx. These differences rarely exceed 4%, and in some cases are less than 1%. They reflect differences in treatment given to exploration and drilling costs and in costs of access roads, gathering systems and injection systems. The close similarity of values derived by different computations is encouraging, and suggests that these are useful values for development planning purposes.

Figure V-4 shows the variation of project unit costs with plant size. Only dual-flash steam plants are shown. The line on the graph represents the average unit cost for each plant size. The "knee" of the curve occurs at about 15 MW. Below this point, unit costs tend to escalate dramatically.

Binary-cycle plants have been studied for 3 prospects; Lake Magadi, Mwananyamala and Kapedo/Lorusio. Binary plants are modular by nature and composed of multiple turbo-generators. They can be economically built in sizes as small as 1 MW. However, the maximum module size for radial-inflow turbines is about 5 MW, and so a 50 MW plant would require 10 modules. This tends to put the modular plant at an economic disadvantage in the larger plant sizes.

Table V-1. Capital and O&M Costs for Selected Kenya Geothermal Prospects

Capital and O&M Costs
for
Selected Kenya Geothermal Prospects

Sheet No. 1 of 2
Job No. 10093
Date 11/27/90

Subject: Detail Summary — By JRB

Prospect:	Suswa	Korosi	Silali	Paka	Eburru	Menengai	Longonot	Arus	Olobonita
Case Data									
Plant Size, MW	50	50	50	50	20	20	20	20	20
Resource Temp., °C	300	240	240	240	285	240	240	200	180
Well Prod., MW/well	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Production Wells	17	17	17	17	7	7	7	7	7
Injection Wells	9	9	9	9	4	4	4	4	4
Spare Wells	2	2	2	2	1	1	1	1	1
Dry Wells	4	4	4	4	2	2	2	2	2
Well Depth, m	1,700	1,200	1,250	1,500	1,600	1,250	1,750	1,200	1,300
Exploration Factor	0.90	1.05	1.05	1.05	0.80	1.00	1.05	1.00	1.00
Remot. & Complex.	1.05	1.15	1.17	1.17	0.95	1.00	1.10	0.90	1.05
Investment									
Exploration	2,052,000	2,394,000	2,394,000	2,394,000	1,824,000	2,280,000	2,394,000	2,280,000	2,280,000
Prod. & Inj. Wells	34,980,750	28,853,500	30,317,625	35,129,250	14,411,500	12,562,500	17,916,250	10,974,000	13,581,750
Gath. & Inj. Syst.	5,197,000	5,421,000	5,421,000	5,421,000	2,154,000	2,169,000	2,169,000	2,694,000	3,199,000
Power Plant	46,666,000	47,533,000	47,533,000	47,533,000	28,411,000	28,759,000	28,759,000	29,579,000	30,102,000
Trans. Line	2,450,000	6,300,000	7,000,000	7,000,000	910,000	420,000	700,000	3,150,000	1,050,000
Access Road	0	870,000	1,492,000	2,237,000	0	622,000	124,000	249,000	0
Proj. Costs	13,250,000	13,250,000	13,250,000	13,250,000	5,300,000	5,300,000	5,300,000	5,300,000	5,300,000
Total	$104,600,000	$104,600,000	$107,400,000	$113,000,000	$53,000,000	$52,100,000	$57,400,000	$54,200,000	$55,500,000
($/kW)	($2,092/kW)	($2,092/kW)	($2,148/kW)	($2,260/kW)	($2,650/kW)	($2,605/kW)	($2,870/kW)	($2,710/kW)	($2,775/kW)
O&M Costs									
Wells	1,600,000	1,600,000	1,600,000	1,600,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000
Gath. & Inj. System	171,000	176,300	176,300	176,300	115,800	116,900	116,900	127,800	138,600
Power Plant	910,000	926,000	926,000	926,000	582,000	588,000	588,000	602,000	612,000
Transmission Line	25,000	63,000	70,000	70,000	9,000	4,000	7,000	32,000	11,000
Total	$2,706,000	$2,765,300	$2,772,300	$2,772,300	$2,006,800	$2,008,900	$2,011,900	$2,061,800	$2,061,600
(mills/kWh)	(6.9)	(7.0)	(7.0)	(7.0)	(12.7)	(12.7)	(12.8)	(13.1)	(13.1)

Table V-1. Capital and O&M Costs for Selected Kenya Geothermal Prospects (continued)

Capital and O&M Costs
for
Selected Kenya Geothermal Prospects

Sheet No. 2 of 2
Job No. 10093
Date 11/27/90

Subject: Detail Summary | By JRB

Prospect:	Chepchok	Loruk	Mwananyamala	Kapedo/Lorusio	Lake Magadi	Homa Mountain
Case Data						
Plant Size, MW	20	10	10	10	10	10
Resource Temp., °C	200	200	165	165	140	180
Well Prod., MW/well	3.0	3.0	3.0	3.0	1.7	3.0
Production Wells	7	4	4	4	6	4
Injection Wells	4	2	2	2	3	2
Spare Wells	1	1	1	1	1	1
Dry Wells	2	2	2	2	2	2
Well Depth, m	1,150	1,150	1,100	1,100	1,000	1,100
Exploration Factor	1.05	1.05	1.05	1.05	0.95	1.05
Remot. & Complex.	1.00	0.95	1.10	1.10	0.95	1.05
Investment						
Exploration	2,394,000	2,394,000	2,394,000	2,394,000	2,166,000	2,394,000
Prod. & Inj. Wells	11,817,500	7,592,875	8,519,500	8,519,500	8,312,500	8,132,250
Gath. & Inj. Syst.	2,694,000	1,555,000	2,151,000	2,151,000	3,982,000	1,753,000
Power Plant	29,579,000	20,542,000	16,319,000	16,319,000	23,091,000	20,878,000
Trans. Line	7,000,000	5,950,000	4,200,000	6,300,000	1,050,000	4,200,000
Access Road	746,000	0	0	0	0	0
Proj. Costs	5,300,000	2,650,000	2,650,000	2,650,000	2,650,000	2,650,000
Total	$59,500,000	$40,700,000	$36,200,000	$38,300,000	$41,300,000	$40,000,000
($/kW)	($2,975/kW)	($4,070/kW)	($3,620/kW)	($3,830/kW)	($4,130/kW)	($4,000/kW)
O&M Costs						
Wells	1,300,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Gath. & Inj. System	127,800	108,400	122,300	122,300	159,700	113,700
Power Plant	602,000	440,000	364,000	364,000	485,000	446,000
Transmission Line	70,000	60,000	42,000	63,000	11,000	42,000
Total	$2,099,800	$1,808,400	$1,728,300	$1,749,300	$1,855,700	$1,801,700
(mills/kWh)	(13.3)	(22.9)	(21.9)	(22.2)	(23.5)	(22.8)

Figure V-1. Capital Cost Analysis, 50 MW Power Plants

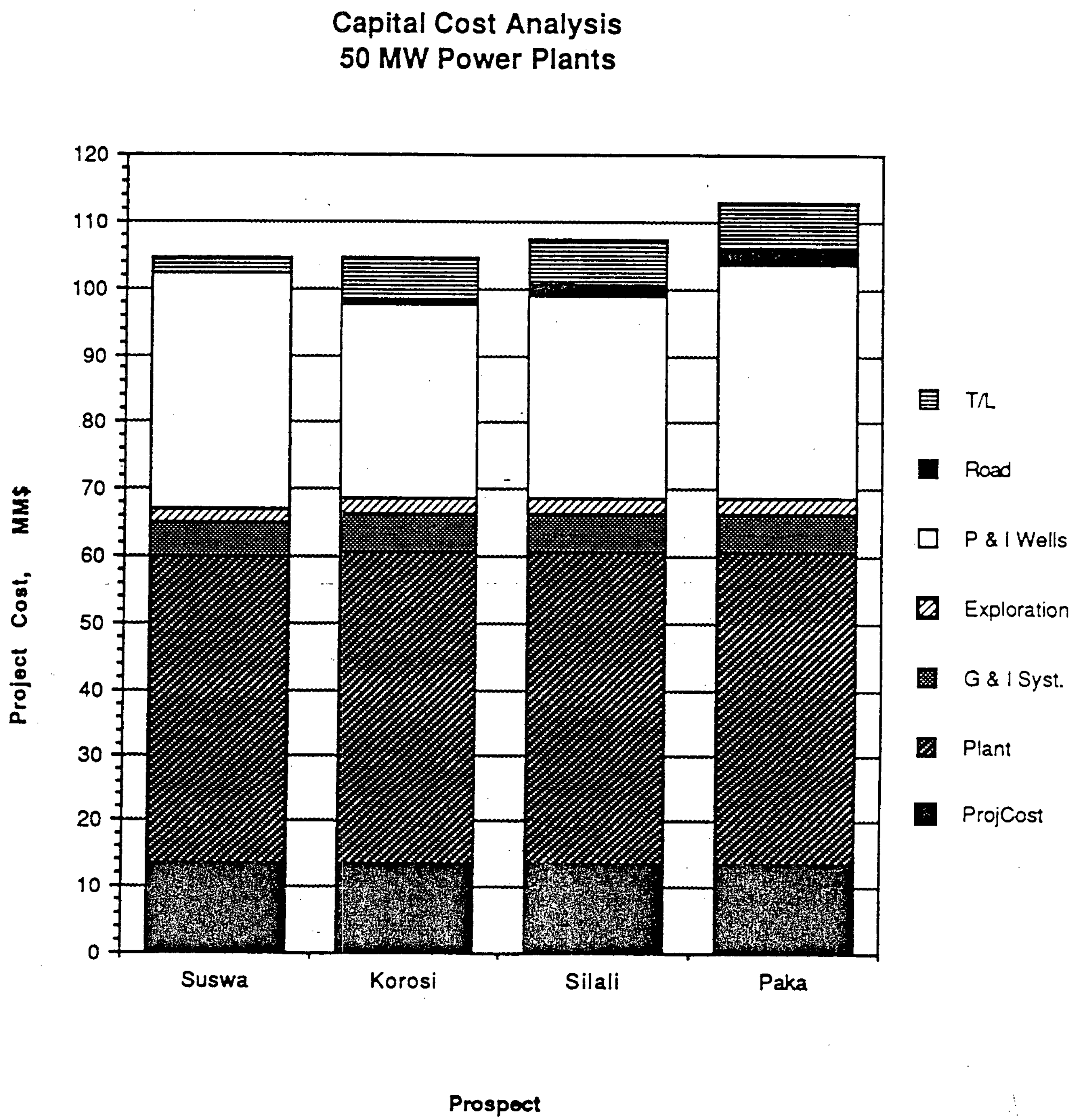


Figure V-2. Capital Cost Analysis, 20 MW Power Plants

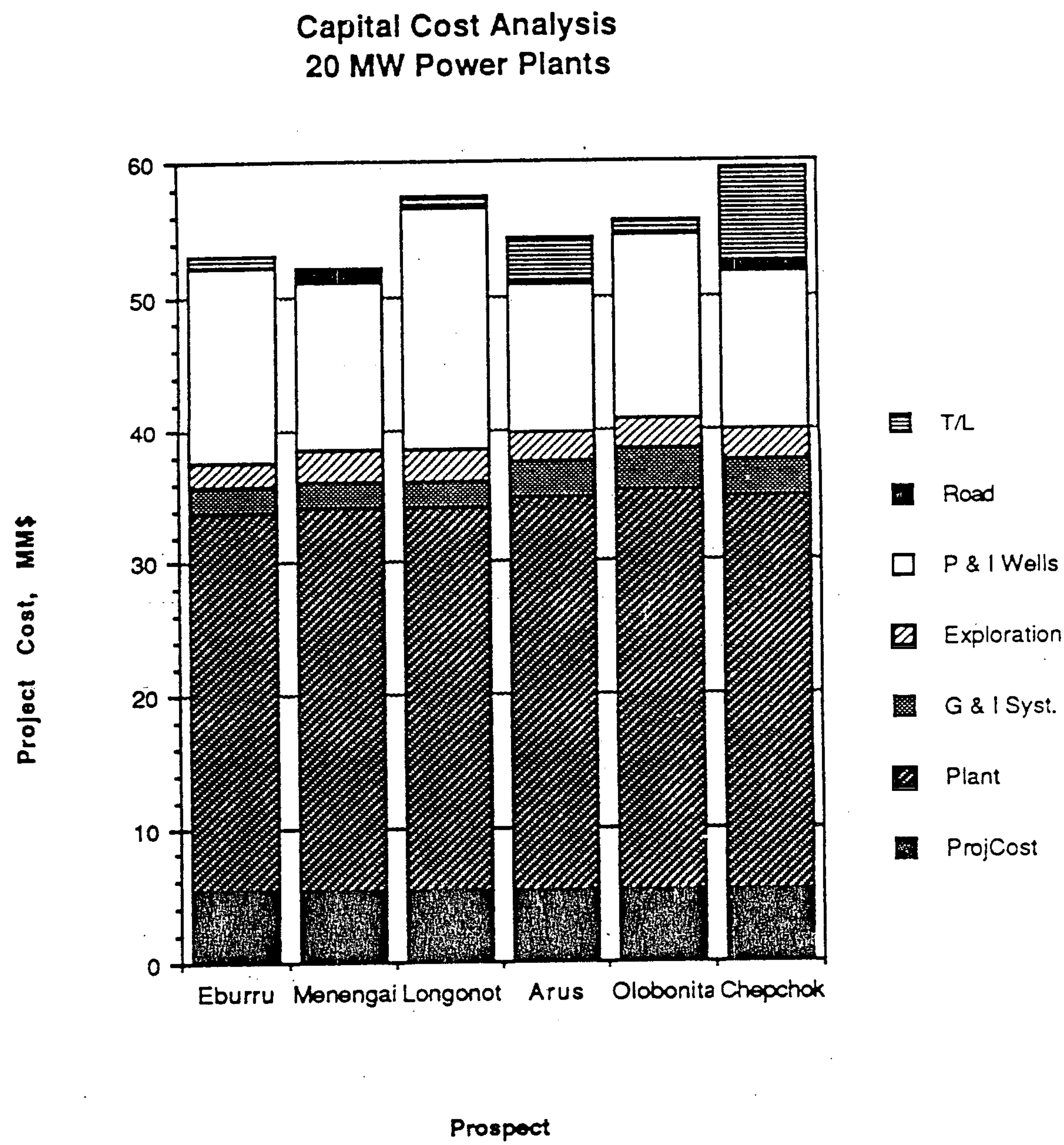


Figure V-3. Capital Cost Analysis, 10 MW Power Plants

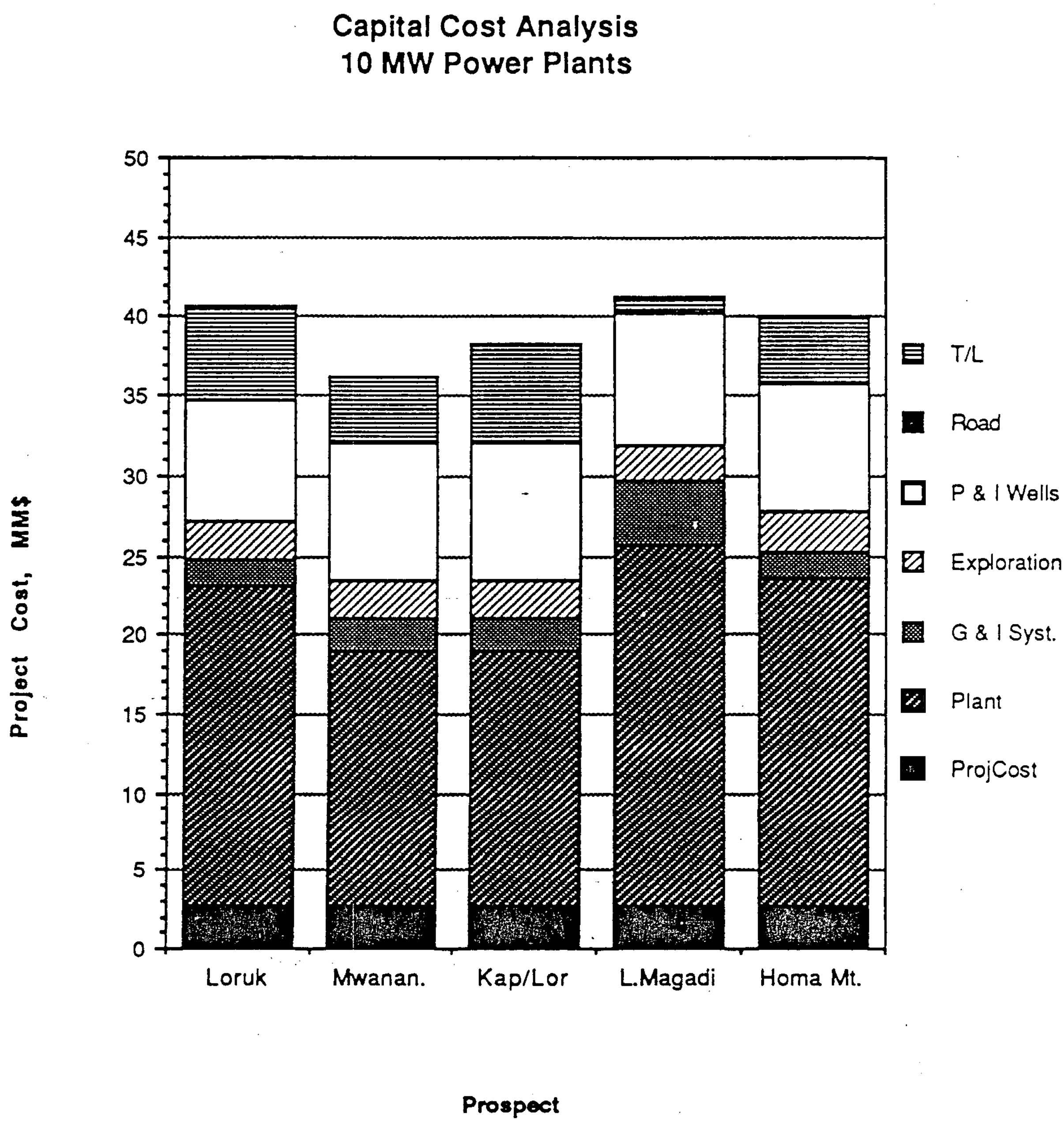
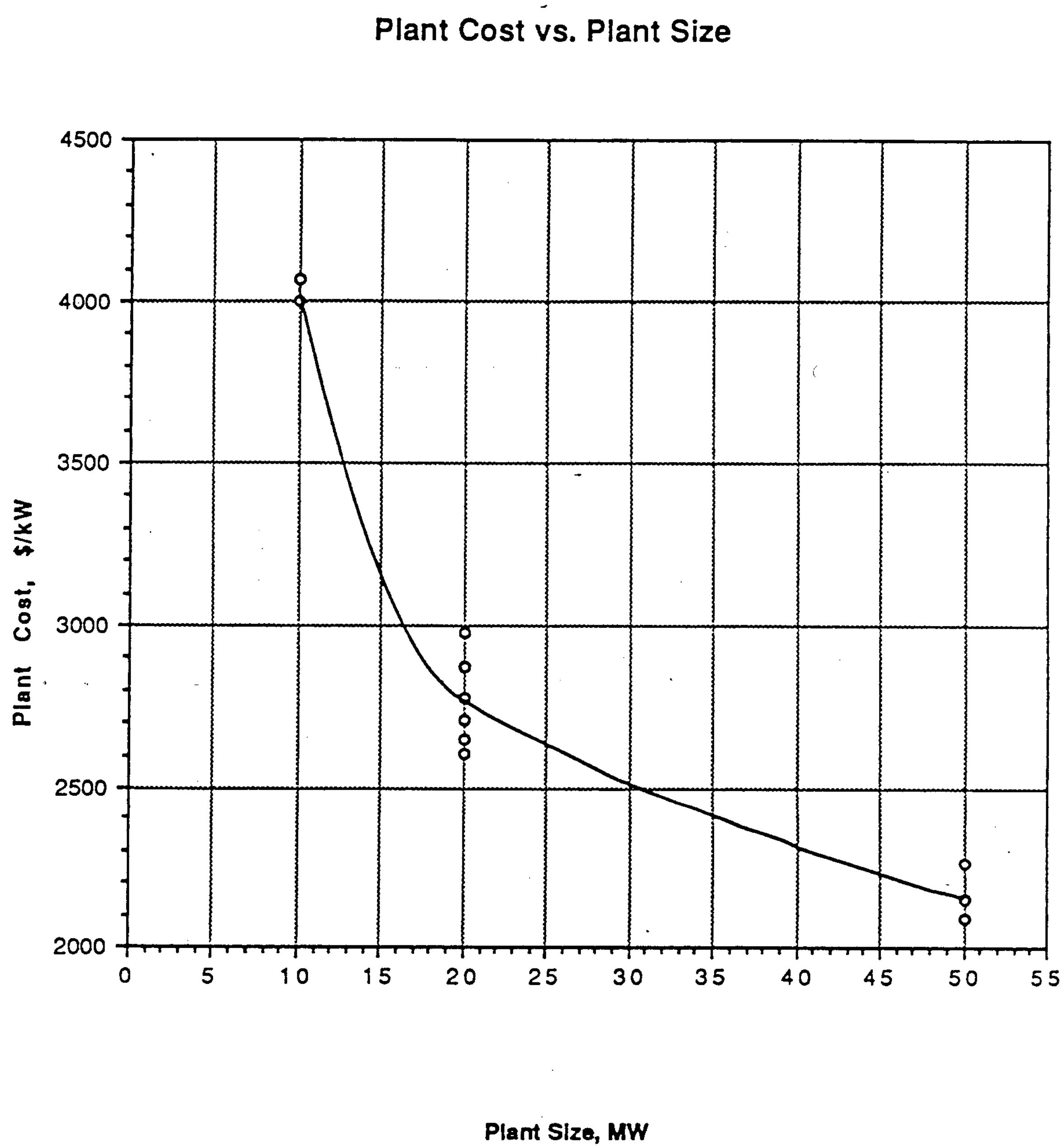


Figure V-4. Plant Cost vs. Plant Size



3. Conceptual Design

a. Dual Flash Steam Cycle

Figure V-5 is a process diagram of the dual flash cycle. Geothermal fluid flows from the production wells to the high pressure separator where the steam and liquid are separated. The H.P.separator is located at the production pad adjacent to the production wells in order to minimize the length of two-phase piping. From there, the steam and brine are conducted to the power plant in separate pipelines. The low pressure separator(s) is located at the plant.

Both high and low pressure steam are fed to the dual pressure turbine which is a single case machine with either single or double flow depending on size. Exhaust steam from the turbine is condensed by cooling water in a direct contact condenser. The condensate plus cooling water is pumped by the hot well pumps back to the cooling tower.

The liquid from the L.P.separator goes first to the injection booster pumps and then by pipeline to the injection pads.

In order to accommodate the wide variety of reservoir conditions occurring at the various prospects included in this study, we have examined a number of cases for different plant sizes and resource temperatures. Figure V-6 is a chart of the 13 power plant cases which were examined.

The maximum H.P.flash pressure allowed was 100 psia. For the lower resource temperatures, lower flash pressures were used as appropriate. The L.P.flash pressure was kept above the ambient pressure of about 11.5 psia.

The turbine exhaust was maintained at 2 "Hga (101 °F). In all cases, the combined turbine-generator efficiency was taken to be 75% which is representative of current state-of-the-art for dual pressure geothermal units.

The cooling tower size was calculated based on a design wet bulb temperature of 57 °F. This was the design temperature for the Olkaria plants. The required size is reported as a "size factor" which compares the subject case with an existing tower now in operation in a dual flash geothermal plant. A size factor of 0.25 means that the required cooling tower is one-fourth the size of the comparison tower. It is assumed that the tower will have the same height and irrigation rate (gpm/ft2) as the comparison tower.

For each case, the various parasitic loads were calculated. These include the pumping loads of the hot well, brine booster and injection pumps, the cooling tower fan load, transformer losses and

Figure V-5. Dual Flash Steam Cycle

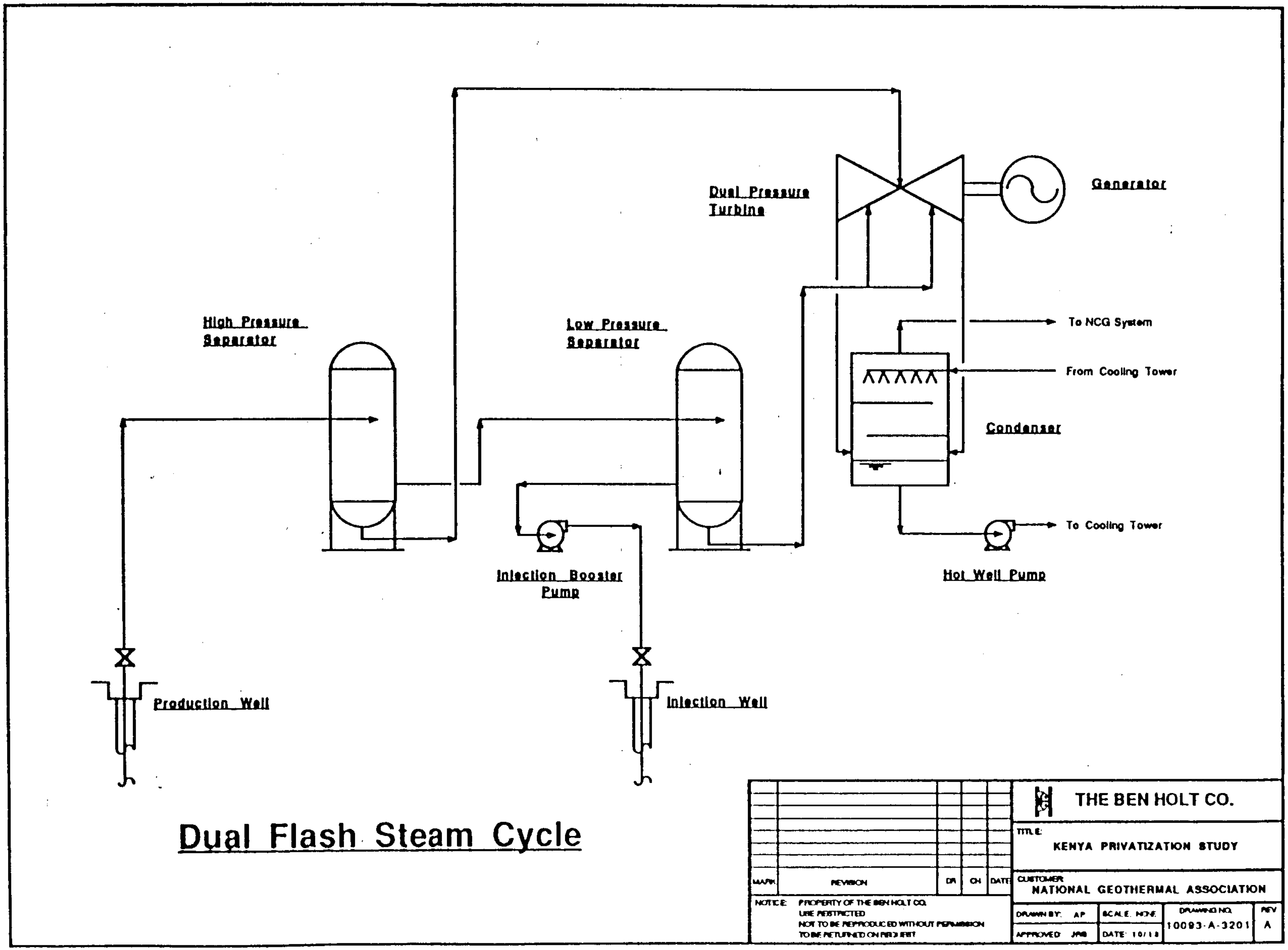


Figure V-6. Dual Flash Steam Cycle Cases

Dual Flash Steam Cycle Cases

Resource Temperature \ Plant Size	10 MW	20 MW	50 MW
300 °C	X	X	X
285 °C	X	X	X
240 °C	X	X	X
200 °C	X	X	
180 °C	X	X	

miscellaneous loads such as lighting, instrument air and HVAC loads.

A typical example of the output of a steam cycle calculation is given in Figure V-7.

b. Binary Cycle

Figure V-8 is a process diagram of the binary cycle. Geothermal fluid is pumped by a line shaft pump from the production well to the power plant. There it passes through the brine/hydrocarbon heat exchanger and to the injection booster pump from which it is pumped to the injection well. The geothermal fluid remains in the liquid phase through the entire cycle.

The hydrocarbon working fluid (in this case isobutane) is pumped through the brine/hydrocarbon exchanger where it is vaporized at high pressure. The vapors are then sent to a radial inflow expander. The exhaust vapor leaves the expander at low pressure and enters the shell-and-tube condenser. Cooling water from the cooling tower is used to return the hydrocarbon vapors to the liquid phase before they pass to the accumulator which feeds the circulating pump completing the cycle. The binary cycle is a completely closed loop for both the geothermal fluid and the working fluid and is particularly suitable in environmentally sensitive areas.

Two binary cycle cases were examined. At each of two resource temperatures, 165 °C and 140 °C, a power plant of 10 MW was evaluated.

The radial inflow expander was selected for this study based on its successful application in several existing plants. An expander efficiency of 79% was used based on the actual performance of existing units. Due to manufacturing limitations, expander size is limited to a maximum of about 5 MW (gross). Therefore, the power plants consist of multiple units. Although there is a reduction in the economy of scale, the plants are more reliable since the loss of any one expander will result in only a partial loss of output from the plant.

The cooling tower for the plant was designed in the same way and with the same assumptions as given above for the steam plant. Binary plants have larger auxiliary loads than steam plants. The largest load is the hydrocarbon circulating pump. The next largest are the well pumps. Other loads include the cooling tower, cooling water pumps, injection booster pumps, transformer losses and miscellaneous loads as described above for the steam plant.

A typical example of the output of a binary cycle calculation is given in Figure V-9.

Figure V-7. Dual Flash Steam Cycle

Sheet No.	1
Job No.	10093
Date	11/29/90
Design	JRB

Subject: Dual Flash Steam Cycle

Suswa (Design)	hb=	578.30 btu/#		(Tbh=	572 °F)
				(Tbh=	300 °C)
	Xhp=	0.3148	Wb=	2,500,319 #/hr	
	Xlp=	0.1196	Wl=	1,704,532 #/hr	
H.P. Flash:	783,285 #/hr	@	328 °F	(	100.00 psia)
	hv=	1187.2 btu/#		sv=	1.6027 btu/#-°R
	hl=	298.51 btu/#		Pipeline ΔP=	10.0 psi
H.P. Steam:	783,285 #/hr	@	320 °F	(	90.00 psia)
	hv=	1185.3 btu/#		sv=	1.6113 btu/#-°R
L.P. Flash:	203,838 #/hr	@	214 °F	(	15.43 psia)
	hv=	1151.4 btu/#		sv=	1.7528 btu/#-°R
	hl=	182.67 btu/#		Pipeline ΔP=	1.0 psi
L.P. Steam:	203,838 #/hr	@	211 °F	(	14.43 psia)
	hv=	1150.1 btu/#		sv=	1.7582 btu/#-°R
Condenser:	P=	2.0 "Hg	T=	101 °F	
	hv=	1105.6 btu/#		sv=	1.9796 btu/#-°R
	hl=	69.14 btu/#		sl=	0.1316 btu/#-°R

Turbine:

H.P. Section:	Xad=	0.8007		
	ΔHad=	286.29 btu/#	=>	60,479 kW (adiabatic)
L.P. Section:	Xad=	0.8802		
	ΔHad=	168.74 btu/#	=>	10,081 kW (adiabatic)
	Eff.=	75.00%	Total=	70,560 kW (adiabatic)
	Total Req.=	70,560 kW (adiabatic)		
	Actual=	52,920 kW (gross)		
	Actual=	50,000 kW (net)		

Parasitic Loads:

Hotwell Pumps	1169 kW
Closed Loop C.W. Pumps	101 kW
Inj. Booster Pumps	372 kW
Brine Booster Pumps	38 kW
Cooling Tower	791 kW
Transformer Losses	265 kW
Misc.	185 kW
Total	2920 kW

NCG Removal:

NCG Content=	0.50%
Wncg=	12,502 #/hr
Ejector Steam=	62,508 #/hr
Atm. Vent=	33,778 #/hr

Brine Injection:

Spent Brine=	1,500,694 #/hr
C.T. Blowdown=	5,485 #/hr
Total=	1,506,179 #/hr

Figure V-7. Dual Flash Steam Cycle (continued)

Sheet No.	2
Job No.	10093
Date	11/29/90
Design	JRB

Subject: Dual Flash Steam Cycle

Cooling Tower:

Altitude = 6,560 ft (2,000 m)
Atm. Pressure = 11.52 psia

Twb =	57.0 °F	Condenser Approach =	3.0 °F
C.T. Approach =	13.0 °F		
C.T. Range =	26.1 °F	Tv =	73.0 °F
		Pv =	0.40 psia
Tc =	70 °F		
Hc =	38.05 btu/#	P1 =	2.23 psia
		P2 =	5.07 psia
Th =	96.14204 °F		
Hh =	64.15 btu/#	y =	0.0792
		Wv =	440 #/hr
Hin =	920.32 MMbtu/hr		
Hout =	62.47 MMbtu/hr		
Δh =	857.84 MMbtu/hr		
ΔH =	26.10 btu/#		
Wc =	32,873 M#/hr		
Wh =	34,825 M#/hr		
KaV/L =	2.42		
L/G =	0.95		
G =	36,631 M#/hr		
G basis =	29,976 M#/hr		
Size Factor =	**1.2220**		
C.T. Makeup =	0 #/hr		
(	0.0 gpm)		

T, °F	hw	ha	1/Δh
70.0		24.52	
72.7	36.52	27.07	0.1058
80.6	44.40	34.61	0.1022
85.5	50.11	39.27	0.0923
93.5	61.04	46.82	0.0703
96.1	65.24	49.37	

T air out = 84.95 °F
Ps = 0.59 psia
y = 0.040479
Wv = 960,362 #/hr
Blowdown = 5,485 #/hr

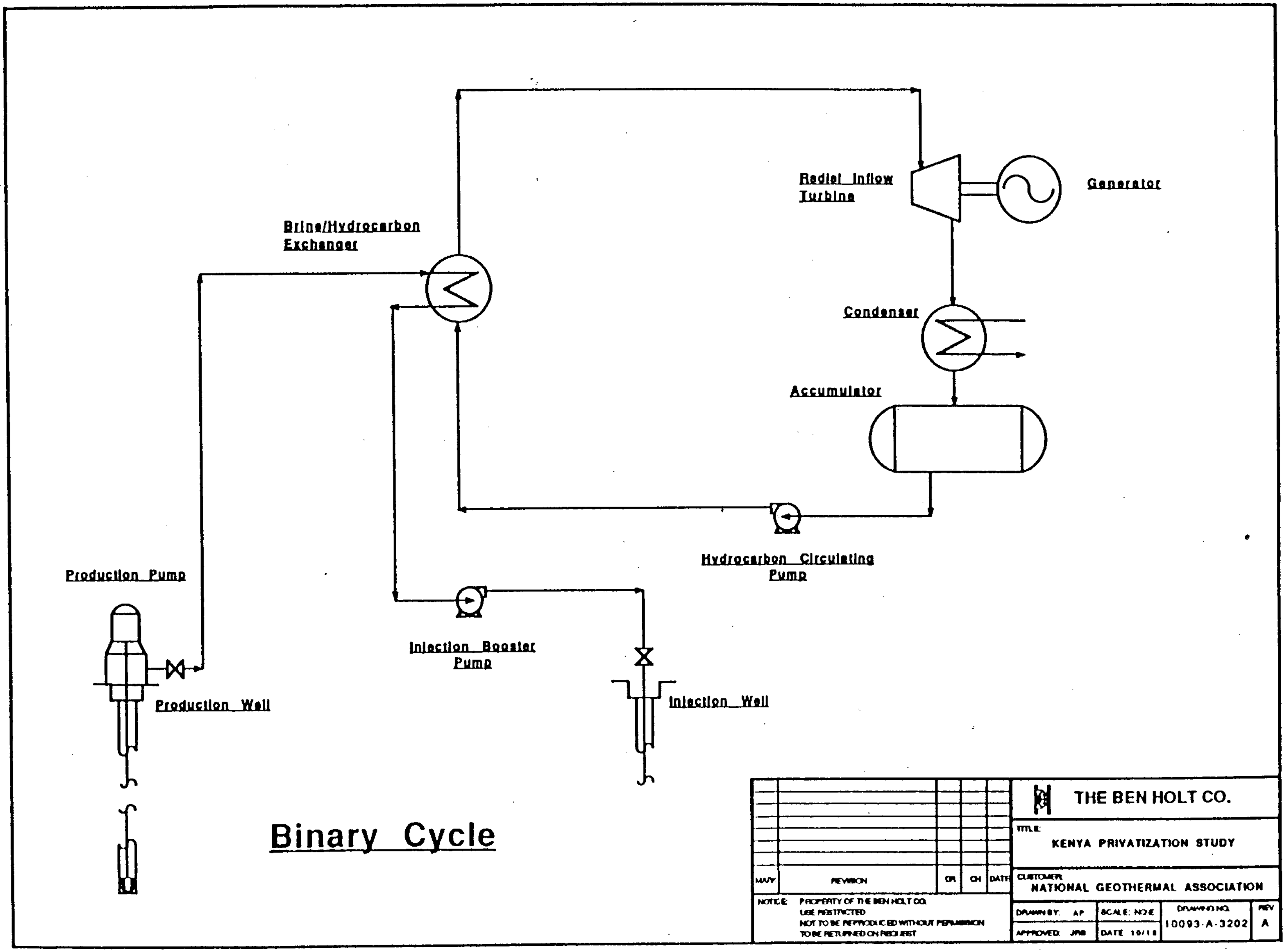


Figure V-8. Binary Cycle

Figure V-9. Binary Cycle

		Sheet No.	1
		Job No.	10093
		Date	10/11/90
Subject:	Binary Cycle	Design	JRB

Mwananyamala	hb-in=	299.75 btu/#	(Tbh=	329 °F)
(Design)			(Tbh=	165 °C)
	hb-out=	146.50 btu/#	(Tbh=	178.5 °F)
			(Tbh=	81.4 °C)
	Δh=	153.255 btu/#		
	Wbr=	**2,326,111 #/hr**	Density =	56.43 #/ft3
			Sp. Gr. =	0.905
	Whc=	1,957,715 #/hr		
Turbine:				
	Δh-gen=	25.3610 btu/#		
	Actual=	14,551 kW (gross)		
	Actual=	10,000 kW (net)		

Parasitic Loads:

C.W. Circ. Pumps	532 kW
H.C. Circ. Pumps	1956 kW
Inj. Booster Pumps	591 kW
Well Pumps	899 kW
Cooling Tower	315 kW
Transformer Losses	73 kW
Misc.	185 kW
Total	4551 kW

Brine Injection:

Spent Brine=	2,326,111 #/hr
C.T. Blowdown=	69,137 #/hr
Total=	2,395,248 #/hr

Well Pumps:

Brine V.P. =	101.65 psia
Lift =	365 ft
TDH =	698 ft

Figure V-9. Binary Cycle (continued)

Sheet No. 2
Job No. 10093
Date 10/11/90
Design JRB

Subject: Binary Cycle

Cooling Tower:

Altitude =	6,560 ft	(2,000 m)	
Atm. Pressure =	11.52 psia		
Twb =	57.0 °F	Condenser Approach =	10.0 °F
C.T. Approach =	13.0 °F		
C.T. Range =	19.7 °F		
Tc =	70 °F	Density =	62.29 #/ft3
Hc =	38.05 btu/#	Sp. Gr. =	0.999
Th =	89.7 °F	Density =	62.11 #/ft3
Hh =	57.71 btu/#	Sp. Gr. =	0.996
Condenser Duty =	159.09 btu/#-hc		
Δh =	311.44 MMbtu/hr		
ΔH =	19.66 btu/#		
Wh =	15,841 M#/hr		
(	31,799 gpm)		
KaV/L =	2.24		
L/G =	1.09		
G =	14,595 M#/hr		
G basis =	29,976 M#/hr		
Size Factor =	**0.4869**		
C.T. Makeup=	414,824 #/hr		
(	830.1 gpm)		

T, °F	hw	ha	1/Δh
70.0		24.52	
72.0	35.92	26.71	0.1086
78.0	41.66	33.20	0.1182
81.7	45.63	37.21	0.1187
87.7	52.90	43.70	0.1086
89.7	55.53	45.89	

T air out =	81.92 °F
Ps =	0.54 psia
y =	0.036714
Wv =	345,687 #/hr
Blowdown =	69,137 #/hr

c. Gathering and Injection System

The gathering system consists of the piping and equipment necessary to transport the geothermal fluid from the production wells to the power plant. The injection system serves the same function between the plant and the injection wells.

For the purposes of this study, it is assumed that each reservoir is capable of supporting a production rate of 5 MW per 40 acres and that the wells are spaced accordingly. Furthermore, it is assumed that the productive region is distributed along a fault system and that, therefore, the production field is long and narrow. The power plant will be sited at the approximate center of the production field in order to minimize the gathering piping. Each production pad will support three producing wells.

The H.P. separators are located at the production pads. The maximum capacity of a H.P.separator is 10 MW. Therefore, for wells of 5 MW/well productivity there will be three separators per pad and for the other cases only one separator which will be shared by all three wells. Both the H.P.steam and the flashed brine will be sent to the plant in insulated pipelines. At the plant, the brine will be flashed again in the L.P.separators. The liquid from this flash will be sent to the injection wells.

It is assumed that there will be one injection well for every two production wells. These will be located in an injection field which will also follow the structure but be displaced laterally from the production field. The displacement ranges from about 1500 feet to 2500 ft depending on the productivity of the production wells.

The steam lines were sized to minimize the pressure drop from the separators to the plant. In general, a maximum pressure drop of 10 psi was allowed. The steam lines are between 10 and 30 inches in diameter. The liquid lines for both the flashed brine and the injected brine were sized for a maximum liquid velocity of 8 fps. They range from 6 to 20 inches in diameter. The insulation thickness was 2.5 inches for gathering lines and 1 inch for the injection lines.

In addition to the pipelines, it was assumed that the well pad access roads as well as the electric power lines and instrument air lines would follow the pipeline routes.

Figure V-10 gives a typical example of the gathering and injection system design for each case. It also includes the cost of the pipelines, roads, etc. The cost of the separators and associated equipment is included elsewhere.

Figure V-10. Gathering & Injection System Design - Suswa 50 MW

Sheet No. 1
Job No. 10093
Date 11/21/90
Design JRB

Subject: Gathering & Injection System Design - Suswa 50 MW

Case	D1d	Plant Size	50 MW
Well Productivity	3 MW/well	Res. Temp.	300 °C
Production Wells	17 wells	Steam Flow	783,285 lb/hr
Injection Wells	8 wells	Brine Flow	1,704,532 lb/hr
Well Pad Separation	1910 ft	Inj. Flow	1,506,179 lb/hr
Unit Length	2390 ft	Allow. ΔP	10 psia
No. of Tiers	3 Production	No. of Tiers	1 Injection

Gathering System

Steam:

Tier	Wells	Branches	Wells/ Branch	Flow lb/hr	Line Length ft	Actual ΔP, psia	Allow. ΔP, psia	Pipe Size, in.	V, fps
0	3	1	3	138,227	625	8.53	10.00	12	207.8
1	6	2	8	368,605	2390	2.71	3.33	30	98.9
2	6	2	5	230,378	2390	3.33	3.33	24	96.2
3	2	1	2	92,151	2390	4.58	3.33	16	87.9
4	0	1	0	0					
					Total ΔP=	10.63	10.00		

Brine:

Tier	Wells	Branches	Wells/ Branch	Flow lb/hr	Line Length ft	Actual ΔP, psia	Allow. ΔP, psia	Pipe Size, in.	V, fps
0	3	1	3	300,800	625	6.30		6	8.0
1	6	2	8	802,133	2390	11.17		10	8.0
2	6	2	5	501,333	2390	14.62		8	8.0
3	2	1	2	200,533	2390	10.84		6	8.0
4	0	1	0	0	-				8.0
					Total ΔP=	36.63			

Tier	Supp't Spc'g ft	Supp't Load lb	Pipeline Cost $/ft	Road, Elect. & Instr. Cost $/ft	Total Cost $
0	20	1,331	131.16	33.45	103,000
1	20	4,481	200.35	33.45	1,118,000
2	20	2,845	173.27	33.45	494,000
3	20	1,723	141.02	33.45	417,000
4					
				Total=	$2,132,000

Injection System

Tier	Wells	Wells per Branch	Wells pe Branch	Brine lb/hr	Line Length ft	ΔP, psia	Pipe Size, in.	Allow. V, fps
0	3	1	3	1,506,179	2390	9.43	14	8.0
1	5	2	3	564,817	2390	17.72	8	8.0
2	0	1	0	0				8.0
3	0	1	0	0				8.0
4	0	1	0	0				8.0
					Total ΔP=	27.16		

Tier	Supp't Spc'g ft	Supp't Load lb	Pipeline Cost $/ft	Road, Elect. & Instr. Cost $/ft	Total Cost $
0	20	2,124	101.99	33.45	324,000
1	20	903	89.10	33.45	586,000
2					
3					
4					
				Total=	$910,000

Grand Total= $3,042,000

4. Capital Cost Estimate

a. Well Costs

For this study, we assumed that the unit drilling costs at each site were equivalent. Therefore, the only variable which affects the well cost is well depth. This was estimated for each prospect by others and reported in Table IV-14 of the Geothermex Report. The well cost is based on an estimated U.S. drilling cost of $650 per meter for exploration wells and $500 per meter for development wells. Well depths vary from 1,000 to 1,750 m with well costs ranging between $500,000 to $1,137,500 per well.

The number of production wells is determined by the plant size and the well productivity. The number of wells per case varies from 4 to 17. The number of injection wells is half the number of production wells.In addition, spare wells are provided and an allowance is made for dry holes.

b. Gathering and Injection System Costs

The cost of the gathering and injection pipelines was given in Figure V-10. The installed cost of the separators and associated equipment was based on the actual cost of similar equipment recently installed in the U.S. For each case, the number and size of separators was calculated. Based on recent experience, the installed cost of the facility was estimated to be about 4.5 times the cost of the major equipment.

c. Power Plant

The capital cost of the power plant was based on the estimated cost of the major equipment. This included the turbine and generator, cooling tower, condenser, hotwell pumps, injection booster pumps, noncondensible gas removal system, L.P.separators, fire protection and other miscellaneous items. For each of the sixteen steam plant cases, the equipment was sized and priced based on equipment costs of recent geothermal construction projects. The same was done for the four binary cycle cases.

The direct construction costs such as concrete, piping, electrical, field supervision, etc., were also based on recent projects. Included were the cost of a construction camp and start-up costs. No sales tax was included and a contractor's profit and contingency of 15% was used. This resulted in the cost to build the plant in the U.S. at a remote location. Figures V-11 and V-12 give examples of the cost estimates for a dual flash steam case and a binary cycle case.

An additional 15% was added to the U.S. price to account for the extra costs associated with overseas construction such as ocean freight and additional home office costs.

Figure V-11. Estimate Summary Sheet, Kenya

ESTIMATE SUMMARY SHEET

CUSTOMER National Geothermal Association

LOCATION Kenya

JOB NO. 10093

PLANT Suswa 50 MW

DATE 11/29/90

ACCOUNT		Materials	Subcontract	Labor	TOTAL
1200	Pressure Vessels	171,900	6,387	2,050	180,337
1300	Heat Exchangers	2,265,500	0	0	2,265,500
1500	Pumps	1,448,100	7,388	8,727	1,464,215
1700	Cooling Towers		2,169,300	0	2,169,300
1800	Compressors	48,000	2,107	1,269	51,376
1900	Tanks	29,000	1,289	311	30,600
2800	Turbine - Generator	9,356,000	0	278,735	9,634,735
2800	NCG Removal Equip.	679,600	0	0	679,600
2800	Gantry Crane		251,000	0	251,000
2800	Diesel Generator	0	0	0	0
2800	Misc.	145,000	122,299	41,710	309,009
TOTAL MAJOR EQUIPMENT		14,143,100	2,559,770	332,803	17,035,673
3100	Concrete	1,038,090	408,968	581,572	2,028,629
3200	Pipe, Valves & Fittings	1,510,074	92,433	192,506	1,795,012
3300	Structural Steel	562,805	0	73,884	636,689
3400	Instruments	496,828	8,508	42,316	547,652
3500	Painting	0	176,207	0	176,207
3600	Electrical	1,478,935	449,886	0	1,928,821
3700	Insulation	0	241,561	0	241,561
3800	Paving, Roads, Fences	28,943	8,055	15,861	52,859
3900	Buildings	0	582,993	0	582,993
4200	U/G Pipe, Valves & Fittings	139,192	0	10,150	149,342
TOTAL CONSTR. ITEMS		5,254,867	1,968,611	916,287	8,139,766
Other Field Costs (p. 2)		2,212,480	890,520	362,824	3,465,824
Indirect Field Costs (p. 2)		280,893	2,336,504	1,022,006	3,639,404
TOTAL FIELD COSTS		21,891,340	7,755,405	2,633,921	32,280,666
8200	Home Office Services				3,005,587
SUB-TOTAL					35,286,253
9500	Sales Tax on Material	0.00%			0
	Fee & Contingency	15.00%			5,292,938
TOTAL SELLING PRICE					$40,579,191

Page 1 of 2

Figure V-11. Estimate Summary Sheet, Kenya (continued)

SUMMARY - FIELD COSTS

CUSTOMER National Geothermal Association			JOB NO. 10093	
LOCATION Kenya			PLANT Suswa 50 MW	
			DATE 11/29/90	
ACCOUNT	Materials	Subcontract	Labor	TOTAL
6000 Ocean/Air Freight	0	0	0	0
6100 Spare Parts	2,132,532	0	0	2,132,532
6200 Catalyst & Chemicals	0	0	0	0
6300 Site Preparation & Grading	0	0	0	0
6400 Dismantling & Demolition	0	0	0	0
6600 Geotechnical Reports	0	0	0	0
7100 Temporary Construction	74,410	250,093	63,745	388,247
7200 Offsite Storage	0	0	0	0
7300 Unallocable Labor - Craft	3,021	0	93,964	96,984
7600 Supervision - Craft	0	0	110,739	110,739
8300 Equipment Rentals	2,517	640,427	94,377	737,321
TOTAL OTHER FIELD COSTS	$2,212,480	$890,520	$362,824	$3,465,824
7400 Start-up Services	0	1,059,759	0	1,059,759
7500 Union Welfare Benefits	0	0	0	0
8100 Field Staff & Office	0	55,379	684,086	739,465
8400 Small Tools	75,160	0	0	75,160
8500 Consumable Supplies	205,733	0	0	205,733
8600 Subsistence & Lodgings	0	1,221,366	0	1,221,366
8700 Field Transportation	0	0	0	0
9200 Permits, Fees & Licenses	0	0	0	0
9300 Insurance, Payroll Taxes	0	0	337,921	337,921
9400 Royalties	0	0	0	0
9700 Duties, Customs, Etc.	0	0	0	0
9900 Outside Engineering	0	0	0	0
TOTAL INDIRECT FIELD COSTS	$280,893	$2,336,504	$1,022,006	$3,639,404

Page 2 of 2

Figure V-12. Estimate Summary Sheet, Mwananyamala, Kenya

ESTIMATE SUMMARY SHEET

CUSTOMER National Geothermal Association			JOB NO. 10093	
LOCATION Mwananyamala, Kenya			PLANT 10 MW Binary Cycle	
			DATE 10/21/90	

ACCOUNT	Materials	Subcontract	Labor	TOTAL
1200 Pressure Vessels	106,400		4,345	110,745
1300 Heat Exchangers	1,568,400		33,647	1,602,047
1500 Pumps	240,400		3,663	244,063
1700 Cooling Towers		864,400	0	864,400
1800 Compressors	182,100		2,850	184,950
1900 Tanks	93,900		4,376	98,276
2800 Turbine - Generator	2,678,300	34,662	13,698	2,726,660
2800 Exhaust Silencer	49,500		1,900	51,400
TOTAL MAJOR EQUIPMENT	4,919,000	899,062	64,478	5,882,540
3100 Concrete	298,704		219,623	518,327
3200 Pipe, Valves & Fittings	701,142	-	260,953	962,095
3300 Structural Steel	87,687	27,513	40,017	155,217
3400 Instruments	325,348		36,222	361,569
3500 Painting		53,251		53,251
3600 Electrical	671,453	17,750	157,672	846,875
3700 Insulation		66,245		66,245
3800 Paving, Roads, Fences	2,840	97,272	13,739	113,851
3900 Buildings		136,856		136,856
TOTAL CONSTR. ITEMS	2,087,174	398,888	728,224	3,214,286
Other Field Costs (p. 2)	31,773	305,769	88,415	425,957
Indirect Field Costs (p. 2)	140,195	0	1,069,826	1,210,021
TOTAL FIELD COSTS	7,178,143	1,603,719	1,950,943	10,732,804
8200 Home Office Services				1,605,349
SUB-TOTAL				12,338,154
9500 Sales Tax on Material	0.00%			0
Fee & Contingency	15.00%			1,850,723
TOTAL SELLING PRICE				$14,188,877

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Figure V-12. Estimate Summary Sheet, Mwananyamala, Kenya (continued)

SUMMARY - FIELD COSTS

CUSTOMER National Geothermal Association			JOB NO. 10093	
LOCATION Mwananyamala, Kenya			PLANT 10 MW Binary Cycle	
			DATE 10/21/90	
ACCOUNT	Materials	Subcontract	Labor	TOTAL
6000 Ocean/Air Freight				0
6100 Spare Parts				0
6200 Catalyst & Chemicals				0
6300 Site Preparation & Grading		97,272		97,272
6400 Dismantling & Demolition				0
6600 Geotechnical Reports				0
7100 Temporary Construction	20,768	45,796		66,564
7200 Offsite Storage				0
7300 Unallocable Labor - Craft	2,130		31,933	34,063
7600 Supervision - Craft				0
8300 Equipment Rentals	8,875	162,700	56,482	228,058
TOTAL OTHER FIELD COSTS	$31,773	$305,769	$88,415	$425,957
7400 Start-up Services				0
7500 Union Welfare Benefits				0
8100 Field Staff & Office			396,722	396,722
8400 Small Tools	52,573			52,573
8500 Consumable Supplies	87,622			87,622
8600 Subsistence & Lodgings				0
8700 Field Transportation				0
9200 Permits, Fees & Licenses			40,116	40,116
9300 Insurance, Payroll Taxes			499,859	499,859
9400 Royalties				0
9700 Duties, Customs, Etc.				0
9900 Outside Engineering			133,128	133,128
TOTAL INDIRECT FIELD COSTS	$140,195	$0	$1,069,826	$1,210,021

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d. Transmission Line

The transmission line from the plant to the transmission grid operates at 232 kV. It is a cross country line supported by wooden H-frames. It is assumed that the transmission line corridor can take the most direct route between the power plant site and the closest approach of the nearest transmission line.

Based on U.S. costs, the transmission line is estimated to cost about $70,000 per kilometer.

e. Access Road

For sites not currently served by an access road suitable for heavy equipment and construction traffic, the cost of an access road was included in the project capital cost estimate. The road is a heavy duty graded gravel road twenty feet wide. It includes drainage and culverts. No provision has been made for bridges, tunnels or extraordinary excavation or blasting.

The cost of this road is estimated to be about $125,000 per kilometer.

f. Project Costs

We have also estimated the amount of various intangible project costs. We have included $65 per kW for siting and licensing as well as $100 per kW each for financing costs and owner's costs during construction.

5. O & M Cost Estimate

a. Well Costs

The two main areas of operating and maintenance costs associated with the production and injection wells are well replacements and rework. It is assumed that over the life of the project, additional production and injection wells will be required either to replace damaged wells or to compensate for declining productivity.

In addition to well replacement, each well will require periodic, rework, cleaning, logging, etc. An amount of $100,000 per year is provided for each well for this purpose. Overhead, warehousing and miscellaneous expenses add another $550,000 per year. The total wellfield O&M cost varies between $1,200,000 and $1,600,000 depending on project size.

b. Gathering and Injection System

There will be three operators required for the gathering and injection system for a total of 12 hires. Based on a local labor rate of 8,000 KS/mo., the annual cost is $70,000 including overhead and benefits.

Maintenance costs include labor, materials and consumable supplies. The annual cost of labor and materials is equal to 1.6% of the facility capital cost. In addition, 0.2% is provided for supplies.

c. Power Plant

There will be three operating positions required for the power plant for a total of twelve hires. As stated above, the annual cost will be $70,000.

Annual maintenance costs are 1.6% of capital investment for labor and materials and 0.2% for supplies.

d. Transmission Line

The allowance for the annual cost of O&M for the transmission line is 1.0% of the installed cost.

6. Project Cost Summary

For each case, a project cost summary was prepared. Figure V-13 is an example of the summary. Each summary contains the details of the capital and O&M cost estimates including the calculation of well, transmission line, access road and project capital costs and the calculation of the O&M costs.

Figure V-13. Geothermal Project Cost Summary, Kenya

GEOTHERMAL PROJECT COST SUMMARY

CUSTOMER	National Geothermal Association	Job No.	10093
PLANT	Private Power Project	Date	11/27/90
LOCATION	Kenya	Page	1 of 2

CASE: Suswa

Project Life	25 years
Plant Size	50 MW
Resource Temp.	300 °C
Well Productivity	3.0 MW/well

COST RECAP

	Investment	Annual O&M Cost
Exploration	2,052,000	
Prod. & Inj. Wells	34,980,750	1,600,000
Gathering & Inj. System	5,197,000	171,000
Power Plant	46,666,000	910,000
Transmission Line	2,450,000	25,000
Site Access Road	0	
Project Costs	13,250,000	
Total	$104,600,000 ($2,092/kW)	$2,706,000 (6.9 mills/kWh)

EXPLORATION COSTS

Base Exploration Cost	$2,280,000
Exploration Factor	0.90
Exploration Cost	$2,052,000

WELL COSTS

Well Depth	1700 m	5,600 ft	
Incr. Well Cost:			
First 3 wells	$650 / m	$198 / ft	$1,105,000/well
Remaining wells	$500 / m	$152 / ft	$850,000/well
Number of Wells	17 Prod. 2 Spare	9 Inj. 4 Dry	
Drilling Cost	$27,965,000		
Non-drilling Cost	$5,350,000		
Total Wellfield Cost	$34,980,750	(Remote & Compl. = 1.05)	
Total O&M Cost	$1,600,000		

Figure V-13. Geothermal Project Cost Summary, Kenya (continued)

CUSTOMER	National Geothermal Association		Job No.	10093
PLANT	Private Power Project		Date	11/27/90
LOCATION	Kenya		Page	2 of 2

CASE: **Suswa**

			Initial Cost		Annual Increase
GATHERING & INJECTION SYSTEM COSTS					
	Investment Cost		$5,197,000		$8,000
	Operating Labor				
		No. of Positions	3		
		Labor Rate	8,000 KS/mo.		
		Annual Cost	$70,000		
	Maintenance				
		Labor & Mat'l	$83,000	(1.6%)	$130
		Supplies	$10,000	(0.2%)	$20
	Annual O&M Cost		$171,000		$150
POWER PLANT COSTS					
	Investment Cost		$46,666,000		
	Operating Labor				
		No. of Positions	3		
		Labor Rate	8,000 KS/mo.		
		Annual Cost	$70,000		
	Maintenance				
		Labor & Mat'l	$747,000	(1.6%)	
		Supplies	$93,000	(0.2%)	
	Annual O&M Cost		$910,000		

TRANSMISSION LINE COSTS				
	T/L Length	35 km		
	Unit Cost	$70,000 $/km	$112,700 $/mi.	
	Total Investment	$2,450,000		
	Annual O&M	$25,000 (1.0%)		
SITE ACCESS ROAD COSTS				
	Road Length	0 km		
	Unit Cost	$124,300 $/km	$200,000 $/mi.	
	Total Investment	$0		
PROJECT COSTS				
	Siting & Licensing	3,250,000	($65 /kW)	
	Financing Costs	5,000,000	($100 /kW)	
	Owner's Costs	5,000,000	($100 /kW)	
	Total Project Costs	$13,250,000		

Section VI. PRIVATE POWER OPTIONS AND POTENTIAL: EXPERIENCE IN OTHER COUNTRIES

A. INTRODUCTION

Several developing countries with shortages of electric power have enacted or are considering enacting legislation permitting private financing, ownership and operation of discreet electric power generating facilities. These countries, which include the Philippines, the Dominican Republic, Pakistan, and India, are seeking to supplement the publicly financed expansion of their electric power systems through private participation. By doing so, they hope to attract new sources of capital that are not traditionally available to the power sector, and increase the efficiency of the sector by introducing competition.

Each country has followed a different although somewhat similar, legal and institutional approach to inviting private sector participation. Generally, the first step is to enact an enabling law or executive decree permitting private entry into the power sector. This either includes, or is followed by, a detailed set of implementation regulations that defines the institutional and procedural framework for soliciting, evaluating and implementing private power projects. In some countries the implementation regulations cite any incentives that the government is willing to provide to prospective project developers. In others, incentives are determined during negotiation of the power purchase and implementation agreements. Purchase prices for electric power generated by the private sector are then established, and power purchase agreements are developed.

The purpose of this section is to briefly review the approach to private power taken by the Philippines, Pakistan, and the Dominican Republic. This section is not intended to provide a detailed analysis of the institutional, legal and financial structure that has been established to promote private power in each of these countries. Rather, it is intended to provide an overview of the approaches taken by each country.

1. Phillipines

a. Electric Power System Overview

The National Power Corporation, the government-owned national utility, has an installed generating capacity of 5,788 MWs. The generating system is composed of 2,124 MWs of hydroelectric capacity, 894 MWs of geothermal capacity, 2,239 MWs of oil-fired steam turbine capacity, 126 MWs of diesel capacity, and 405 MWs of coal-fired capacity.

During the ten year period 1989-1999, according to the World Bank, the Philippines will add 3,679 MWs of new capacity. The corresponding investment requirement for the new capacity, and transmission and distribution capacity additions is estimated to be $7.5 billion. The World Bank estimates that only 28 percent of this investment requirement will be sourced domestically.

Although growth in demand for electricity has fallen from 9.4 percent in 1987 to 7.9 percent in 1989, demand is still outpacing the ability of NPC to construct new power plants. Moreover, recent droughts have reduced the reserve margin of the hydroelectric dependent utility. This situation has been compounded by frequent outages of thermal power plants. The result has been severe power shortages and increasingly frequent blackouts in Luzon.

Anecdotal evidence suggests the cost of scheduled and unscheduled load shedding in the Philippines is high. Under a system devised in 1982, over 1,500 industrial plants, representing nearly 75 percent of Manila's industrial output shut down once a week to conserve energy. In early 1990, 365 of the largest commercial buildings in Manila temporarily established four day work weeks in hopes of receiving uninterrupted power during operating hours. Industry in the Philippines is estimated to lose $1.1 million dollars daily due to a lack of reliable electric power.

b. Private Power Legislation

Concerned with the negative economic effects of the power shortages, the Government of Corazon Aquino enacted Executive Order No. 215 in 1987 to allow the private sector to invest in electric power generating facilities. Among the provisions of its preamble, E.O. No. 215 recognizes that electric power generation is not a national monopoly, and further recognizes private participation in the energy sector as a means of increasing the nation's generating capacity without requiring financial assistance or guarantees from the government.

The Executive Order establishes the types of energy facilities that the private sector may own and operate. These include cogeneration units, electric generating plants intending to sell all or part of its production to the national grid, and plants located outside the national grid system that may sell power directly to end users.

Most importantly, to simplify and expedite the process of private power project development, the Executive Order required the National Power Corporation to develop a set of standard rules and regulations that define the responsibilities of the National Power Corporation and the project developer in all stages of project development. These regulations were made a condition precedent for enacting in full, the Executive Order.

c. Private Power Regulations

The implementation regulations establish qualifying criteria for three categories of privately owned power facilities. These categories include: mini-Private Sector Generating Facilities -- facilities under 1000 kW (later expended to 5 MW); Private Sector Generating Facilities -- those facilities over 1000 kW, but less than the largest NPC unit on the grid; and Block Power Production Facilities -- facilities included on the NPC expansion plan, but that are developed and owned by the private sector.

Proposals for Mini-Private Sector Generating Facilities are submitted to the National Power Corporation on an unsolicited basis, but must receive accreditation from the National Power Corporation to certify that they meet the economic, ownership and engineering criteria established in the regulations. Mini-PSGF of less than 5 MW may sell power to the National Power Corporation at various published rates depending on whether they offer firm capacity, are dispatchable, or offer "take or pay" arrangements. These rates are periodically published in national newspapers of the Philippines.

Proposals for PSGF, like mini-PSGF, are generally unsolicited, and must also receive accreditation from the National Power Corporation. Upon accreditation, under the regulations, the National Power Corporation is obligated to interconnect with the facility and purchase power at the utility's avoided cost of generation. The methodology for calculating the avoided cost, and the avoided cost itself, is filed with the Office of Energy Affairs, which serves to resolve disputes throughout the development and operation phases of a private project.

Proposals for Block Power Production Facilities may be unsolicited, or may be submitted in response to a formal solicitation issued by the National Power Corporation. Like Mini-PSGF and PSGF, Block Power Production Facilities must also receive accreditation from the National Power Corporation. Power Purchase rates for Block Power Corporation Facilities are negotiated on a case-by-case basis.

d. Private Power Projects

In August, 1990, a 200 MW gas turbine private power project began operation. The 200 MW gas turbine project, was developed by Hopewell Project Management Company, Ltd., of Hong Kong, using the Build-Operate-Transfer (BOT) development scheme. Under the BOT arrangement, Hopewell will own and operate the project for a period of 12 years, at the end of which time it will transfer ownership to the National Power Corporation. Revenue from the project originates from a two-part tariff, consisting of a capacity fee and a separate fee for energy delivered from the plant.

The project was financed with equity from Hopewell, Citicorp, the Asian Development Bank (ADB) and the International Finance Corporation (IFC). Debt financing was provided by the ADB, the IFC, and a syndicate of commercial banks.

In August, 1990, NPC also awarded a consortium of Hopewell Holdings Limited and Asea Brown Boveri the right to develop a 700 MW coal-fired Build-Operate-Transfer power plant in San Juan Batangas on Luzon island. NPC issued a request for proposals for the coal-fired project in November, 1989, and had prequalified fourteen firms for bidding. The plant is scheduled for completion in July, 1993, and will be the second private power plant completed under E.O. 215.

e. Private Power Investment Incentives

The Government of the Philippines provided Hopewell Holdings, Ltd. with a number of investment incentives for the 200 MW gas turbine project. Under the Philippines investment codes, the Hopewell project was certified a "pioneer" industry, which allows for 100% foreign ownership. The project was exempted from all revenue taxes for a period of six years, and was exempted from all import duties on capital equipment. Hopewell also received a 100% tax credit for locally supplied capital equipment, and a 100% tax exemption from the value added tax for local contractors associated with the project. The government also provided Hopewell with a vacant site for the project complete with access roads, water and telephone lines, and a transmission line to the nearest switching station.

Most importantly, the Government of the Philippines guaranteed the performance of the utility under the contract. Under the agreement, the government agrees to pay Hopewell, in the currency stated in the contract, any sum that the National Power Corporation is late in remitting. This allowed the lenders to provide debt financing for the project without requiring a sovereign guarantee from the government.

2. Pakistan

a. Electric Power System Overview

The Water and Power Development Authority (WAPDA), the government-owned national utility, has an installed capacity of 5,115 MWs. The entire electric generating system of Pakistan, including self production by the private sector, consists of 70MWs of nuclear capacity, 2,893 MWs of hydroelectric capacity, 1,703 MWs of oil-fired steam capacity, 847 MWs of diesel capacity, 500 MWs of gas-fired steam capacity, 865 MWs of combustion turbines, 600 MWs of combined cycle capacity and 12 MWs of coal-fired capacity.

During the ten year period 1989-1999, according to the World Bank, the Government of Pakistan will require an additional 12,873 MWs of additional generating capacity. The corresponding investment requirement for new generation, transmission and distribution capacity is estimated to be $18 billion. Approximately 46 percent is expected to be sourced domestically.

Demand for electric power has been rising at an annual rate of 11 percent since the early 1980s. The Water and Power Development Authority (WAPDA), has had difficulty in keeping pace with the rapidly rising demand. The result had been the load shedding, once a seasonal phenomena, has become a year-round occurrence.

A study prepared for WAPDA and the U.S. Agency for International Development indicates that during the 1980s, load shedding in the industrial sector of Pakistan resulted in an annual reduction of the value added of that sector of 8.2%. The total direct and indirect costs of load shedding to the national economy represent a 1.8% reduction in gross domestic product.

b. Private Power Legislation

Recognizing that private investment can supplement the traditional, government-financed expansion of the power sector, the Government of Pakistan was the first country to promote private power. Although it has not passed a formal law permitting private power, the Government of Pakistan has issued several policy pronouncements endorsing private power projects as a means of increasing the generating capacity of the country. In its seventh five year economic development plan (1988-1993), the Government of Pakistan state that the private sector would contribute 2,000 of the 6,000 MWs called for in the electric power expansion plan.

A further indication of the commitment of the government to private power is the establishment of the Private Sector Energy Development Fund with assistance from the World Bank, the U.S. Agency for International Development and other bilateral donors including Japan, the United Kingdom, German, Canada and Italy. The Fund is designed to encourage private energy projects by lending up to 30 percent of the total project cost, which may include 50 percent of the foreign exchange costs. Loans may have a maturity of up to 23 years, with an eight year grace period. The current interest rate for loans from the fund is 14 percent.

c. Private Power Regulation

The Government of Pakistan has designated a regulatory and institutional framework for private power. This framework, while not a formal regulatory statute, outlines the institutions responsible for the oversight of private power projects, and explains the procedures for submitting private power project proposals to the Government.

To facilitate private power development a Private Power Cell was established in the Ministry of Water and Power to evaluate proposals for, and conclude agreements on, private power projects. A separate Private Power Cell was established in WAPDA to negotiate and enforce power purchase agreements.

Under the regulations, project companies must be incorporated in Pakistan. Twenty-five percent of the project capital must be in the form of equity. There is no limit to the amount of equity held by foreign entities.

Project developers may submit proposals to the PPC of the Ministry of Water and Power either in response to a request for proposals or on an unsolicited basis. Proposals submitted in response of a request for proposals are evaluated according to the following criteria:

* Qualifications of the project sponsors, contractors, and equipment suppliers;
* Ability of the proposed project to meet the required technical standards;
* Ability of the proposed project to meet the environmental guidelines and the occupational safety and health guidelines of the Government of Pakistan;
* Ability of the project to attract full financing; and
* Cost estimates presented as a basis for the sale of electricity are soundly based and reasonable compared with the costs that would be incurred if WAPDA were to undertake the project.

The winning proposals is issued in a letter of intent by the Ministry. The developer finalizes the proposal by preparing an implementation plan for the project, completing the environmental assessments, and closing any price reopener that were in the original proposal. The final step is to negotiate and sign a power purchase contract with the Private Power Cell of WAPDA and an implementation agreement with the Ministry of Water and Power.

Unsolicited proposals are submitted to the PPC of the Ministry of Water and Power, where they are evaluated to determine if they:

* Are consistent with government policy;
* Form part of the least cost expansion plan of the utility;
* Do not conflict with government plans for solicited proposals.

If approved, the government issues a letter of interest to the developer, which permits him to undertake a feasibility study for the project. The feasibility study is submitted to the PPC of the

Ministry, which evaluates the project using criteria similar to those used in the evaluation of solicited projects. If approved, the project is issued a letter of intent, enabling the developer to finalize the proposal and enter into contract negotiations.

d. Private Power Incentives

1. Enhancement of Security Package

Private power projects in Pakistan, as elsewhere, are financed on a limited recourse basis and, therefore, require a set of interlocking agreements to give security to lenders. To provide greater security to the lenders, the Government of Pakistan is prepared to enhance the security package by assuming certain risks. The security enhancement package offered by the Government, and subject to negotiation on a case-by-case basis includes:

* Protection against specific force majeure risks;
* Protection against changes in taxes and duties;
* Indexation of the power purchase price to protect the project from inflation and changes in the exchange rate; and
* Guarantee of convertibility of Rupees and remittance of foreign exchange to cover imports, debt service, dividends, and capital repatriation.

Most importantly, the Government guarantees the performance of WAPDA under the power purchase contract. If WAPDA fails to take the amount of power contracted for, the government will compensate the project company for the difference in the amount of power taken by WAPDA and the amount called for in the power purchase contract.

2. Fiscal Incentives

The Government of Pakistan provides the following fiscal incentives to project developers:

* Exemption from corporate income tax;
* Exemption of partial exemption from custom duties and sales tax on imports and machinery; and
* Makes available preferential loans for the purchase of locally manufactured machinery.

The project development company may also make use of the Private Sector Energy Development Fund.

3. Dominican Republic

a. Electric Power System Overview

The Corporation Dominica de Electricidad (CDE) is the government-owned utility, and has the obligation to provide the citizens, industry and commercial operations in the Dominican Republic with electric power. The CDE system has an installed generating capacity of 822 MWs. The entire generating capacity of the country, including self production by the private sector, consists of 205 MWs of hydroelectric capacity, 552 MWs of oil-fired steam turbine capacity, 14 MW of diesel capacity and 219 MWs of coal-fired capacity.

The country is currently suffering from a prolonged period of crisis in the electric power subsector. Much of the installed capacity is unavailable due to poor maintenance of the thermal plants. The transmission and distribution system is deteriorating, 30 percent system losses as a result. Blackouts occur from eight to twelve hours daily in some regions of the country.

The national utility currently accounts for approximately two-thirds of the national debt. According to the World Bank, CDE will require $1.5 billion during the period 1989-1999 for power generation expansion. An additional $500 million will be required for transmission and distribution expansion. Of this $2 billion, only 15 percent is expected to come from domestic sources. Private power is seen as a means of attracting new sources of capital to the power subsector.

b. Private Power Legislation

In 1988, President Balaguer issued an emergency decree calling for proposals for private power projects in the Dominican Republic. This followed in 1990 by formal passage of Law 14-90, which permits and encourages private investment in power generation facilities in the Dominican Republic. The purpose of the law is to promote and stimulate new electric power companies, both national and foreign, that contribute to the economic development of the country.

In its preamble, Law 14-90 states that electric energy is essential to the socioeconomic development of the nation. The preamble also states that the development of the electric power subsector will require substantial capital investments, and that the Government of the Dominican Republic is obligated to distribute its limited capital resources equitably among the many sectors of the economy that promote social and economic development. Therefore, to supplement it is inviting private investment to develop the electric power subsector.

c. Private Power Regulation

Law 14-90 creates a Directorate for the Development and Regulation of the electric power industry, which is charged with the regulation of the interaction between private electric power producers, CDE, and consumers. Under the law the Directorate is responsible for developing regulations to promote in an orderly manner, private investment in the electric power subsector.

The Directorate is composed of the Ministry of Industry and Commerce, the Ministry of Finance, the Technical Minister of the President, and the Governor of the Central Bank of the Dominican Republic. An Executive Director is appointed by the President to oversee the operations of the Directorate.

As stated in the law, the Directorate is responsible for the following:

* Establishing private power tariff rates;
* Defining the technical specifications of interconnection of private producers and CDE; and
* Supervision of contracts between private producers and CDE.

The Directorate also receives "petitions" from potential private power producers seeking approval of their projects and the granting of fiscal and other incentives provided under Law 14-90. As stated in the law, the "petitions" must contain the following information:

* Draft proposal with preliminary details on the engineering, cost, generation, and local participation;
* Technical and economic feasibility study;
* Investment document stipulating that the flow of funds will cover the amortization of the project;
* Itemization estimate of the dollar requirement for the period of the tax exemption will last (see incentives section below);
* Statement on the impact of the project on the national economy; and
* Study on the environmental impacts of the project.

The Directorate is charged, subject to the terms of reference to be developed under the regulations, with reviewing the "petitions" and granting approval of the project incentives.

d. Private Power Projects

The United States company, Seaboard Corporation, owns a 40 MW, barge-mounted diesel project that sells power to CDE. The project was developed by Transcontinental Capital Corporation Ltd. of Bermuda, a wholly owned subsidiary of Seaboard. The project was proposed under the emergency decree issued by President Balaguer in 1988, and is estimated to cost $22 million.

e. Private Power Incentives

The Government of the Dominican Republic offers fiscal incentives to private power project developers. Under the legislation, the incentives are approved by the Directorate and may include the following:

* 100 percent tax exemption from income tax payments on revenue generated by private electric facilities;
* Exemption from tax on property purchased for private electric facilities;
* Exemption from taxes on the formation of private electric companies;
* Exemption from commercial patent taxes;
* Exemption from taxes on imported or domestically purchased fuels, materials, lubricants and other articles purchase for the construction, operation, and maintenance of private electric facilities; and
* Guarantee of the supply of U.S. Dollars required for the importation of goods and services, the amortization of project debt, and the repatriation of profits from private electric facilities.

The tax exemption period corresponding to each project is twenty years dating from the resolution of approval of the Directorate. This period may be extended an additional five years, provided that at least one-half of the capital of the project is held by Dominican Republic nationals at the conclusion of the initial twenty year exemption period.

Similar to the Government of Pakistan, the Government of the Dominican Republic also guarantees the contractual performance of its utility, CDE, regarding the sale and purchase of electric power, provided that the contract has been authorized by the Executive Power.

B. SETTING A PRICE FOR PRIVATELY GENERATED POWER: AVOIDED COST

1. Overview

Experiences in other countries have shown that establishing the methodology for calculation of avoided costs is a very sensitive and time consuming issue. It is acknowledged and accepted by the private sector that the price paid and resources developed should promote the development of the least cost generation plan for Kenya. At the same time, given the risks of developing geothermal resources, development of the first-ever private power project in Kenya, foreign exchange and institutional and other risks, the price paid for power needs to offer adequate incentives to private developers. In principle, the method for determining the price to be paid should be simple to use, and permit adjustments over time for contingencies which might arise such as changing exchange rates, taxes, cost of doing business in Kenya, etc. It is critical that any agreement be adequate to satisfy the financial community that the project presents a reasonable loan risk. Several of the alternatives for determining the price, or establishing a basis for determining the price, of private power sold to Kenya Power and Lighting or Kenya Power Company is the subject of the discussion below.

a. Avoided Cost

One of the most common bases for determining price to be paid for purchased power is the so-called "avoided cost." In the United States following the implementation of the 1978 Public Utilities Regulatory Policy Act, electric utilities were required to purchase power from private generators at "avoided cost". These avoided costs consisted of two parts, an energy component, which was based on the short-run incremental operation cost of the utility less losses; and a capacity component, which was based on the marginal cost of new capacity. The basic objective of avoided cost pricing is to find a fair and readily implementable means for determining the value to the utility for additional private generation.

There has been substantial experience in the application of avoided cost principles in the United States, however determinations are always subject to negotiation. Several key factors enter into the valuation of, and computation of price to be paid for private power purchases. The most prominent of which are:

* reliability--to what extent will the power generated be available when needed and in the amount needed.

* energy and capacity value of power--how are the values for kWh's and kW's supplied to be determined. What costs are displaced by private power sources, are these merely

short-run operating costs (e.g. for cogenerators of small amounts of non-firm power) or do they include new capital investment by the utility.

* avoiding commitments to unnecessary capacity--how does the utility ensure sufficient capacity investment while avoiding overcommitting to private generation and therefore incurring excess costs.

* impact on subsequent generation expenditures and timing and valuation of these effects--how to determine the value of private power in terms of future deferral of new capacity or other expenditures.

* balancing incentives with consumer costs--ensuring an adequate incentive for the private developer while not burdening the system with unnecessary costs.

Many approaches have been applied to determination of avoided costs, and several are discussed briefly here for background.

1. **Component Approach** In this method short-run marginal operating costs of the utility are used for valuing energy supplied, and capital costs avoided are assumed to be equal to the costs of a new combustion turbine or other peaking facility. This approach is convenient and relatively easy to calculate. However, the approach also underestimates actual avoided cost, as the long-run costs of new baseload generation would obviously be higher than a peaking unit. Other current and long-run system effects would also be excluded.

2. **Differential Revenue Requirements Method** This approach requires the modeling of the system over a substantial period of time, e.g. 25 years, with the development of a least-cost expansion plan for the period. Addition of the private power project into the plan is used to generate a revized least-cost plan, together with revized revenue requirements each year. Differences in revenues (savings due to the private project) are the amounts which could be paid the private generator. The complexity of this approach is the principal disadvantage, with the utility possibly the only party with access to all the data and capability to run the necessary model. The smaller the increment of capacity added by private generation in relation to the system, the less cost-effective this approach. Nonetheless, with access to data, agreement on assumptions and openness regarding the methodology by the utility, this method is probably the closest approximation to the "correct" result.

3. **Proxy Approach** This approach is similar to the component approach in that it utilizes the capital and operation cost of an "avoidable" unit in the generation mix. Rather than only use a peaking unit however, it is more normal to use the next expected

generation unit as the basis for estimated avoided cost payments for the private generator. The method is very simple, however it is likely to be only a rough estimate in that it does not consider other system effects or costs based on the planned dispatching of the "avoidable" unit, or project timing. Differences in reliability of the private versus utility generation are normally included.

4. Competitive Bidding This approach is meant to approximate the results of a free-market for capacity. It is normally based on the utility requesting offers according to type and size of capacity, timing, reliability, and baseload-intermediate-peaking needs. The utility would compute its avoided cost, e.g. utilizing the differential revenue method above, to establish a baseline for evaluating proposals. Based on the efficiency, cost of capital and other criteria of the bidder, the utility would hope to obtain power at or below its avoided cost. Other factors than price would affect the evaluation, including the utilities judgement of the capability of the bidder, fuel type and future cost of fuels proposed, type of generation and perceived reliability and performance, etc. Furthermore, this method would only work with a substantial number of willing bidders, with the utility committed to purchase, and with the utility willing and able to facilitate arrangements once bids are accepted.

5. **Alternative Approaches for Special Situations** Where the size of individual projects is likely to be small, e.g. in systems with cogeneration of electricity and steam, or with initial small private projects, another option is the "standard offer". That is, after considering its avoided cost, the utility prepares a standard offer similar to a public tariff. This approach avoids costly negotiation and analysis by the private generator, and is likely to be very conducive to sales from small-generators. The offer will normally differentiate respectively, between only energy purchases, firm capacity supplied, dispatchable capacity, etc. This method can also be applied to larger generation units, although given the much greater capital requirements and risks involved, it is likely that such sales will always require substantial negotiation on price and terms in any event.

6. **Incremental Costs** In tariff setting, the principle that rates should equal long marginal cost has been fairly-well accepted as economically correct. This basis should ensure that national economic resources are allocated efficiently within the power sector. This principle when applied to tariffs results in a fair allocation of costs amoung customers according to the costs they impose on the system, assures reasonable price stability and raises sufficient revenue to meet financial requirements of the utility. Applying this principle to power supplied leads to a similar result, that is, power supplied is worth the long-run incremental cost "avoided". The long-run incremental cost analysis therefore provides a result, on a kWh supplied basis, similar to the

differential revenue analysis above. Long-run incremental cost however, is often calculated without explicit consideration of the multitude of financing methods for each unit of capacity, and therefore may give results somewhat different that a differential revenue analysis (based on a detailed financial model).

b. Application of Avoided Cost Principles in Developing Countries

There are a number of critical differences in determining avoided costs in the developing country context that must be noted. The methodologies above all assume some estimation of the utilities revenue requirements utilizing the utilities normal financial model. Revenue would correspond closely to the actual financial costs. In using these methods in a developing country for power purchase pricing, however, substantial divergences in avoided cost theory occur, and require adjustment of terms. These occur for the following major reasons:

First, developing countries receive substantial subsidies in terms of grants and below market interest loans which do not reflect "economic" or free market values, nor certainly the cost of private development.

Comment: Since concessional or below-market rate loans (e.g. IDA financing) for power supply are normally strictly limited in total, deplacing these from the power sector into other development projects involves no loss to the country. In fact, since private foreign investment and often domestic private finance is scarce, additional capital offered as part of the private project is a net gain to the country.

Second, large-scale power generation development is a risky undertaking, particularly so where actual resource exploration is required as with geothermal development.

Comment: It is necessary and appropriate to add to avoided costs in the differential reveneue calculation, the benefits of avoiding substantial risky or costly development expenditures such as with geothermal resources.

Third, there are great management and logistics and cash flow problems facing an electric utility growing at rates of 5-6% per year, that is, with peak demand doubling in 12-14 years.

Comment: Introducing private financing, management and technical expertise as a complement to the utility, initially at low levels, is an excellent way for the utility to cope with high rates of growth, financial constraints and technical uncertainties. The U.S. example clearly demonstrates this principle, in fact between 1980 and 1985 more than 800 private power producers filed applications for over 24,000 MWs of new capacity. Electricity production from private producers grew by 64% during this period, while total electricity production grew only 6%.

Based on the revenue above it was determined that for purposes of this study, two basic comparisons would be most useful as a starting point. First, the results using the differential revenues methodology. And second, estimating the annual and average incremental cost of power. Given the limitations of this prefeasibility study we were not able to fully simulate the results using the differential revenue methodology. Nonetheless, judging this approach to be one of the best, we have attempted to approximate results of using this method in Section I. Our rough estimates we feel provide good representative values regarding differential annual revenues requirments with and without the private project. We have also provided estimates of annual and average incremental cost per kWh as another conventional basis for determining the value of private power.

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Section VII. PRIVATE POWER PROJECT FINANCIAL ANALYSIS

A. INVESTMENT CLIMATE IN KENYA

1. Historical Overview

Since independence, the Government of Kenya has encouraged foreign and local private investment and has provided adequate measures to safeguard private enterprises. Kenya has followed a basic economic policy that emphasizes the role of the free market. Features of this system include the use of market-based pricing incentives, a liberal investment code, flexible exchange-rate management, and a fairly appropriate fiscal policy. Nevertheless, impediments to a free market economy still exist. The government is heavily involved in key sectors of the economy, and many parastatal organizations do not make efficient use of government funds. Foreign corporations in Kenya complain of excessive bureaucracy causing lengthy delays in obtaining government approvals for projects.

2. Economic Overview

Kenya's economic performance has been fairly strong during the past 5 years. The growth rate of the country's real Gross Domestic Product (GDP) averaged 5.1% per year between 1985 and 1989. The Government's major contribution to this success has been the provision of an enabling environment through trade liberalization, reduction of average level of tariffs, budget rationalization and appropriate monetary policies. In 1989, overall GDP, which had risen by 5.2% in 1988, grew at a more moderate rate of 5.0%.

There has been double-digit inflation in recent years. The rate of inflation was 10.7% and 10.5% in 1988 and 1989 respectively. A major cause of inflation was the increased cost of imported machinery and intermediate inputs (petroleum).

Kenya's main foreign exchange earners are tourism, coffee and tea. Kenya's US$815 million export earnings the US$1.5 billion (1989) imports leave a large deficit financed mainly by capital inflows, including foreign aid. Coffee and tea account for slightly over half of total exports. Horticulture, a rapidly expanding export item, provides over US$50 million annually.

Kenya has a good transportation system and telecommunications network. Nairobi, the capital, and Mombasa, the largest Indian Ocean port between Karachi and Durban, are the hubs of Kenya's infrastructure. Nairobi has an international airport served by more then 25 airlines. Kenya is considered to have generally dependable electric power, industrial fuel and water supplies. Inadequate maintenance of the physical infrastructure, however, threatens

industrial expansion. Kenya is represented by all major international development agencies and a number of foreign private banks.

3. Government Attitude Toward Foreign Private Investment.

The Kenyan government continues to publicly encourage foreign investment. In his 1988 and 1989 Government Budget Speeches, the Minister of Finance testified to the Government's need to improve the investment climate. The government is aware of the critical role foreign investment plays in generating employment, new skills and foreign exchange. However, there remain difficulties related to the slow pace of removal of investment disincentives, such as excessive regulation, profit and dividend repatriation, restrictive industrial and banking laws, foreign exchange limitations, and rising levels of bureaucratic "red tape".

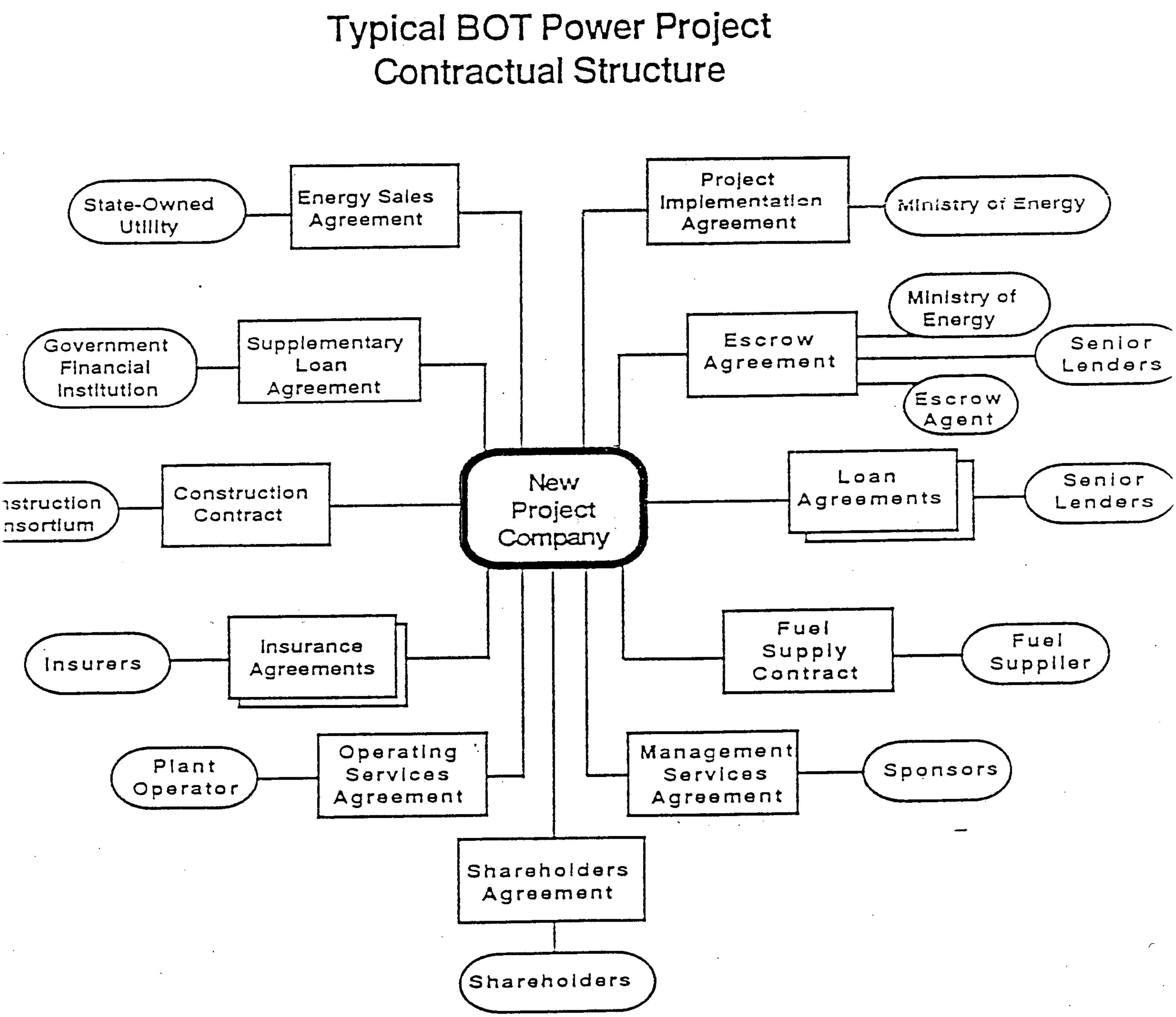
B. OPTIONS FOR PRIVATE POWER DEVELOPMENT IN KENYA

There are many financial and corporate structures which accommodate the needs of the private investor, the local utility and the government in a private power project. Typically, a private developer sets up a foreign corporation in a joint-venture relationship with the local utility. The joint-venture corporation can provide off-balance-sheet financing, and is structured to share the risk and rewards of the project. Certain performance guarantees are required. These are usually obtained through contractual obligations, deficiency agreements or other similar agreements that ensure that the debt service to the project will be paid. Such type of agreements are discussed in detail in Section VIII of this report.

The most common structures for privately owned and financed projects are (a) the Build, Own and Transfer structure (BOT), (b) the Build, Own and Operate (BOO) structure, with no transfer, and (c) the Build, Operate and Lease structure (BOL), where the private developer builds and owns the project but leases the plant to a government entity. Figure VII-1 illustrates a typical BOT structure.

In a BOT, a private developer finances, builds, owns and operates a power plant, and sells power to the electric utility under a power purchase agreement for a prescribed term (which commonly varies from 10 to 15 years). After the agreed-upon term, the title to the power plant is transferred to the utility, and the utility assumes full responsibility for ownership and operations. Foreign exchange is used to service debt and pay a return to foreign joint-venture participants; and local currency is used to pay local returns and to fund construction, operating and maintenance costs.

FIGURE VII-1. BUILD, OWN AND TRANSFER BOT STRUCTURE.



Typically, the following conditions are necessary for the successful implementation of a BOT project:

1. The project must be economically viable.

2. Investors and lending agencies will require adequate security/collateral, and a repayment stream in the currency of the investment in order to service its debts and provide an adequate return on investment.

3. The Government must be credit-worthy, and must agree to pay for the generated electricity at a realistic price for the term of the equity investment.

4. The foreign lenders and project sponsors need assurance that there will be no interference with the conditions and terms agreed upon in the contract during the operational phase of the project until project ownership has been transferred to the government. This includes such project management issues as removal of employment restrictions, tax and duty exemptions, etc.

C. PRIVATE POWER FINANCING ISSUES

The following issues are considered extremely important to financing agencies when considering funding a private power project:

1. Ability to negotiate necessary contracts: Government approval must be timely and satisfactory to lending agencies.

2. Construction delays: Cost overruns, delays and contractor problems must be avoided. Therefore, the selection of the prime contractor is of extreme importance.

3. Performance output shortfalls: The size of the resource must be tested and proved by independent consultants.

4. Exchange rate fluctuations: Debt and return payments should match the currency of the lending agencies or should have escalation clauses or escrow accounts.

5. Environmental permitting problems: Environmental opposition can cause lengthy delays. Projects should be designed to avoid environmental issues.

6. Technical failure: Unexpected technical problems, such as obsolete equipment or new, untested equipment, can cause delays.

D. POTENTIAL ROLE OF KENYA POWER AND LIGHTING COMPANY, LTD.

Experience in other developing countries has shown that the utility company participation in the private power project leads to better acceptance of the project by the government and investors and to more effective project performance. Some of the potential roles of the foreign developer and local utility are:

1. Utility company responsibilities include:

   -calculation of avoided costs.
   -establishing standards for drilling, construction and operation phases.
   -negotiating terms for power purchase contracts.
   -establishing a system for reporting electric purchases.

2. Project sponsors responsibilities include:

   -submitting proposals.
   -conducting technical and economic feasibility studies.
   -arranging financing.
   -negotiating agreements with equipment suppliers, construction contractors and other related services.
   -negotiating terms for power purchase contracts.
   -conducting drilling, field development and construction operations.

E. FINANCING OPTIONS

1. Traditional Sources of Capital

a. Project Sponsor.

The project sponsor is typically a party to the joint-venture, and normally contributes the equity or risk portion of the project's capital. This may include cash, capitalized equipment, technology transfer or in-kind services. Project sponsors often provide overrun funding (subordinated loans) and completion guarantees.

b. Commercial Banks.

The principal advantages of obtaining loans from a commercial bank are the availability of funds and funding flexibility. Commercial banks generally have medium terms (5-10 years) at a floating interest rate. It is common for a major project to obtain a syndicated loan, wherein the lead bank seeks participation from other large commercial banks to fund a sizeable portion of the project.

c. **Export Credit Agencies.**

The most common form of export credit support is provided by major government agencies of the suppliers' countries. This support can include direct loans, insurance, interest rate subsidies, and protection against inflation and exchange rate risk.

d. **Bilateral Aid.**

Projects in certain countries may be eligible for bilateral aid. This aid is usually highly concessionary (low interest rates and long grace and repayment periods). Such aid can be useful in providing technical assistance, funding feasibility studies or funding infrastructure. Disadvantages of bilateral aid are that it is generally not available in large amounts to any one country on a continuing basis, and it is frequently tied to procurement from the country providing the funds.

e. **Multilateral Development Banks.**

The multilateral development banks are a frequent source of funding for projects in developing countries. The major institutions in this category for Sub-Saharan Africa are the World Bank (and its affiliated institutions, the International Development Association and the International Finance Corporation), and the African Development Bank. Development bank funding is divided into soft loan lending (low or zero interest rates and long maturities of 30-40 years) and hard lending (higher but still below-market interest rates and shorter maturities of 15-20 years). In addition to providing financing, development banks can provide assistance in conducting feasibility studies, and infrastructure support.

2. **Local Sources of Funds**

Domestic capital markets in developing countries are often underutilized, and could provide local financing for a private power joint-venture. Kenya has recognized the importance of these markets and is seeking to expand them. In 1989, the Government of Kenya established a Capital Markets Authority. This Authority has been directed to create instruments and a trading mart for the development of an active, effective and efficient securities market in Kenya. It is also expected to provide additional sources of investment financing, especially since the current long-term credit market is largely non-existent.

The Kenyan banking system consists of the Central Bank, 24 commercial banks (which include Kenya Commercial Bank, Barclays Bank, Citicorp, Standard Chartered Bank, and National Bank of Kenya), and about 50 non-bank financial institutions. Two equity capital companies, Industrial Promotion Services Ltd. (IPS), and Kenya Equity Capital, Ltd., provide venture capital for medium-sized investments.

3. Other Sources of Funds

Current economic conditions in many developing countries have required creative financing methods for large, capital-intensive projects. Some of these are:

a. Private equity financing.
b. Debt-equity swaps.
c. Sale of power directly to the end user.
d. Joint venture with a local oil or gas company.
e. Lease options.
f. Expansion and development of local capital markets.
g. Debt-energy swaps.

All of the options listed above are potential financing mechanisms for use in a Kenya private power project. The feasibility study for each specific geothermal project will address specific financing options for that project.

F. FINANCIAL ANALYSIS

The first stage in the selection of one or more geothermal project sites consisted of screening the various prospects, ranking them and eliminating those that were clearly unattractive or uneconomical. Installed costs for the most attractive prospects were then computed. This revealed significant cost sensitivity in relation to the size of the geothermal power plant. The following financial analysis is based on the 3 most likely prospects (Suswa, Eburru and Arus) as outlined by GeothermEx in Section IV. Installed cost and plant operating costs were taken from data provided in Section V prepared by the Ben Holt Company.

1. The Financial Model

A spreadsheet financial model was developed, using Lotus 123 software. This model was used to analyze various scenarios based on different financial assumptions and sensitivity. The model includes an interactive set of assumptions, an income and expense statement, sources and uses of funds statement, and loan payment schedules. From this, cashflows were analyzed and internal rates of return (IRR) and net present values (NPV) were calculated for each prospect. Dividends were not levelized or restricted in this analysis. Copies of the spreadsheets for Suswa, Eburru and Arus are included in Appendix IV.

2. Financial Assumptions

a. Time Line:

-Construction periods (exploration, drilling and design) vary by plant size, location etc.
-Project life is 25 years.

b. External Economic Assumptions:

-Kenyan inflation rate is 8% per year.
-Kenyan shilling devalues vis-a-vis the U.S. dollar at an annual rate equal to the Kenyan inflation rate (assumed to be 8% per year).
-Exchange rate is 23 KSh/US$ in 1991.
-Kenyan corporate tax rate used in this analysis is 42.5%.

c. Project Economics:

-Assumed capacity factor of 95% (plant is up and running 8,332 hours/year at rated capacity).
-O&M costs increase by 1% a year in KSh.
-Required payments are indexed to inflation.
-Project IRR's are calculated on after-tax cash flows for the length of the transfer period.
-Depreciation is calculated on a straight-line basis for this prefeasiblity study.
-Interest is capitalized during construction.

d. Deal Structure:

-Project is financed by 20% equity, 80% debt.
-No phase-in of equity takes place.
-Permanent financing takes place from a mixture of supplier credits, commercial bank loans and equity. Loan terms are varied in each scenario.

G. FINANCIAL SCENARIOS

Three scenarios have been developed for each geothermal prospect to calculate a payment that KPLC (or KPC) would make to the joint-venture company, based on various financing terms and a 20% hypothetical IRR. These scenarios assume a 10-year BOT, a 15-year BOT and a 25-year no-transfer BOO. Sensitivity analysis is performed for tax consequences assuming a 5-year tax-holiday and a no-tax-holiday example. The tax assumptions use a 42.5% rate (the corporation is not taxed by both governments) and, in the tax-holiday example, taxes are not paid in the first 5 years of the project. Hypothetical financing terms are used throughout this analysis and the project is financed by 20% equity and 80% debt.

Scenario 1 - This scenario assumes a 10-year BOT structure. The 80% debt financing includes 60% supplier's credit (10-year term, 8% interest) and 40% commercial credit (7-year term, 12% interest). Interest is capitalized at 10% during the construction period and the grace period is equal to the construction period for each prospect.

Scenario 2 - This scenario assumes a 15-year BOT structure. The 80% debt financing includes 60% supplier's credit (15-year term, 8% interest) and 40% commercial credit (7-year term, 12% interest). Interest is capitalized at 10% during construction and the grace period is equal to the construction period for each prospect.

Scenario 3 - This scenario assumes that no transfer of title occurs, and the plant is owned and operated by the joint-venture group for 25 years. The debt structure and interest rates are the same as those in Scenario 2.

The main difference in the 3 scenarios is that the IRR's are calculated on after-tax cashflows equal to the length of the transfer period (10 years, 15 years and 25 years).

H. RESULTS OF FINANCIAL ANALYSIS BASED ON PROJECT STRUCTURE AND TAX EFFECTS.

The information presented in Tables VII-1, VII-2 and VII-3 is based on payments required to satisfy a 20% IRR for each of the 3 prospects using Scenario 1 - 3 assumptions. IRR's for each prospect are computed using after-tax cashflows based on the length of the transfer period.

TABLE VII-1. SUSWA REQUIRED PAYMENT, BASED ON SCENARIO RESULTS AND RATE OF RETURN

Scenario Description	Required Payment, cents/kWh						
	5	5.5	6	6.5	7	7.5	8
10-Year BOT, Tax Holiday	-	-	9	24	41	63	92
10-Year BOT, No Tax Holiday	-	-	-	2	10	17	25
15-Year BOT, Tax Holiday	10	19	30	44	64	91	-
15-Year BOT, No Tax Holiday	6	11	16	22	28	35	43
25-Year BOO, Tax Holiday	16	23	31	45	63	89	-
25-Year BOO, No Tax Holiday	13	17	21	25	30	36	44

TABLE VII-2. EBURRU REQUIRED PAYMENT, BASED ON SCENARIO RESULTS AND RATE OF RETURN

Scenario Description	Required Payment, cents/kWh						
	7	7.5	8	8.5	9	9.5	10
10-Year BOT, Tax Holiday	-	5	18	31	47	67	92
10-Year BOT, No Tax Holiday	-	-	-	6	12	18	25
15-Year BOT, Tax Holiday	18	27	38	52	71	96	-
15-Year BOT, No Tax Holiday	11	16	20	24	30	35	43
25-Year BOO, Tax Holiday	21	28	39	53	71	96	-
25-Year BOO, No Tax Holiday	16	19	22	27	32	38	44

TABLE VII-3. ARUS REQUIRED PAYMENTS, BASED ON SCENARIO RESULTS AND RATE OF RETURN

Scenario Description	Required Payment, cents/kWh						
	7	7.5	8	8.5	9	9.5	10
10-Year BOT, Tax Holiday	-	-	3	14	26	38	55
10-Year BOT, No Tax Holiday	-	-	-	-	3	9	14
15-Year BOT, Tax Holiday	10	17	25	34	46	61	80
15-Year BOT, No Tax Holiday	6	10	14	18	23	27	33
25-Year BOO, Tax Holiday	16	21	27	35	47	62	81
25-Year BOO, Tax Holiday	13	16	19	22	24	28	33

I. ANALYSIS OF MOST LIKELY PROSPECTS

The following is a financial evaluation of Suswa, Eburru and Arus based on scenario results. Spreadsheet calculations for these prospects are included in Appendix IV.

Suswa. Suswa presents an attractive possibility of a large (50MW), rapidly explorable and developable resource. Its installed costs are US$2,538/kW (interest during construction is US$546/kW). It is estimated that exploration, drilling and construction can be completed in approximately 4 years. In Scenario 1, the 10-year BOT, assuming a required 20% IRR, required payment for Suswa ranges from $.064/kWh to $.077/kWh in the tax-holiday and, no tax-holiday examples. In Scenario 2, the 15-year BOT, the required payment ranges from $.056/kWh to $.064/kWh in the tax-holiday and no-tax holiday examples. In Scenario 3, the 25-year BOO, the required payment is $.053/kWh and $.059/kWh in the tax-holiday and no-tax holiday examples. Annual cashflow for Suswa fluctuates in the first 15 years of the project due to loan-termination periods. In the 15-year BOT scenario, assuming a $.056/kWh tariff, Suswa has a positive net present value (NPV) using 10%, 12% and 14% discount rates. However, please note that IRRs will change for all candidate prospects once cashflows are levelized for debt-coverage payments and dividend restrictions.

Eburru. Eburru offers an opportunity for immediate development of a resource of moderate potential (20MW). Its installed costs are US$3,034/kW (interest during construction is US$484/kW). Because of the advanced stage of exploratory drilling, it is estimated that construction can be completed in approximately 3 years. In Scenario 1, the 10-year BOT, assuming a required 20% IRR, the required payment ranges from $.082/kWh to $.096/kWh in the tax-holiday and no-tax-holiday examples. In Scenario 2, the 15-year BOT, the required payment ranges from $.071/kWh to $.08/kWh in the tax-holiday and no-tax-holiday examples. In the Scenario 3, the 25-year BOO, the required payment ranges from $.069/kWh to $.076/kWh in the tax-holiday and no-tax-holiday examples. Annual cashflows for Eburru fluctuate from year to year, due to loan-termination periods. In the 15-year BOT scenario, assuming a $.071/kWh tariff, Eburru has positive NPV assuming a 10%, 12% and 14% discount rate.

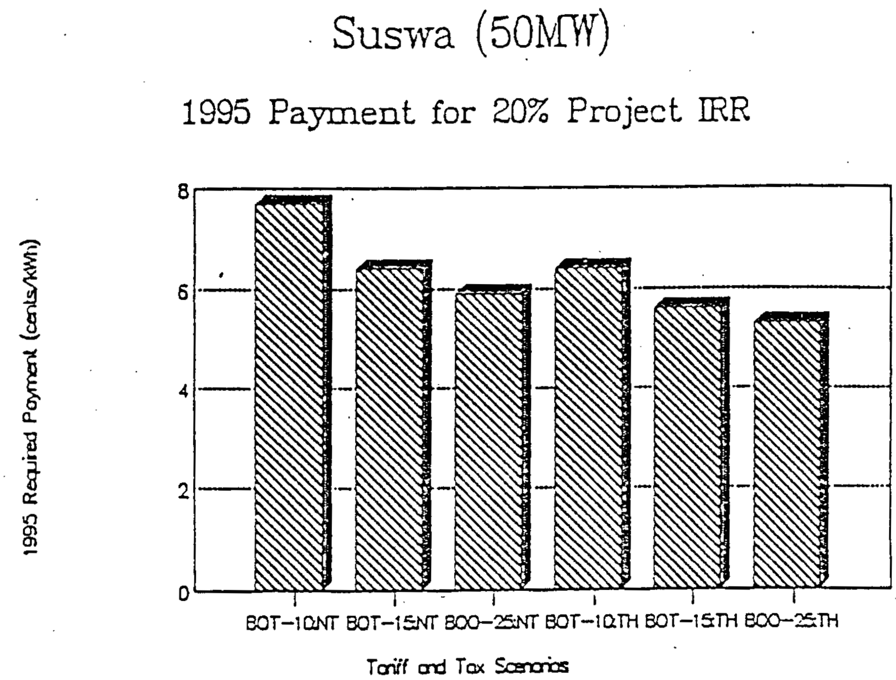
Arus. Arus offers an opportunity for immediate drilling into a resource of moderate potential (20MW). Its installed costs are US$3,324/kW (interest during construction is US$714/kW). Because it is accessible and easily identified, it is estimated that construction can be completed in approximately 4 years. In Scenario 1, the 10-year BOT, assuming a required 20% IRR, the required payment for Arus ranges from $.087/kWh to more than $.10/kWh in the tax-holiday and no-tax-holiday example. In Scenario 2, the 15-year BOT, the required payment ranges from $.077/kWh to $.086/kWh in the tax-holiday and no tax-holiday examples. In Scenario 3, the 25-year BOO, the payment ranges from $.074/kWh to $.082/kWh. Annual cashflows from Arus fluctuate from year to year, due to loan-termination periods. In the 15-Year BOT, assuming a $.077/kWh, Arus has a positive NPV assuming a 10%, 12% and 14% discount rate.

1. Analysis of Transfer Period and Tax Holiday

To illustrate the effect of transfer period on required return, Suswa is used as an example in Figure VII-2. In the 10-year BOT, 15-year BOT and 25-year BOO, no tax holiday scenarios, the required payments for Suswa are $.077/kWh, $.064/kWh and $.059/kWh respectively. In the tax holiday scenarios, the required payments are $.064/kWh, $.056/kWh and $.053/kWh respectively. This indicates that length of transfer period can reduce required returns by more than $.01/kWh (tax scenario case).

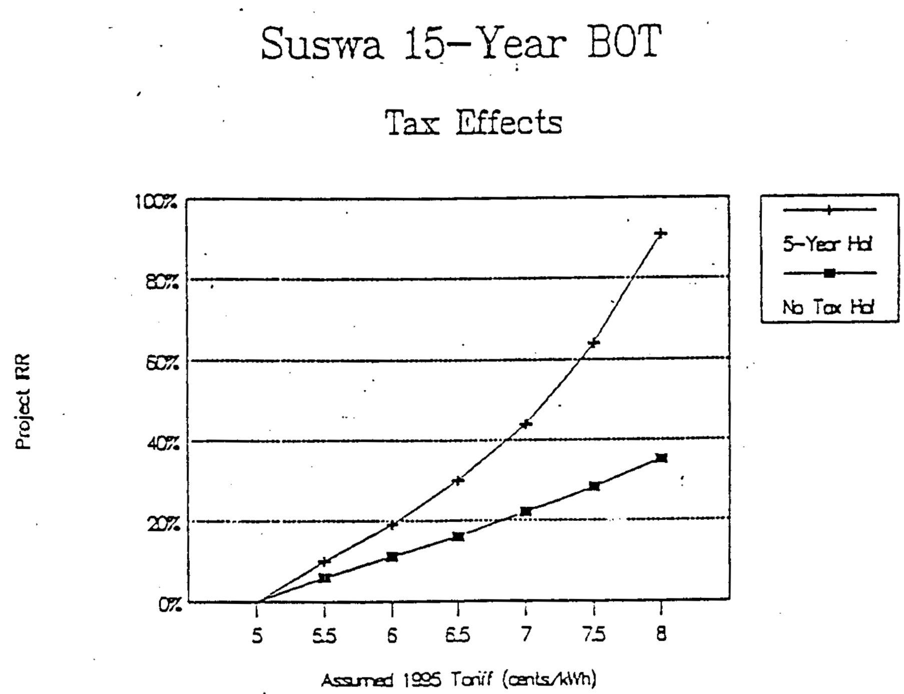
To illustrate the effect of tax concession on required return, using Suswa's 15-Year BOT as an example, Figure VII-3 illustrates the required payment based on a 20% IRR. These payments range from $.064/kWh in the no-tax-holiday example to $.056/kWh in the tax-holiday-example. This is almost $.01/kWh less, due to elimination of tax payments for 5 years.

FIGURE VII-2. REQUIRED PAYMENT, SUSWA



Legend: NT = no tax; TH = tax holiday.

FIGURE VII-3. SUSWA 15-YEAR BOT



J. SENSITIVITY ANALYSIS OF KENYA POWER AND LIGHTING COMPANY AND PRIVATE POWER PROJECT.

The following analysis was performed to derive a comparable KPLC cost to build a 32 MW geothermal power plant. The assumptions used in this analysis were taken from information prepared in Section III of this report.

Assumptions

Project size	32 MW
Capital costs (includes US$703/kW interest during construction)	$3,065/kW
O&M	8 mills/kWh
Capacity factor	80%
Project life	25 years
Equity	20%
Debt	80%
Interest rate	7.5%
Term	20 years
Construction period	7 years
Grace period	7 years
Kenyan tax rate	39%
After-tax return on equity	7.5%
Plant costs (US$000)	$98,080

Based on these assumptions, KPLC's tariff, assuming 7.5% after-tax return on equity and a 7.5% interest rate on debt, is approximately $.047/kWh. Several qualifications are in order when comparing this figure to the required payments for a private power project calculated in this study. KPLC's capital cost per MW is based on a 32MW plant, and the private power projects are based 20MW and 50MW plant size. Additionally, KPLC's cost of capital and return on equity are substantially lower than market-based rates for this type of project.

1. Sensitivity Analysis

The following cases present sensitivity analysis demonstrating terms which would make a private power project's costs more comparable to KPLC's project costs assuming various capacity factors, rates of return and interest rates. Unless stated otherwise, the information presented herein assumes KPLC has an 80% availability factor, a 7.5% return on equity and a 20-year loan (7.5% interest rate). The private power project assumes a 95% availability factor, 40% commercial loan (7-year term, 12% interest rate), 60% suppliers' loan (15-year term, 8% interest rate) and a 20% IRR. Both KPLC and the private power project capital cost per kW include interest during construction (8% and 10% respectively).

CASE 1 - Capacity Factor

Private Project:	KPLC has no tax-holiday, 7.5% ROE, 25-year project life.
	Suswa has a 5-year tax-holiday, 20% IRR, 15-year and 25-year project life.
Public Project:	KPLC has no tax-holiday, 7.5% ROE, 20-year loan term, 25-year project life.
	Suswa has no tax-holiday, 20% IRR, 20-year loan term, 15-year and 25-year project life.

CASE 2 - Rate of Return

Private Project:	KPLC has no tax-holiday, 80% capacity factor, 25-year project life.
	Suswa has a 5-year tax-holiday, 95% capacity factor, 15-year and 25-year project life.
Public Project:	KPLC has no tax-holiday, 80% capacity factor, 20-year loan term, 25-year project life.
	Suswa has no tax-holiday, 95% capacity factor, 20-year loan term, 15-year and 25-year project life.

CASE 3 - Interest Rates

Private Project:	KPLC has no tax-holiday, 7.5% ROE, 80% capacity factor, 15-year loan term, 25-year project life.
	Suswa has a 5-year tax holiday, 20% IRR, 95% capacity factor, 15-year loan term, 25-year project life.
Public Project:	KPLC has no tax-holiday, 7.5% ROE, 80% capacity factor, 20-year loan term, 25-year project life.
	Suswa has no-tax holiday, 20% IRR, 95% capacity factor, 20-year loan term, 25-year project life.

Table VII-4. COST COMPARISON OF TARIFFS FOR PRIVATE VERSUS PUBLIC PROJECT

Description		25 Yr. KPLC (c/kWh)	15 Yr. BOT Suswa (c/kWh)	25 Yr. BOO Suswa (c/kWh)
CASE 1 - Capacity Factor. Rate of return is held constant and capacity factor is analyzed.				
Private Project -	80%	5.3	6.5	6.3
	85%	5.1	6.2	6.0
	90%	5.0	5.8	5.6
	95%	4.9	5.6	5.4
Public Project -	80%	5.0	5.4	5.2
	85%	4.8	5.1	4.9
	90%	4.5	4.8	4.7
	95%	4.3	4.6	4.5
CASE 2 - Rate of Return. Capacity factor is held constant and rate of return is analyzed.				
Private Project -	7.5%	5.4	4.8	4.0
	10%	5.6	5.0	4.4
	15%	7.2	5.3	5.0
	20%	8.1	5.6	5.4
Public Project -	7.5%	5.0	4.0	3.6
	10%	5.3	4.1	3.8
	15%	5.7	4.4	4.1
	20%	6.2	4.7	4.5
CASE 3 - Interest Rate. Capacity factor and rate of return vary and interest rates are analyzed.				
Private Project -	7%	5.0	4.8	4.6
	8%	5.2	4.9	4.7
	9%	5.4	5.1	4.9
	10%	5.6	5.3	4.5
Public Project -	7%	4.8	4.5	4.4
	8%	5.0	4.7	4.5
	9%	5.3	4.9	4.7
	10%	5.5	5.0	4.9

Table VII-4 illustrates different tariffs for a private versus public project based on sensitivity analysis of capacity factors, rates of return and interest rates. This information is also presented graphically in Figures VII-4, VII-5 and VII-6.

In Case 1, capacity factor sensitivity, rate of return is held constant and capacity factor is analyzed. In the private project example, at an 80% capacity factor, KPLC's tariff of $.053/kWh is closest to Suswa's 25-Year BOO project, 95% capacity factor ($.054/kWh). KPLC's costs are lower in this example due to its lower required return. In the public project example, KPLC's 80% capacity factor tariff is comparable to Suswa's 25-Year BOO required payment at 85% capacity ($.05/kWh vs. $.049/kWh). At 95% capacity factor however, Suswa's required payment becomes less than KPLC's tariff at an 80% capacity factor, in both the 15-Year BOT and 25-Year BOO projects. Financing costs are lower in the public project example but KPLC's higher capital cost ($3,065/kW vs. $2,538/kW) make private power less expensive. Comparing capacity factor sensitivity between the public and private projects, the most likely comparison, we find KPLC's 80% capacity factor tariff is most comparable to Suswa's 25-Year BOO required payment, 95% capacity factor ($.05/kWh vs. $.054/kWh), based on required returns of 7.5% and 20%.

In Case 2, rate of return sensitivity, capacity factor is held constant and rate of return is analyzed. In the private project example, KPLC's tariff, assuming a 7.5% return, is comparable to Suswa's 25-Year BOO required payment assuming a 20% rate of return ($.054/kWh vs. $.054/kWh). In the public project, KPLC's tariff, assuming a 7.5% rate of return, is greater than Suswa's 15-Year BOT and 25-Year BOO required payments assuming a 20% rate of return. This is due to KPLC's lower availability and higher capital costs. If KPLC's project were privately financed and a 20% IRR were required, KPLC's tariff could be as high as $.081/kWh.

In Case 3, interest rate sensitivity, assuming base case capacity factors and required returns, the effect of different interest rates on project costs are analyzed. At an 80% capacity factor and 7.5% required return, KPLC's tariffs are similar to the private power project required payments (95% capacity factor, 20% IRR) in both the private and public examples (only loan terms are varied). Costs become comparable in this case due to KPLC's higher capital cost and private power projects increased availability, lower capital costs and higher required return. Interest rate sensitivity is an important factor in this analysis because private power financing cannot compete with KPLC's subsidized rates. Based on the type of equipment financing obtained, and, if either donor funds and/or grants are obtained, private power's financing terms can compare favorably to KPLC's interest rates.

This analysis demonstrates that given higher availability (efficiency), lower capital costs (reduced construction time) and interest rates which are comparable to KPLC's (this implies a portion of the financing could be either donor financing or grants), a private power project can compete with KPLC's subsidized costs for a planned or proposed geothermal project. It should also be mentioned that based on accepted methodologies for computing avoided costs, KPLC's systemwide avoided costs would be higher than the amounts listed above (geothermal plant costs are only one component of this calculation). Methodologies for computing avoided costs are discussed in detail in Section VI, Part 2.

FIGURE VII-4. COST COMPARISON PRIVATE VERSUS PUBLIC PROJECT, CAPACITY FACTOR

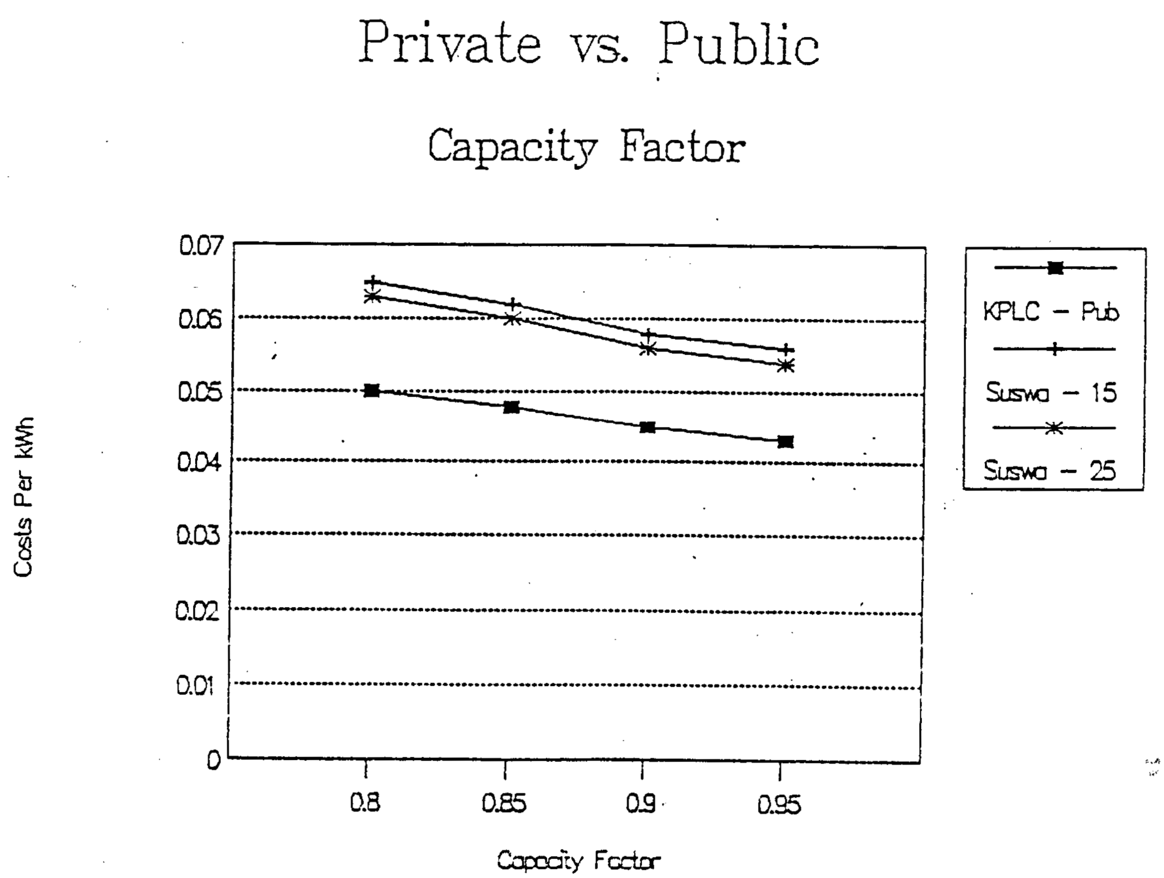


FIGURE VII-5. COST COMPARISON PRIVATE VERSUS PUBLIC PROJECT, RATE OF RETURN

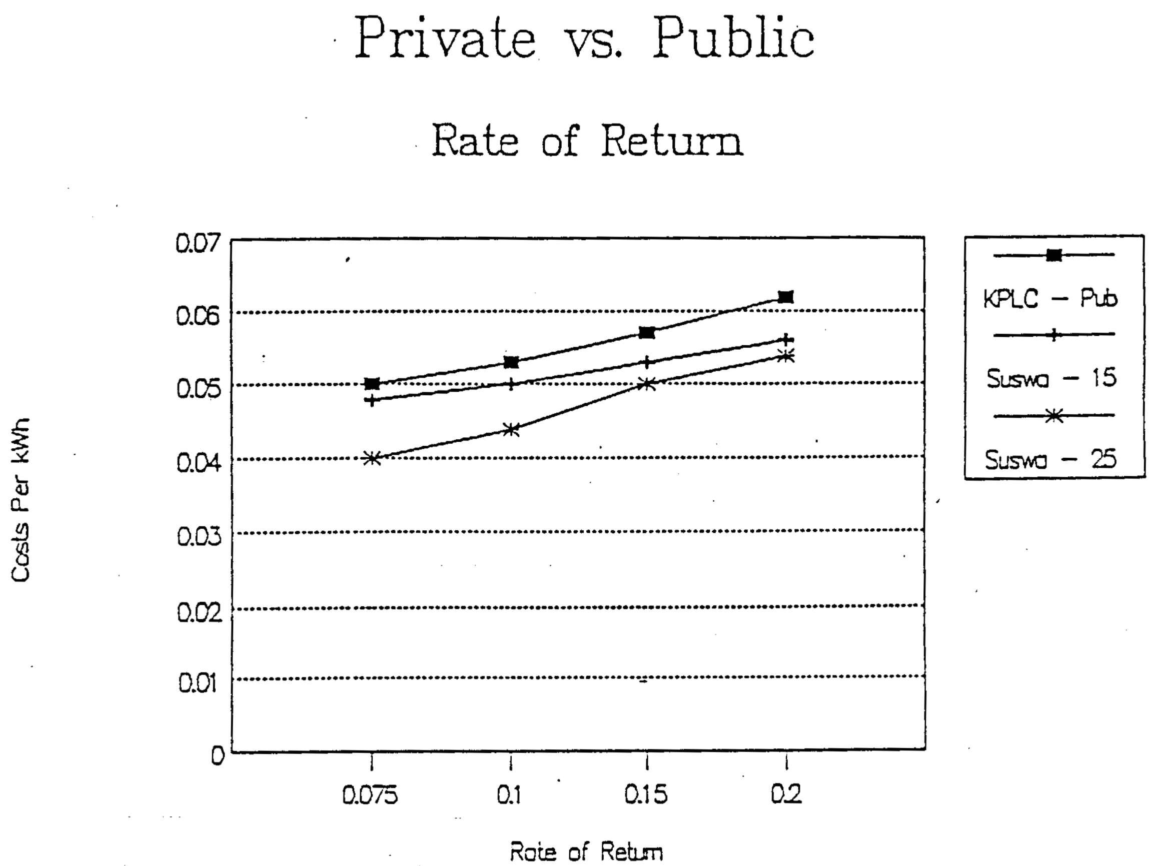
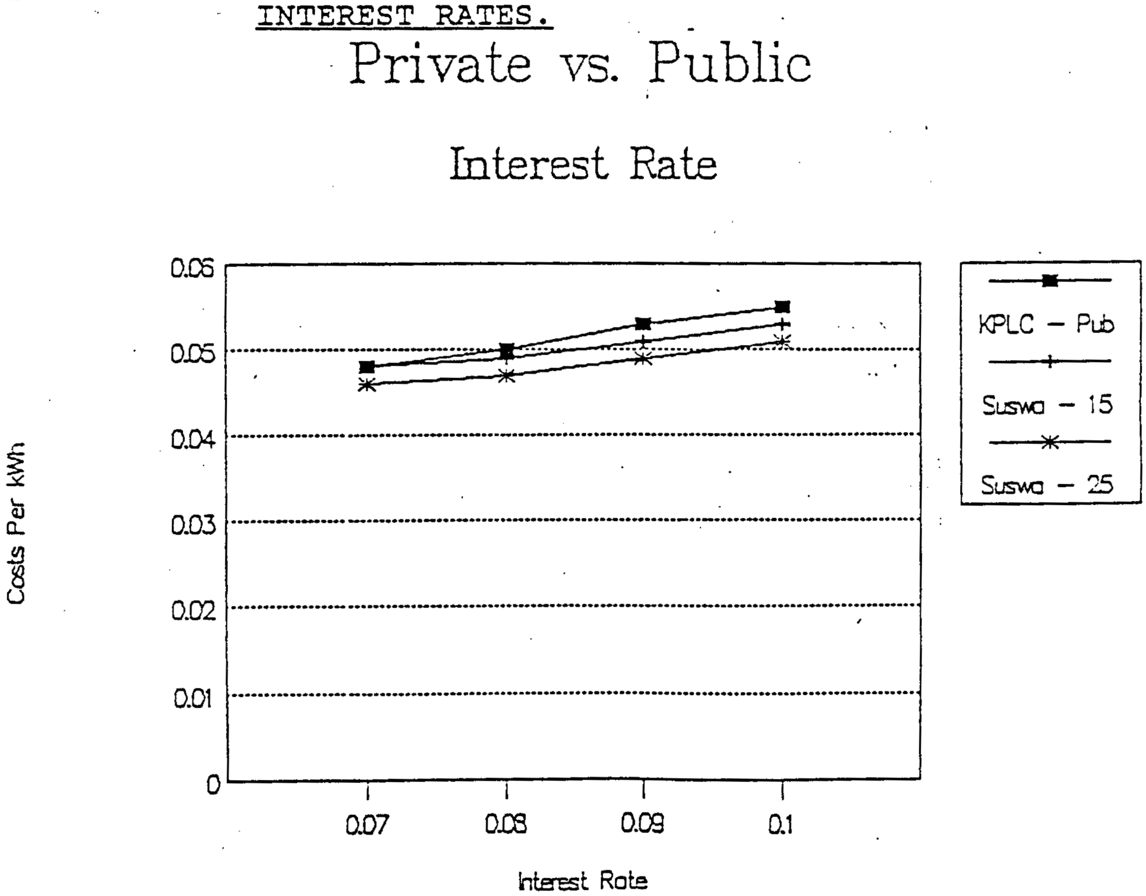


FIGURE VII-6. COST COMPARISON PRIVATE VERSUS PUBLIC PROJECT, INTEREST RATES.



K. CONCLUSION

This prefeasibility study has attempted to demonstrate the advantages of a private power project, and look at the returns an international investor would require in order to finance this type of project. The advantages of private power are many. Private power developers (1) arrange for and assume all the risk of financing and constructing the power project, (2) provide off-balance-sheet financing, (3) establish an avoided cost for future projects, (4) help improve efficiency standards for other power projects, and (5) provide technology transfer for new products and services. In terms of financing costs, private power projects cannot compete directly with KPLC's highly subsidized rates. Private power can, however, free KPLC limited capital for use on other projects. Other favorable factors which make costs more comparable include increased availability and reduced construction time. Also, when considering the limits on availability of concessionary financing to KPLC, and the constraints being imposed by concessionary lenders, the price disparity between a public and a private power project becomes less both in amount and in importance.

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Section VIII. LEGAL ISSUES RELATING TO THE DEVELOPMENT AND SALE OF PRIVATE-SECTOR GEOTHERMAL POWER TO THE PUBLIC SECTOR IN KENYA

A. THE KENYAN LEGAL AND REGULATORY FRAMEWORK: OVERVIEW

Power supply projects in Kenya are undertaken to meet both economic and social objectives, and, historically, have been the responsibility of the Government. In 1990, the Government of Kenya, realizing that the rate of growth of power demand is exceeding its ability to construct new generating capacity, opened the possibility for the private sector to participate in power supply--specifically power supply from geothermal sources. The basis for geothermal power supply is established in the Geothermal Resources Act, 1982.[1] The law vests all geothermal resources in the Government,[2] and establishes a regulatory framework, pursuant to which a private-sector developer may be licensed to enter a geothermal field, and drill, extract, generate and sell the resource.

This law was executed by the Minister of Energy eight years subsequent to its passage, and came into effect simultaneously with the promulgation of implementing regulations on May 1, 1990.[3]

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1 The Geothermal Resources Act, 1982, Law No. 12 1982 (Date of Assent 8 July 1982, Date of Commencement, by Notice). Full text appears in Appendix V.

2 Id. Part I, § 3.

3 The Geothermal Resources Act, 1982, Commencement, Legal Notice 205, April 24, 1990, Kenya Gazette, Supp. 33, 262 (May 25, 1990); The Geothermal Resources Regulation, 1990, Legal Notice 206, April 24, 1990, Kenya Gazette, Supp. 33, 262-283 (May 25, 1990). Full text appears in Appendix VI.

These implementing regulations make clear that transnational (foreign), private-sector corporations are eligible applicants for authority from the Government of Kenya to explore for geothermal resources and to be granted a license to drill and utilize geothermal resources, including utilization of the resources for the production of power.[4] It should be noted, however, that neither the law nor the regulations sets forth an express policy of encouraging private-sector development of geothermal resources. The statutory framework affords a discretionary mechanism which allows private-sector participation in geothermal power production, but stops shy of clearly endorsing policy of private-sector geothermal resource development.[5]

1. The Kenyan Legislative and Regulatory Approach

The Geothermal Resources Act, 1982, establishes a series of steps which the transnational geothermal developer must follow: (1) the Minister of Energy must first authorize all resource exploration;[6] (2) a "geothermal resources license" must be obtained from the Minister in order for the developer to drill, extract, and utilize the resources,[7] and (3) if electricity is to be produced the developer must obtain a license under the Electric Power Act,[8] or if commercial by-products are reclaimed, the geothermal resources license must include a mining lease consistent

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4 The Geothermal Resources Regulations, §§ 1, 7, 18.

5 See, e.g., the statement of the Philippine government in setting forth the Act Authorizing the Financing, Construction, Operation and Maintenance of Infrastructure Projects by the Private Sector: "It is the declared policy of the State to recognize the indispensable role of the private sector as the main engine for natural growth and development and provide the most appropriate favorable incentives to mobilize private resources for the purpose." (Republic Act, No. 6957, July 9, 1990).

6 Geothermal Resources Act, supra note 1, at § 36. Such grant is for five years.

7 Id. § 7. Such grant is for 30 years, renewable for five years.

8 Id. § 14; Electric Power Act, Ch. 314, Law of Kenya 2-213 (1986). Power Sales under the Electric Power Act and the laws of Kenya is a somewhat complicated issue. For a detailed analysis, see Appendix VII.

resources license must include a mining lease consistent with the Mining Act.[9]

The Geothermal Resources Regulations, 1990, set forth a model license which establishes the basis for negotiating the arrangements for obtaining the rights to the Kenyan Geothermal resources license -- a "model Geothermal Resources License".[10]

This Model Geothermal Resources License provides that the right to take and use geothermal resources may be based in part on a geothermal contract, incorporated into the license by reference. The license establishes a schedule of payment for land rental and royalty for the sale of steam or electricity. It provides for the forfeiture of the license in the event of either unauthorized inactivity on the part of the developer or breach of the geothermal laws, regulation or license. The Model License mandates a reporting system and establishes an incentive system whereby the Minister of Energy undertakes to secure a number of investment incentives (for the most part preexistent in other legislation) for the licenses.

2. The Theory of Private Power Laws

Private development of public power resources is a relatively new innovation worldwide. The underlying rationale for introducing this approach into Kenya in 1990 deserves careful examination -- the theory underlying the law may determine not only the direction of future geothermal license/contract negotiations, but also whether the concept of private geothermal development is viable in Kenya.

There are two fundamental reasons for a country to promote private power development, project financing and lower rateholder costs.

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[9] Geothermal Resources Act, supra note 1, at § 8(2); Mining Act, Ch. 306, Laws of Kenya.

[10] Geothermal Resources Regulations First Schedule Model Geothermal Resources License § 3(1). The Geothermal Resources Regulations provide that a geothermal resources license

> ... may be accompanied by, or conditioned upon, the execution of a contract (to be known as a "geothermal resources contract") between the licensee and the relevant government departments or other body designated by the minister for the utilization of the geothermal resources.

* Private-sector financing is a viable alternative to public-sector financing in an era in which worldwide power demands will outstrip the availability of funds from traditional public-sector financial sources.

* Private-sector power projects, must be run on a cost-effective basis, producing the maximum possible power from available resources in the shortest possible time in order to be competitive and commercially viable. Thus, the successful private-sector project by its own internal, self-selection process will, in theory, generate lower-cost electricity for the benefit of the ratepayer.

Thus, the Kenyan legal, regulatory regime may properly be judged by the extent to which it creates incentives which will place the private power developer on equal footing with the public-sector developer of power. This issue is especially sensitive with respect to geothermal power. geothermal power, by its nature, is site specific. Unlike oil, it is not generally an exportable commodity. It has only one market -- the state utility monopolies. Therefore, the imposition of lease payments, royalties, customs duties and taxes will be passed along through the utility to the ratepayers. If a government does not levy such charges against the public-sector power developer, but does levy them against the private-sector developer, the private-sector developer is forced to absorb an unequal burden. At the outset of a private project these charges must be met by debt and equity contributions. Subsequently they must be met from operating revenues. In turn, repayment of principle and interest as well as on-going government charges must be met by the utility. Moreover, risk capital or equity must have a predictable return at least as high as investment in a industrial-nation banks Certificates of Deposit plus, an upside commensurate with the investment risk, if equity investment is to be attracted.

Consequently, a private-sector geothermal power development project cannot be compared with, or regulated as though it were, an industrial project or a mineral-development project. To do so ignores the fact that the nation is properly promoting both an alternative financing mechanism supplementary to public financing and a low-cost rate to the ratepayer.

On the other hand, the Government of Kenya holds geothermal resources in trust for all the people of Kenya. To the extent that it provides resource rights, land use, and incentives, it is providing quantifiable things of value. Thus, the people of Kenya are making an investment in private-sector power development in the same way that banks and private investors are making an investment. A fair and equitable method of repayment of the Kenyan investment must be built into any legislative and regulatory scheme.

The Build, Own, Operate and Transfer or "BOOT" model is one such method. In the BOOT model, the private-sector developer furnishes 100% of the financing. After the private-sector developer repays its debt burden and makes a reasonable return on its investment, by pre-agreement, the assets of the project are transferred to the Government for integration into its power production system. The fewer Government charges against income levied on the project during its private-sector phase, the sooner the transfer. One variation on this approach is to vest ownership of the project in the Government on an on-going basis. For example, a percentage of the corporation can be transferred to the Government by transferring stock ownership in lieu of royalties and lease payments. Thereby, from project initiation, the Government can participate in profits on a coequal basis with the other equity investors.

B. THE PRIVATE SECTOR PERSPECTIVE

From the perspective of a private-sector, transnational developer, the legal requirements prerequisite to undertaking steam and power production in a foreign country are relatively straightforward. The private-sector developer must:

(1) be assured of its right to the resources,

(2) be assured of its right to sell steam or electricity, and

(3) be assured of its right to earn and repatriate income sufficient to meet debt burden as well as to make a reasonable return on investment.

Knowledgeable financial experts have amplified on these three basic preconditions. They have stated that, as a general rule before governments and prospective private sponsors embark on private-sector energy projects, three conditions must exist: First, the host government must be firmly committed to putting the responsibility for the creation and operation of the new generating capacity into the hands of the private sector. Second, the host government must understand private-sector incentive mechanisms and be realistic in its risk-reward sharing expectations. And, third, the host government must be seen by the project sponsors and lenders to have a credible commitment to concluding a deal.[11]

Thus, even the relatively simple prerequisites of the private-sector power developer, must be understood and evaluated in the more sophisticated context of international financial imperatives. In this light, the following discussion examines the issues of the general agreement framework, resource rights, power purchase arrangements, and (D) economic incentives.

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[11] See, e.g., Stevenson, William A., "The Turkish BOT Power Experience," U.S.A.I.D. Report No. 89-04, Summary Report of the Philippine Seminar and Round Table on Private Power Generation through Build-Operate-Transfer (BOT), (May 1989).

C. THE GENERAL AGREEMENT FRAMEWORK

The Geothermal Resources Regulations, 1990, contemplate that a private-sector geothermal power project will be defined by a geothermal resources license into which will be incorporated a geothermal resources contract.[12] The Regulations appear to contemplate a single omnibus agreement, although there is no statutory or regulatory prohibition against dividing the agreement into sub-agreements in order to handle discrete issues more manageably. These sub-agreements may be incorporated into the geothermal resource contracts by reference. Agreement-management will depend greatly upon the parties to the agreement. If the power purchase agreement is between a private-sector developer and the utility, such a prerequisite agreement might be better negotiated separately and incorporated by reference into the Government's geothermal resources contract. Moreover, if it is determined to establish private/public joint ventures, such joint venture arrangements might also be separately negotiated.

The Power Purchase Agreements set forth below, plus any joint venture agreements, will form the core of a private-sector investment in a geothermal power plant in Kenya. However, depending upon circumstances, the parties may find that other agreements are useful in memorializing their intentions. This section describes some of the agreements which may be executed separately, or folded into a single, omnibus agreement.[13]

As discussed in Section II D below, in view of the unique public nature of a private-sector power project, it may be in the long term interests of all parties to have the geothermal resources contract package approved and passed into law by Parliament.

1. Preliminary Agreements

Depending upon the circumstances, a number of preliminary agreements may be executed.

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[12] Geothermal Resources Regulations, supra note 4, at § 3(1)(2).

[13] Id. at § 3(2) provides that a geothermal resources contract between the licensee and the government may accompany the Geothermal Resources License. Thus, such an omnibus agreement is authorized. This section and those following provide examples of the content of such an agreement. Id. supra note 4, at § 14(1).

a. Non-Disclosure Agreement

A non-disclosure or confidentiality agreement may be executed to preserve the integrity and confidentiality of information disclosed among joint venturers and to establish a schedule, a team and a procedure for pursuing further agreement. This concept is consistent with the Kenyan regulations. The Kenya Geothermal Resources Regulation, § 14(1) provides that "all information supplied to the [Minister of Energy] by the licensee shall be kept confidential and shall not be disclosed except with the consent of the licensee."[14]

b. Letter of Intent of Memorandum of Understanding

Memorandum of Understanding ("MOU") and letters of intent identify the parties engaging in the negotiations and, in general terms, the objectives which they seek to achieve. The objectives covered should include the type of entity to be created and what its function will be. It should include a stipulation of the intended level of capitalization for the new entity as well as the anticipated percentages of ownership and control to be assumed by the parties. It should address the intention of the parties as to the agreements which will form the geothermal resources contract (e.g., geothermal lease, power purchase, joint venture, construction, management, operations, etc.).

Comment

At this early stage of negotiations, the parties are often not far enough along to address specifics, nevertheless it is useful if significant provisions can be addressed.

A memorandum of understanding should identify the general responsibilities of each party during the start-up phase of the project, and should address a schedule by which certain procedures and acts should be complete in order to get the venture completed by a specific date.

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[14] This regulatory provision provides the Government the authority requisite to enter into a non-disclosure agreement with its joint venture partners.

2. Private-Sector Power Agreements

a. Geothermal Resources Agreement

The Geothermal Resources License envisioned by Kenya establishes the relationship between the government and the joint venture corporation or individual foreign corporation. The mineral lease issues associated with Geothermal Resources License are discussed in detail in section II B, below.

b. Joint Venture Agreement

The Joint Venture Agreement establishes the relationships among the private offshore developer, the public and private domestic partners and with the Government itself. The prevailing form is the equity joint venture agreement. In an equity joint venture, a new entity such as a corporation or a partnership is created specifically to achieve the joint venture objectives. The corporation format frequently used for international joint ventures. If no joint venture is contemplated the offshore developer will typically retain its domicile. If a joint venture with a private domestic corporation is contemplated, a neutral situs or the host country situs is common. In joint ventures with governmental entities, incorporation in the host country is generally mandated.

c. Construction, Operation and Maintenance Agreement

The construction, operation and maintenance agreement may be incorporated into the omnibus geothermal resources contract or may be addressed in the form of a separate agreement.

Assuming that the joint venture is, for example, between the offshore developer and a wholly government-owned entity such as the Kenya Power Company or a partially government-owned entity like Kenya Power and Light Company,[15] the joint entity is placed in a situation in one of its principals--the U.S. investor--will function as prime contractor for construction and subsequent operation and maintenance of the facility. It would appear prudent from the perspective of all parties to negotiate the construction, operation, and maintenance agreement in context of, and simultaneously with, the geothermal resources contract in order to ensure internal consistency.

In a joint venture arrangement in which the contractor is an equity participant, the tendency of the contractor will be to ensure an adequate return on investment through management/operating payments, payable off the top from gross income rather than through profits shared by the host investor.

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15 See text at section II C, below.

It is to the investor's interest to ensure that whatever formula is agreed--"costs plus percentage costs," guaranteed maximum, incentive contracts with mixed lump sum/cost plus--the host country owner (especially if it is a government) perceives that an equitable method of ensuring its fair share of income is formulated.

d. Power Sales Agreement

The electricity buyer and seller must have well-defined power contracts stating the amount, reliability and length of time (i.e., months, downtime, and time of day) that the energy producers will supply electricity. The Power Sales Agreement is discussed in detail in § II C below. Kenya has had no need to institute the complex regulatory regime as exists, for example for regulated utilities in the United States. Thus, a power sales agreement with KPLC is likely to be among the first of its kind. Therefore, this agreement may be free of certain regulatory constraints and may be drafted and negotiated as if the agreement were between two wholly-private entities. Offshore developers, however, are cautioned to ensure that their Kenya project activities are in compliance with the laws of their domicile.

3. Ancillary Agreements

Ancillary agreements may be useful to:

* implement, on a more detailed basis, the transfer of information, technical skill and equipment;

* protect the transferred information, equipment and technical data; and

* distribute responsibilities of the parties.

a. Examples of Ancillary Agreements

The list of ancillary agreement may include:

(1) an administrative services agreement,

(2) a supply agreement,

(3) a purchase agreement relating to equipment and machinery,

(4) an agreement related to indirect issues, e.g. the use or upkeep of the transmission and distribution system,

(5) an employee training agreement, and

(6) a technical assistance and licensing agreement.

b. Recourse/NonRecourse Agreements

In certain circumstances, especially those in which the transnational joint venture company arranges for host country financing, recourse and non-recourse financial agreements may be included in the package.

D. RESOURCE RIGHTS

The international private-sector geothermal developer is accustomed to entering into geothermal leases which typically permit the exclusive and discretionary right to explore and develop the leasehold and to erect commercial facilities in exchange for rent or royalty payments. The term of the lease is long enough to allow development and is automatically extended if the lessee is successful. The lease is short enough to allow reversion to the lessor in the event the lessee is inactive or unsuccessful. In Kenya, the geothermal resources license contemplates many of the issues traditionally covered by a geothermal lease. Nevertheless, some legal authorities might argue that the authority to use land pursuant to license is not perfected until a written lease is passed from lessor to lessee. In the final analysis, it is the financial investor or lender who must be comfortable that its investment is secure. The five following operative provisions are standard in geothermal leases, and may serve as a point of departure for a Kenyan formulation. They also illustrate the norms by which the land-use sections of the Kenya regulatory scheme may be evaluated by the international private sector developer.

EXAMPLE GEOTHERMAL LEASE

1. **EXCLUSIVE DEVELOPMENT RIGHTS.** The Lessee shall have the sole and exclusive right to explore for, drill for, produce, extract, remove, store, utilize, treat, process, convert and sell, geothermal steam, hot water, and related products during the term of the lease and any extension thereof. The rights of the Lessee in such uses shall include the right to construct, use and maintain a power-generating facility, roads, pipelines, utility and power lines and other structures and improvements which may be necessary or convenient in the operations under the lease.

2. **CONSIDERATION.** The consideration paid by the Lessee shall be [one or more) of the following:

a. Annual rental in the amount of per acre [or hectare] for the entire land area of the leasehold estate;

b. Royalty of percent of the proceeds from the sale by Lessee of geothermal resources, less any taxes imposed on the sale of such geothermal resources and less the cost to Lessee of any transmission to the point of sale.

3. **COMMERCIAL DEVELOPMENT.** At such time as Lessee shall have drilled and completed wells within the leasehold which shall indicate to the satisfaction of the Lessee a sufficient commercial potential, and at such time as the Lessee has obtained a market for the geothermal resources, Lessee may construct facilities for the commercial sale of products from the leasehold.

4. **TERM.** The lease shall remain in force for a period of years and thereafter so long as geothermal resources are produced or the Lessee is engaged in drilling operations or the construction of facilities for the commercial sale of products.

5. **DISCRETION.** The Lessee shall conduct its operations with reasonable diligence, but shall have no obligation to explore for, develop or produce geothermal resources for the leased land.

The approach which Kenya proposes to use is set forth in the Model Geothermal Resources License.[16]

(1) The License grants a Licensee (the lessee) broadly stated exclusive rights to explore for, extract and utilize geothermal resources for a term of thirty years.[17]

(2) Consideration is a yearly advance rental per hectare plus a royalty of a negotiated percentage of the value of each kilowatt hour.[18]

(3) This license requires the Licensee actively to develop the geothermal field or be subjected to forfeiting its rights.[19]

In its basic conceptual approach, the Model Geothermal Resources License is consistent with international geothermal resource standards. The deviations from industrialized country norms appear justifiable.

COMMENT

Pursuant to the terms of the Model License, if the licensee ceases work for six months, it may lose its license unless the previous written consent of the minister is obtained. It is common for developing countries to require an expenditure commitment or an obligation to drill. The penalty levied by the government of Kenya--forfeiture of the license in the event of inactivity by the Licensee--is not necessarily an onerous penalty to be imposed by a government charged

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[16] First Schedule, Model Geothermal Resources License, The Geothermal Resources Act, 1982 (No. 12 of 1982) and the Geothermal Resources Regulations, 1990, Kenya Gazette, Supp. 33, 269-276 (May 25, 1990) (hereinafter "Model License").

[17] Id. § 1-2. The thirty-year term is renewable for two further periods of five years each.

[18] Id. § 3.

[19] Id. Section 7(1). "The Minister may, by notice to the Licensee, declare this licensee to be forfeited [inter alia] if the licensee wholly ceases work in or under the license and during a continuous period of six months, without the written consent of the Minister."

with developing electrical resources for its people, provided that administrative authorization for delay caused, for example, by business contingencies is not unreasonably withheld. There may be some justifiable criticism of the six-month provision. Considering the delays endemic to international transactions, grace period may be unreasonably short.

Regarding consideration, the advance yearly rental plus a production royalty is straightforward. The Government should be aware that in higher risk exploration areas, it is customary for the lessor to waive or reduce initial rental fees until the area proves commercially productive--thereby encouraging exploration of unexplored sites. The Government might also consider crediting or applying rentals paid to the Government to royalties payable (or to become payable) on actual production. The key to successful cooperative development of energy resources by the private sector is elimination of penalties to risk taking--i.e., economic incentives.

The Model License does not specifically allow a deduction from royalty payments of any taxes. This omission might be perceived by investors as a loophole allowing the Government unilaterally to raise the amount of royalty payments by exercising its powers to tax. Such perceptions should be addressed by the Government, by contract or regulation. Otherwise, silence on the subject may frustrate the ability of developers to raise loan and equity contributions.

E. POWER PURCHASE

For private-sector power generation to be attractive as an investment to the private sector, certain economic and contractual requirements are necessary to increase investor benefits and thereby encourage development with the resultant public-sector benefits. From the private-sector developer's perspective, it will need a firm, power-purchase contract with the concomitant guaranteed electricity prices and reasonable guarantees of payment, investment security and system integrity.

It is useful to examine an outline of a standard power purchase agreement (the international norm) in context of the legal framework in Kenya.

EXAMPLE GEOTHERMAL PURCHASE AGREEMENT

1. OVERVIEW

1.1 **BASIC AGREEMENT.** The basic document is a single contract between a Company and a Utility where the Company contracts to design, build and operate for 24 hours a day, "x" days a year for "y" years, a facility producing "z" megawatts.

COMMENT

* It is presently contemplated that the Company would be majority owned by the off-shore investor, in a joint venture arrangement with one or more Kenya-governmental entities could be Kenya Power Company (KPC) or Kenya Power and Light Company (KPLC). KPC is a 100% government-owned company responsible for ongoing development of geothermal resources. It owns, **inter alia**, the Olkaria geothermal plant and associated transmission lines. KPLC has majority government ownership and control, but also has approximately 30% private ownership. KPC and the other government-owned companies which own generating stations have agreements with KPLC vesting responsibility for operations and maintenance of the power facilities with KPLC. KPLC thus functions as the sole power utility in Kenya. It is also recognized that KPC and KPLC have identity of management and staff. KPC is a paper company which KPLC personnel staff.

* The prospective private-sector investor and the Government of Kenya (including KPC and KPLC) will need to analyze the relative merits of identifying KPC and/or KPLC as a joint venture partner. The following analysis identifies the issues which may be identified by a hypothetical private-sector investor. The actual conclusions may differ, but this analysis is illustrative of the approach.

  Under the circumstances set forth the above, the private-sector investor may conclude that there is very little functional difference whether the Kenyan partner is KPC or KPLC. It is arguable that KPC (as a 100% government-owned entity charged with geothermal development) may enjoy the greater stability of the two and that there is less of a potential for conflict of interest if the utility is not in a posture of contracting a geothermal resources agreement with itself. On the other hand, one could argue with equal force that it is relatively easy to penetrate the corporate veil and that the two entities are indistinguishable.

From the perspective of the private-sector partner, the determining factor is which of the two entities establish sufficient credibility in the eyes of the international investment community to attract the requisite debt and equity capital. It is probable that both public and private foreign, lending institutions will require majority ownership and control to be in the hands of their own nationals and that as much of the host country ownership as possible be in the hands of the Kenyan private sector. This predisposition, coupled with the established operational track record of KPLC, argues that, on balance, KPLC may prove the most likely Kenyan partner.

The private-sector investor will have to ensure that the articles of incorporation and by laws of the Kenyan joint venture partner as well as the laws and regulations governing the operations of those entities allow them to enter a joint venture with a foreign partner.

* A joint venture agreement between the partners will be one element of the agreement package.

* The Kenyan joint venture partner will be in the best position to assume responsibility for obtaining all requisite Government approvals.

1.2. **MAJOR DEFINITIONS.** The following summarizes the key definitions:

"Agreement" means this Geothermal Resources Power Purchase Agreement.

"Annual Period" means any one of a succession of consecutive 12-month periods.

"Buyer" means Kenya Power and Light company (or "KPLC)".

"Buyer's System" or "System" means the Buyer's electrical system serving Kenya, including Buyer's Electrical Interconnection Facilities, beginning at the Point(s) of Delivery.

"Date of Initial Commercial Service" means the day the Seller designates as the initial date of production of electricity by Seller at its Facility.

"Electrical Interconnection Facilities" means those facilities required for the receipt or delivery of Electricity or any Point(s) of Delivery required to connect Buyer's System to the Facility in order to effectuate the purposes of this Agreement.

"Electricity" means the total amount of electricity producible by the Facility and available for sale.

"Force Majeure" a force such as (i) acts of God; (ii) war, insurrection, riot, civil disorder or disturbance; (iii) impact of national emergency; (iv) defaults of subcontractors and suppliers; (v) change of law; and (vi) strikes.

"Geothermal Resources License" means the Geothermal Resources License granted the ____ day of 19___, by the Minister of Energy to Seller.

"Joint Venture Agreement" means the agreement entered between and among ______________________________.

"kWh" means kilowatts of electricity per hour.

"kW" means kilowatts of electricity.

"Points of Delivery" means any points where the Seller's Electrical Interconnection Facilities connect to the Buyer's Electrical Interconnection Facilities.

"Seller" means the joint venture entity producing electrical power.

COMMENT

* These definitions are illustrative only.

2. **TERM.** Thirty years (plus two extensions of five years each).

COMMENT

* The terms of sale to the grid must be incorporated into the contract. To the extent that it is contemplated that the facility be transferred back to Government ownership--a build, own, operate, transfer or "BOOT" arrangement, a formula may be devised whereby, after the debt is paid and the Company receives an agreed return on investment, the facility may be transferred for an agreed sum. If the Government wants to expedite transfer, it will offer incentives to allow high retention of gross income (perhaps forfeiting royalty and thereby vesting itself with an increasing share of the corporate ownership), and be prepared to buy out of the Company early. If the Government wishes to minimize cash outlay, a long term contract, such as that apparently envisioned by Kenya, can usually allow transfer for a token sum of money.

3. **SALE OF ELECTRICITY**

3.1 Seller shall sell and Buyer shall buy all Electricity to be produced by Seller's facility.

3.2 **MONTHLY ELECTRICITY CHARGE.** Buyer shall pay Seller, in United States Dollars, a monthly electricity charge equal to (i) the capacity charge, calculated on a kW basis, plus (ii) the product of the energy price for the applicable calendar year, and the monthly quantity of Electricity on a kWh basis.

COMMENT

* This approach is illustrative. There are a number of formula which have proven effective. The economics of the project and the goals of the parties should dictate a result which can be expressed by formula.

* The kW basis and the energy price for the calendar year are at the heart of the agreement and therefore the subject of negotiations and formula set forth in separate appendixes.

  All parties must agree upon an electricity pricing formula which guarantees prices to the Seller. This formula should account for various factors such as system reliability, production costs to the private sector producer, avoided costs to the Buyer for oil, coal, natural gas, hydropower, etc., and generation capability. If reliable power is supplied by the Seller, the full avoided costs (energy plus capacity costs) are part of the criteria for selling the electricity transfer price which is also moderated by system reliability and capacity. From an economic perspective, avoided costs should reflect incremental or long run marginal costs of electricity production. These are the costs to the Seller for installing and operating the least-cost option.

* Hard currency payment is essential. Financial institutions will not loan the private sector project funds without hard currency repayment.

  Furthermore, since infrastructure projects such as power production facilities do not generate hard currency, financial institutions may require Government guarantees. In some of the developing countries, the Government guarantees only the power-purchase payments; it does not necessarily guarantee the loan. Should Kenya opt for this approach, the Government would only guarantee that payments will be made for the electricity it receives, not for the debt of a facility whether it succeeds or not.

4. **DUTIES OF THE PARTIES**

   4.1 **SELLER.** Seller shall obtain all material government approvals. Seller shall own, operate and maintain all Electrical Interconnection Facilities necessary for the delivery of electricity from its Facility to the Points of Delivery. Seller shall endeavor to provide uninterrupted delivery of Electricity to Buyer's System.

   4.2 **BUYER.** Buyer shall own, operate and maintain all Electrical Interconnection Facilities necessary for the receipt of electricity from Points of Delivery to its System. Buyer shall purchase Electricity.

5. **MEASUREMENT, METERING AND OPERATING SCHEDULE**

   5.1 **UNITS OF MEASUREMENT.** For the purposes of this Agreement Electricity shall be measured in kW and kWh.

   5.2 **MEASUREMENT EQUIPMENT.** Seller and Buyer shall each maintain electrical measuring, equipment. Seller's meters shall be used for quantity measurements. Testing, corrections of measuring equipment and maintenance shall be as mutually agreed.

5.3 **OPERATING SCHEDULE.** Seller and Buyer shall keep each other informed as to the operating schedule and condition of their respective facilities and equipment.

COMMENT

* Measurement provisions, with the requisite checks and balances must be carefully honed. Confidence of Seller and Buyer in the measurements must be scrupulously maintained if the Agreement is to be effective during the operating years. This issue, if not set forth with specificity at the outset of the relationship, may prove to be a major cause of friction in the relationship.

6. **BILLINGS AND RECORDS**

6.1 **MONTHLY BILL TO BUYER.** Seller shall bill Buyer for the amount of Electricity actually delivered by Seller during the preceding month.

6.2 **PAYMENT.** Buyer shall pay Seller in U.S. dollars for all amounts billed pursuant to Article 6.1 within thirty (30) days of the receipt of Seller's Statement.

6.3 **RECORDS.** Both Seller and Buyer shall maintain such records as mutually agreed which shall be available for inspection by either Party upon reasonable notice.

COMMENT

* Certainty of payment underlies project financing. Interest penalties for late payment are normally part of these provisions.

7. **TAXES.** Seller shall be solely responsible for any income taxes relating to the Facility. Buyer shall be solely responsible for any sales, use, property, income or other taxes relating to the Buyer's System, as well as any taxes imposed on the sale to the Buyer of Electricity produced by the Facility.

8. **REPRESENTATIONS AND WARRANTIES**

8.1 **REPRESENTATIONS AND WARRANTIES OF BUYER.** Buyer hereby represents and warrants to Seller as follows:

A. Buyer is a corporation duly organized and existing in good standing under the laws of Kenya and is duly qualified to do business in Kenya.

B. Buyer possesses all requisite power, authority, including regulatory authorities and financial capability, to enter into and perform this Agreement and to carry out the transactions contemplated hereunder.

8.2 **REPRESENTATIONS AND WARRANTIES OF SELLER.** Seller hereby represents and warrants to Buyer as follows:

A. Seller is a joint venture duly organized and existing under the laws of and is duly qualified to do business in Kenya.

B. Seller possesses all requisite power and authority to enter into and perform this Agreement and carry out the transactions contemplated hereunder.

COMMENT

* In most international transactions, particularly where there is a direct foreign investment of the type contemplated here, an initial decision to be made concerns the type and nationality of the entity which will actually engage in the activity.

  Factors which are usually considered in making such selection include foreign and domestic taxation, methods of financing the operation, credit risks and concerns, trade incentives, risks concerning injury to person and property, local licensing and permitting public relations, etc.

* There is no requirement under the Geothermal Resources Act and its implementing regulations that the Licensee be a Kenya corporation. The contemplated joint venture, however, would be with KPC or KPLC. Whether either of those corporations are permitted (i) to enter into a joint venture with a foreign company (in a partnership-type joint venture), or (ii) to become shareholders in a foreign company (by forming a new corporation with an offshore situs), is a question which needs to be examined. On such examination, it is probable that the joint venture Seller must have a Kenya situs by virtue of the KPC or KPLC tie-in.

  If a Kenya situs for the joint venture is selected the Government must assure the joint venture that it may continue to take advantage of the economic incentives established by the License. For example, Article 17(2) of the Model Geothermal Resources License mandates that the Licensee appoint an attorney resident in Kenya to supervise operations under the license.[20] Clearly, this and similar such provisions contemplate an off-shore, foreign Licensee. Consequently, one of the incentives to the Licensee, for example contained in Article 16(1)(e) of the Model License, is the ability freely to repatriate abroad all proceeds from the Licensee's geothermal operations, including the proceeds from power sales. If a Kenya situs is elected for the venture, the Model License will have to be carefully drafted to recognize and to accommodate the fact that the Licensee is in part foreign, in part domestic.

In the event of mixed foreign/domestic ownership, the provisions of the License should conform its legal language so that the spirit of the incentives remains intact and expresses the intent of the Ministry.

9. **INDEMNIFICATION.** Each Party agrees to protect, indemnify and hold harmless the other Party and its directors, officers, shareholders, employees, agents and representatives against any and all loss on account of injury to persons, or for damage to property arising out of that Party's operation of facilities, except if such injury or harm is caused by the negligence of the other Party.

10. **INSURANCE.** The Buyer and the Seller shall each obtain and maintain in force comprehensive general liability insurance in agreed amounts.

11. **ARBITRATION.** Arbitration shall be under the Convention for the Settlement of Investment Disputes between States and Nationals of Other States.

COMMENT

* Most private-sector investors consider it of particular importance in contracts with government entities to specify clearly what jurisdiction's laws will be applied in the interpretation and enforcement of the contract, to specify where disputes will be resolved and how disputes will be resolved (arbitration is the generally preferred method). Each party to the Agreement will normally want the laws of its own domicile to apply and

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[20] This requirement is probably inserted to ensure an adequate nexus between a foreign-owned corporation and Kenya.

for the dispute to be settled by a tribunal located in its domicile.

* In electing an arbitral tribunal, special care should be taken to ensure that Kenya has officially recognized that forum. The following list sets forth the major arbitral tribunals.

a. **ICSID.** The Convention on the Settlement of Investment Disputes between States and Nationals of other States ("ICSID") establishes the International Center for Investment Disputes. This convention has the unique advantage of providing that each contracting state shall recognize and enforce an ICSID award as though it were a final judgment of the country's courts. ICSID is limited to disputes arising between a state party to the convention and a national of another state and must arise from an investment dispute. Kenya is a member of ICSID, and contemplates the use of ICSID in the Model License.

b. **The New York Convention.** The 1958 United Nations Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the "New York Convention"), ratified by approximately 70 countries, provides that an international award rendered in a country party to the Convention may be enforced in another convention country.

c. **UNCITRAL.** This model set of rules was unanimously approved by the U.N. They are of particular interest because arbitrations administered by the London Court of Arbitration and The American Arbitration Association can be carried out using these rules.

d. **ICC.** The International Chamber of Commerce rules have the advantage of being internationally recognized (unlike those of the American Arbitration Association).

e. **AAA.** The American Arbitration Association rules are perhaps more effective than others, provided that the contracting parties are citizens of countries which have ratified the New York Convention, as its procedures generally involve less delay and expense.

12. **BREACH OF CONTRACT.** This provision sets forth the events which are deemed to create a breach of contract and the remedies for such breach.

COMMENT

* Liabilities such as penalties for default on contracts are important to the utility (KPLC) vis-a-vis future

expansion plans.

* Of overriding importance are the breach of contracts envisioned under the Kenya regulatory scheme. Since a breach results in forfeiture of rights, the Government will have enormous leverage over the joint venture seller.

13. **MISCELLANEOUS.** These provisions addresses notice, service successors and assigns, third party beneficiaries, confidentiality governing law, language, currency, effective date, amendments and other such significant issues.

D. ECONOMIC INCENTIVES

The private-sector investor in a Kenya geothermal power plant will take a careful look at of the institutional and legal framework in making a determination as to whether to invest in Kenya. The income produced by electricity sales is only one component of the analysis. For example, to the transnational sector investor, time is money. The time eaten up by inordinate government administration may be the difference between profit and loss, and is often a key element in deciding whether to place risk capital in a given country. This section will define its subject "economic incentives" in the broadest possible meaning of the term and examine the multitude of interrelated issues from the legal perspective which, in sum total, constitute the Kenya economic incentive package.

F. INVESTMENT LAWS AND CODES

1. Overview

In general, in order to regulate foreign investment and joint ventures on their territories, most countries have enacted "investment laws" or "investment codes" whose purpose is to create a legal framework for the entry and operation of foreign capital. Some countries have enacted a network of laws rather than a general investment law which, though complex, serves the same purpose. Few countries view a foreign investment project, _in_ _and_ _of_ _itself_, as a good thing. A foreign investment project is desirable if it has desirable effects on the host country's economy. Every project will have both benefits as well as costs and risks. A geothermal power project will have both. Therefore, Kenya may view a private-sector geothermal power facility as a mixed blessing with costs as well as benefits. Consequently, the objective is to strive for agreements which will structure such a facility project so as to maximize benefits and minimize the costs to both sides. However, as has been discussed, in § I.B above, a private infrastructure project has a unique public element, and incentives designed for the proverbial "widget manufacturer" need to be evaluated with their application to a private-sector power project.

2. The Investment Laws and Regulations of Kenya

Since Kenya achieved independence in 1963, the Kenyan government has pursued a policy of creating a mixed economy in which the public and private sectors play a role.

a. Constitution

The Constitution of Kenya establishes fundamental due process protection from the deprivation of private property:

> No property of any description shall be compulsorily taken possession of, and no interest in or right over property of any description shall be compulsorily acquired ... unless provision is made by a law applicable to that taking of possession or acquisition for the prompt payment of full compensation.[21]

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21 Kenya Constitution, Art. 75, para. (1). Full text appears in Appendix VIII.

COMMENT

This provision in the Kenya constitution is similar to standard provisions in most investment laws which make guarantees, in varying degrees, against nationalization or expropriation. Such language, although extremely significant, may be viewed by the international financial community (which has witnessed abuses) as being of limited usefulness. However, in any eventual investment dispute resulting from expropriation, it may provide support for an adequate standard of compensation, e.g., "prompt, adequate and effective."

b. Investment Law

The primary investment law of Kenya is the Foreign Investments Protection Act.[22] The Foreign Investments Protection Act is a classic mix of checks and balances. It controls the formation and operation of investment while it simultaneously encourages foreign investment primarily by offering foreign investors and joint ventures a variety of incentives.

Under the Kenya statutory scheme, foreign investors may apply for and be granted certificates if it is determined that the enterprise would "further the economic development of, or would be of benefit to Kenya." Importantly, a certificate holder "notwithstanding the provisions of any other law for the time being in force," may transfer out of Kenya the approved foreign currency, at the prevailing official rate of exchange. This includes after tax profits, equity investment and the principal and interest of loans.[23]

COMMENT

* The language of the statute is clear that any investment variations must be certified, thus the private-sector investor must diligently update its certificate.

* Repatriation of foreign currency may be delayed (not stopped -- but delayed) by administrative processes, outside the statutory framework, This issue should be scrutinized by the prospective investor.

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22 The Foreign Investments Protection Act, Ch. 518 (Dec. 15, 1964) as revised by the Foreign Investment Protection (Amendment) Act, 1988, Kenya Gazette No, No. 50, 58-60 (Aug. 11, 1988). Full text appears in Appendix IX.

23 Id. § 3.

c. Investment Promotion Center

The Investment Promotion Center was created by the Government of Kenya under an Act of Parliament to serve as the primary contact point for companies and entrepreneurs, both local and foreign, wishing to explore investment opportunity in Kenya.[24] The Center functions to streamline application and approval procedures--"One Stop" shopping. According to the Center, "recent policy statements have indicated that the Government expects the private sector to play an increasingly important role in the provision of goods and services. Foreign investment is welcomed...."

COMMENT

> The Center is a relatively new government organization, Since installation of a private-sector power facility would represent the implementation of a major policy issue, the private-sector investor may find that the Center would augment investment efforts with the relevant government ministry and agencies, but would not relieve the investor of the primary burden of proceeding. As noted in the overview to this chapter, a geothermal power-production facility is more properly viewed as an integral part of the Government's power infrastructure than as an offshore developer of a Kenyan manufacturing facility.

d. Geothermal Investment

The Geothermal Resources Act and its implementing regulations represent a special investment law for the geothermal energy sector. The incentives are spelled out contractually in the Model Geothermal Resources License. These incentives (section numbers in parentheses) include:

(1) **Entry.** Facilitated entry permits for technicians and managers. (§ 14)

(2) **Import.** Facilitated permits for import relating to operations, exempt from all customs duties, and, when certified by a representative of the Ministry of Energy, waiver of approval of import license and

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[24] See Investors' Guide to Kenya, Vols. I to IV (May 1989). In President Moi's 1982 inaugural address, he stated, "... The private sector will in the future play an increasingly large role in development, through both domestic and foreign investment. The Government will do everything in its power to encourage both domestic and foreign investor."

waiver of exchange control approval. (§ 15(1)(2)(3))

(3) **Household Goods.** Facilitated permission for expatriate employees to import exempt from all customs duties. (§ 15(4))

(4) **Resale.** Licensee, contractors and expatriate employees may sell imported items no longer needed for operations. (§ 15(5))

(5) **Export.** Licensee, contractors and expatriate employees may export previously imported articles free of all export duties. (§ 15(6))

(6) **Foreign Bank Accounts.** Maintain external accounts inside Kenya, and foreign bank accounts outside Kenya.[25] (§ 16(1)(a))

(7) **External Disposition.** Receive and retain foreign currency outside Kenya. (§ 16(1)(8))

(8) **External Payments.** Pay directly outside Kenya for goods and services in Kenya. (§ 16(1)(c))

(9) **Payroll.** Pay expatriate employees in foreign currency outside Kenya. (§ 16(1)(d))

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[25] See Exchange Control Notice No. 3; Exchange Control Act CAP. 113 (1988).

(10) **Repatriation.** Fully repatriate abroad all proceeds from the licensee's geothermal operations in Kenya, including but not limited to proceeds from the sale of assets (i.e., Electricity). (§ 16(1)(e))

COMMENT

* Query. Would this provision expand on the repatriation provisions of the Foreign Investments Protection Act?

(11) **Most Favored Investor.** Rates of exchange would be not less favorable than those granted to any investor.

(12) **Central Bank Approval Waived.** Licensee could enter all contracts without prior approval of Central Bank (or any another Government agency), subject to giving preference to Kenyan goods. (§ 16(3))

(13) **Certification.** Facilitation of the obtaining of a Foreign Investment, Protection Act Certificate of Approved Enterprise (with the amount recognized by the certificate equalling the amount set forth in the Licensee's books of accounts). (§ 16(4))

COMMENT

* The Minister is excused of all contractual obligations in the event of force majeure--by definition, an occurrence beyond the reasonable control of the Minister which prevents performance of obligations.

  Consequently, the effective result is that the incentives set forth in the Model License represents a good faith, best efforts undertaking by the Minister, excusable in force majeure circumstances--disputes over which would be settled by reference to ICSID arbitration.

  * The term "force majeure" requires careful definition.

  * The certainty of the incentives set forth in the model License is somewhat diluted by the fact that the Minister cannot act ultra vires. Thus, a conflicting law or regulation might govern in the event of a conflict between the contractual license and such law or regulation. In view of long term nature of the license contemplated (30 to 40 years), it would seem to be in the interest of both parties for the agreed-on license to be enacted into law by the Parliament. There appears to be precedent for

such special legislation in Kenya which has been established by practice in the area of petroleum development contracts.

3. Investment Checklist

Most transnational corporations will ask a time-proven series of questions prior to making an investment. Many of these have been addressed elsewhere in this chapter. Where previously covered, this list provides a convenient summary. Where not otherwise covered, they provide a mechanism to identify and to address the issue.

a. Ground Rules. What are the host country procedures, customs and regulations regarding foreign exchange, customs, and insurance?

The model Geothermal Resources License provides a mechanism for "most favored investor" exchange rates; however, the issue of whether and how the utility, KPLC, will pay the power producer in hard currency is not addressed. The Model License waives the most onerous customs duties. The issue of whether KPLC will be able to obtain the insurance requisite under the power purchase agreement is unknown.

b. Import Restrictions. Will the venture be allowed to import or purchase necessary raw materials or components, or will there be prohibitively high tariffs?

The Model License resolves in the affirmative the question of whether the venture will be allowed to import or purchase components. Approved projects may obtain the privilege to import capital goods, spare parts at reduced tariff rates or without the payment of any customs duty at all. The issue of raw materials is not expressly addressed by the Kenya regulations, but may be a de minimus issue for the geothermal power producer. Due to high customs duties prevailing in Kenya, such customs exemptions are extremely important to the commercial feasibility of the project.

C. Financial Ability. What are the regulations affecting the ability of the joint venture to pay for imported goods, e.g., ability to use letters of credit and other forms of payment, availability of dollar funds located outside the importer's country? Does Kenya law establish financial criteria--such as guidelines for the amount of capitalization or funding to be made by a U.S. partner to a local business entity?

In general, the Model License allows a viable financial scheme. No legal regulations exist for participation by Kenya nationals in foreign-owned ventures. The government may use its economic power to provide various guarantees of foreign loan, guarantees from the central bank to provide hard currency for debt servicing, and guarantees by government agencies to purchase the surplus production at a minimum price, thereby assuring a certain degree of profitability.

d. Labor Law. Does Kenya law regulate the number of foreign nationals which may be employed? Does it regulate management or director appointments?

Minimum wages are prescribed by law and vary according to type of job and locality. They are increased periodically and published in the Kenya Gazette. In Nairobi, average wages paid in practice at the beginning of 1988 were about Ksh 800 per month for an unskilled worker and Ksh 1300 per month for a skilled worker. Overtime is paid at one and a half times the normal hourly rate, and at two times wages on holidays.

Legal maximum working hours are 52 in a six-day work week. However, in practice a 45 hour, six-day work week is generally observed. Employees are legally entitled to 24 days annual paid vacation after one year of continuous employment. There are a total of 11 paid public holidays during the year.

Total fringe benefits, include social security and health insurance, amount to about 30 percent of the basic wage. In practice, an employee is entitled to 60 days of sick leave per year: 30 days on full pay and 30 days on half pay. Women are entitled to maternity benefits for two calendar months, forfeiting annual paid vacation.

In normal circumstances, an employer must give one month's notice of termination. On actual termination, the employer must pay one month's wages in lieu of dismissal notice, any accrued holiday pay, and severance pay if the employee has worked for more than five years.

A number of trade unions are registered under the Trade Union Act. They are organized by craft, rather than industry, and belong to a central group, The Central Organization of Trade Unions (COTU). The modern sector work force is highly unionized. However, Kenya has a well developed system of industrial relations and labor relations are generally friendly. Union membership is not compulsory in any industry.

e. Incentives. What are the incentives to attract foreign investment including remittability of profits, interest, and royalties?

The major instrument of guarantees for foreign investments is the Foreign Investment Protection Act. Under the Act the Minister of Finance issues a certificate of Approved Enterprise to foreign nationals who invest in approved sectors in foreign currency or re-invest their retained earnings in Kenya. This allows investors to transfer:

* Profits, after tax, including retained profits which have not been capitalized

* The original equity investment, plus retained profits which have been capitalized

* Principal of foreign loans and interest as specified in the certificate

Capital gains arising from the sale of foreign assets not permitted to be transferred out of Kenya are required to be invested in Government Securities at market rates. The income from the Government Securities in which the capital gains are invested may be transferred out of Kenya when received. In addition, the capital gains may be repatriated at the end of five years in the same manner applicable to the original equity investment.

Kenya has not established a tax-benefit program to attract investors. Nearly all host countries manipulate their tax and fiscal systems in order to attract foreign investment. One of the most common incentive is the "tax holiday" which exempts the enterprise--and sometimes the investor--from local income and other taxation for a specified period of years. The host country may also grant exemptions from taxes on dividends, royalty payments, interest payments, property taxes and numerous other charges and fees for which the project, its investors, creditors, contractors, and subcontractors would otherwise be liable. A variation on the tax holiday is "tax stabilization" which guarantees that the approved project will pay no more than a specified maximum tax exemption or relief to the joint venture's foreign employees. Nonetheless, the issue of a tax holiday might be explored with the Kenya government.

In negotiating tax incentives, the investor should take great care to understand Kenya's tax system, especially how its tax laws are applied in practice, so that the incentive obtained will contribute a meaningful benefit. Moreover, it is important to determine precisely when the tax holiday begins. Ideally, in a semi-public infrastructure enterprise taxation should be delayed so that principle and interest payments may be met and, if possible, accelerated.

Rather than to grant outright tax exemptions, many countries achieve the same result--i.e., increasing after-tax cash flow--by allowing the project to take increased tax deductions for accelerated depreciation.

f. Organization of Businesses. Which local form of business association is best suited to a geothermal power operation? If under local law a joint venture is necessary, what are the standards to be applied in the selection of foreign partners, distribution of control and operations?

These questions are more contractual than legislative and need to be addressed in context of the prospective joint venture agreement.

g. **Corporation/Companies Law.** Does Kenya law prohibit the conduct of the relevant business activity by a business entity other than one created under the law of the host country? Does it require government approval of the relevant business?

Foreign investors need to apply for and obtain a Certificate of Approved Enterprise if they wish to avail guarantees provided under the Foreign Investment Protection Act. Other special licenses and approvals may be required for particular types of businesses. Employers must register with the tax authorities and the National Social Security Fund. Finally, plans for any buildings or other facilities of a permanent nature must be submitted to the concerned local authority for approval.

The principal forms of business enterprise in Kenya are:

* Limited Companies (private or public)
* Branches of a foreign company
* Partnerships
* Sole Proprietorships
* Cooperatives

Investors are advised to retain local legal counsel to carry out the steps necessary to establish a company in Kenya. Kenya's legal system is based on English law and practice. The Investment Promotion Center can provide a list of lawyers with experience in dealing with the legal and commercial aspects of investment, both foreign and local.

Foreigners who intend to work in Kenya are required to obtain work permits. Such work permits are issued by the Immigration Department, which is under the Office of the President. Work permits are generally issued for an initial period of two years. Work permits for top-level managers and technical personnel should be carefully agreed on in advance.

h. **Taxation.** What is the interrelationship of the tax laws of the domicile of the foreign investor and local taxation, including tax treaty implications and availability of foreign tax credit for foreign taxes paid?

o **Corporate Income Tax.** Locally registered and incorporated companies, both foreign and local, pay corporate tax at the rate of 45 percent of taxable income. Branches of foreign companies pay income tax at the rate of 52.5 percent, a corporate tax burden comparable to European levels. There are no provincial or municipal income taxes, but local authorities may levy property taxes. No other corporate income taxes or surtaxes exist.

Businesses which suffer losses can carry forward such assessed tax losses to be set off against subsequent taxable profits. Losses may be carried forward until adequate profits have accrued to absorb carried forward losses.

Personal Income Tax. Income tax is charged on the income earned in Kenya by any person resident in Kenya. A wife's income is assessed independently of the husband, and is taxed at the same rates as the husband. Expatriates working in regional offices located in Nairobi are exempted from income tax on one-third of their earnings if such earnings are paid from offshore sources. Expatriates employed in Kenya are allowed to remit in foreign currency part of their earnings.

Personal income tax rates are levied in the following manner:

Ksh	%
1-39,600	10
39,601-79,200	15
79,201-118,80	25
158,401-198,000	45
over 198,000	50

Housing, allowances, cars and other perquisites are imputed at specified rates and added on to taxable income. As long as these items continue to be d at less than 100% of the foreign joint-venture corporation may view these items as incentive benefits to its employees.

Sales and Withholding Taxes. Sales tax is levied on all manufactured goods produced in or imported into Kenya. The ad valorem rate is 17 percent on most goods, with higher rates levied on drinks, cigarettes and luxury items.

Withholding tax is deducted from payments of dividends, interest, royalties, and other unearned income to nonresidents. Rates of withholding tax (1990) are as follows:

Type of Payment	Withholding Rate (percentage)
Management/Professional Fees	20
Royalties	20
Rent	20
Dividends	15
Interest	12.5
Pensions and Annuities	5

o **Tax Treaties.** Comprehensive tax treaties are in force with Canada, Denmark, the Federal Republic of Germany, Malawi, Norway, Sweden, the United Kingdom, and Zambia. These tax treaties generally provide for avoidance of double taxation and reduce or waive the withholding taxes outlined above.

i. **Dispute Resolution.** What is the usefulness of arbitration agreements under local law, treaties and international rules? Does Kenya law require that disputes in regard to local activities be resolved in the courts of Kenya and governed by the laws of Kenya?

Kenya is a member of the International Center for Settlement of Investment Disputes, ICSID, and, thus, disputes may be settled exterior to the courts of Kenya. The applicable law appears to be a matter to be resolved by agreement.

j. **Ownership Law.** Who may own or use geothermal resources? How is access to the power grid regulated? Who owns the transmission lines? How and to what degree of efficiency are utility bills collected and to what extent is the utility subsidized?

The Government owns the geothermal resources, development authority rests with KPC, but KPLC is the monopoly utility.

The issue of efficient collection of utility bills will be at the heart of the power purchase agreement.

k. **Currency.** Does Kenya law regulate the repatriation of capital, the importation of foreign currency, or the rate at which the local currency may be converted into U.S. dollars upon repatriation of profits or other distributions to the United States? Does it regulate the economic return on the U.S. partner's investment which may be repatriated from one year to the next?

A Certificate of Approved Enterprise to foreign nationals who invest their retained earnings in Kenya this allows investors to transfer:

* Profits, after tax, including retained profits which have not been capitalized

* The original equity investment, plus retained profits which have been capitalized

* Principal of foreign loans and interest as specified in the certificate

Capital gains arising from the sale of foreign assets not permitted to be transferred out of Kenya are required to be invested in Government Securities at market rates. The income from the Government Securities in which the capital gains are invested may be transferred out of Kenya when received. In addition, the capital gains may be repatriated at the end of five years in the same manner applicable to the original equity investment.

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Methodology for Section III Sensitivity Analysis

Appendix I

Sensitivity Analysis:

In order to understand both the impact of various contingencies on the KPLC system and the prospective benefits of private geothermal development, we have done a common set of sensitivity analyses for each of the cases listed below. Cases refer to alternative forecast and oil price assumptions, with sensitivity analysis referring to analysis of various different capacity timing and cost assumptions. The sensitivity assumptions which are examined in each case below are as follows:

Sensitivity Number:	Description:
1.	KPLC Base Case
2.	KPLC Base Case, except that all geothermal additions are delayed by 1 year.
3.	Same as 2, except that 50 MW of private geothermal are added in 1994-95.
4.	Same as 2, except that 40 MW of private geothermal are added, 20 MW each, respectively, in 1993-94 and 1997-98.
5.	KPLC Base Case, Except that all geothermal additions are delayed by 2 years.
6.	Same as 5, except that 50 MW of private geothermal are added in 1995-96.
7.	Same as 5, except that 40 MW of private geothermal are added, 20 MW each, respectively, in 1995-96 and 1998-99.
8.	KPLC Hydro and Coal new capacity is delayed by 1 year in all instances.
9.	Same as 8, except that 50 MW of private geothermal are added in 1996-97.
10.	Same as 8, except that 40 MW of private geothermal are added, 20 MW each, respectively, in 1996-97 and 1997-98.
11.	KPLC Hydro and Coal new capacity is

delayed by 2 years in all instances.

12. Same as 11, except that 50 MW of private geothermal are added in 1996-97.

13. Same as 11, except that 40 MW of private geothermal are added, 20 MW each, respectively, in 1996-97 and 1998-98.

14. KPLC Base Case, except that all KPLC geothermal capital costs are increased by 25%.

15. Same as 14, except that 50 MW of private geothermal are added in 1994-95 as a substitute for 32 MW of KPLC geothermal.

Case 1 consists of the basic sensitivity results compared under KPLC base case assumptions on forecast growth (Table III-) and oil prices.

Case 2 consists of a set of sensitivities on a revised KPLC base case with a high forecast of load growth.

Case 3 again is a new set of sensitivities, this time with the original baseline forecast, but with oil price increasing more rapidly.

Case 4 shows the impact of sensitivities on a base case with both a high forecast and high oil prices.

Basic Assumptions for the different cases are as follows:

	Forecast Growth	Oil Prices Price Escalation	Base Increase
Case 1:	4%	4%	10%
Case 2:	6.7%	4%	10%
Case 3:	4%	6%	20%
Case 4:	6.7%	6%	20%

As noted above reserve margins realized varied considerably in the sensitivities, and in general showed significant reserve deficits in most cases, even when KPLC plans were realized as planned with the base case forecast. Furthermore, unserved energy became an extremely high figure in several of the sensitivities, particularly under the high forecast. This result perhaps even understates the potential danger, as it is assumed that the KPLC plan is realizable (except for the explicit sensitivity delays, etc.), and due to other contingencies not modeled such as drier than average years, failure to realize combustion turbine plans as expected, lower than expected energy or capacity from Turkwell, etc.

System Cost Scenario Results for Section III

Appendix II

Appendix II

System Cost Scenario Results for Section III

Case 1 - Base Case Forecast and Oil Price Escalation Rates

Case 1 Base Case/Forecast and Oil Price Escalation	Total Annual Capital Cost (000$)	Unserved Energy (000$)	Variable Costs (000$)	Total Costs (000$)	Change From Base (%)	Average Cost (000$)	Change From Base (%)
1 KPLC Base Case	$1,242,616	$0	$1,400,641	$2,643,257		$0.037	0.00%
2 KPLC Geothermal-1Yr Delay	$1,153,614	$4,510	$1,530,223	$2,688,347	1.71%	$0.037	2.36%
3 Geo. 1 Yr Delay+50MW Priv. Geo.	$1,314,606	$0	$1,289,432	$2,604,039	-1.48%	$0.036	-2.30%
4 Geo. 1 Yr Delay+2x20MW Priv. Geo.	$1,295,253	$0	$1,397,448	$2,692,701	1.87%	$0.037	1.77%
5 KPLC Geothermal-2Yr Delay	$1,081,846	$14,950	$1,655,863	$2,752,660	4.14%	$0.038	4.94%
6 Geo. 2 Yr Delay+50MW Priv. Geo.	$1,229,423	$4,510	$1,391,766	$2,625,698	-0.66%	$0.036	-0.63%
7 Geo. 2 Yr Delay+2x20MW Priv. Geo.	$1,236,975	$0	$1,421,591	$2,658,567	0.58%	$0.037	0.86%
8 KPLC Hydro & Coal-1Yr Delay	$1,156,234	$0	$1,520,251	$2,676,485	1.26%	$0.037	1.73%
9 Hydro & Coal Delay+50MW Priv. Geo	$1,290,395	$0	$1,304,665	$2,595,059	-1.82%	$0.036	-2.25%
10 Hydro & Coal Delay+2x20MW Priv. Geo	$1,284,384	$0	$1,363,675	$2,648,060	0.18%	$0.037	-0.01%
11 KPLC Hydro & Coal-2Yr Delay	$1,069,853	$0	$1,626,323	$2,696,176	2.00%	$0.038	2.93%
12 Hydro & Coal Delay+50MW Priv. Geo	$1,204,013	$0	$1,375,076	$2,579,089	-2.43%	$0.036	-2.30%
13 Hydro & Coal Delay+2x20MW Priv. Geo	$1,198,003	$0	$1,443,452	$2,641,455	-0.07%	$0.037	0.28%
14 KPLC Geothermal 25% Cost Rise	$1,373,546	$0	$1,400,641	$2,774,187	4.95%	$0.038	4.50%
15 KPLC Geo. Cost Rise+50MW Priv Geo	$1,384,061	$0	$1,331,595	$2,715,657	2.74%	$0.037	1.69%

Case 2 - High Forecast Demand Growth and Base Oil Price Escalation Rates

Case 2 Forecast High Case with Base Oil Prices	Total Annual Capital Cost (000$)	Unserved Energy (000$)	Variable Costs (000$)	Total Costs (000$)	Change From Base (%)	Average Cost (000$)	Change From Base (%)
1 KPLC Base Case	$1,242,616	$300,686	$2,351,668	$3,894,971		$0.044	19.41%
2 KPLC Geothermal-1Yr D	$1,153,614	$802,860	$2,638,176	$4,594,650	17.96%	$0.047	27.24%
3 Geo. 1 Yr Delay+50MW	$1,314,606	$211,131	$2,045,631	$3,571,369	-8.31%	$0.041	11.18%
4 Geo. 1 Yr Delay+2x20M	$1,295,253	$325,302	$2,222,511	$3,843,066	-1.33%	$0.043	17.18%
5 KPLC Geothermal-2Yr D	$1,081,846	$1,318,324	$2,870,163	$5,270,333	35.31%	$0.049	34.01%
6 Geo. 2 Yr Delay+50MW	$1,229,423	$528,038	$2,326,260	$4,083,721	4.85%	$0.044	18.93%
7 Geo. 2 Yr Delay+2x20M	$1,236,975	$538,275	$2,415,584	$4,190,835	7.60%	$0.045	21.74%
8 KPLC Hydro & Coal-1Yr	$1,156,234	$748,742	$2,612,131	$4,517,108	15.97%	$0.046	26.16%
9 Hydro & Coal Delay+50	$1,290,395	$137,604	$2,116,870	$3,544,869	-8.99%	$0.041	13.42%
10 Hydro & Coal Delay+2x	$1,284,384	$188,850	$2,235,379	$3,708,614	-4.78%	$0.043	17.17%
11 KPLC Hydro & Coal-2Yr	$1,069,853	$1,602,542	$2,872,594	$5,544,989	42.36%	$0.049	33.80%
12 Hydro & Coal Delay+50	$1,204,013	$359,437	$2,377,333	$3,940,783	1.18%	$0.044	19.07%
13 Hydro & Coal Delay+2x	$1,198,003	$513,175	$2,495,842	$4,207,020	8.01%	$0.045	23.09%
14 KPLC Geothermal 25% C	$1,373,546	$300,686	$2,351,668	$4,025,901	3.36%	$0.045	23.34%
15 KPLC Geo. Cost Rise+5	$1,384,061	$122,566	$2,145,712	$3,652,339	-6.23%	$0.043	16.42%

<u>System Cost Scenario Results for Section III (Continued)</u>

Case 3 - Base Case Forecast and High Oil Price Escalation Rates

Case 3 High Oil Price Growth With Base Forecast	Total Annual Capital Cost (000$)	Unserved Energy (000$)	Variable Costs (000$)	Total Costs (000$)	Change From Base (%)	Average Cost (000$)	Change From Base (%)
1 KPLC Base Case	$1,242,616	$0	$1,746,390	$2,989,006		$0.042	14.34%
2 KPLC Geothermal-1Yr Delay	$1,153,614	$4,510	$1,915,997	$3,074,121	2.85%	$0.043	18.43%
3 Geo. 1 Yr Delay+50MW Priv. Geo.	$1,314,606	$0	$1,600,139	$2,914,745	-2.48%	$0.040	10.45%
4 Geo. 1 Yr Delay+2x20MW Priv. Geo.	$1,295,253	$0	$1,740,826	$3,036,079	1.57%	$0.042	16.02%
5 KPLC Geothermal-2Yr Delay	$1,081,846	$14,950	$2,079,918	$3,176,715	6.28%	$0.045	22.59%
6 Geo. 2 Yr Delay+50MW Priv. Geo.	$1,229,423	$4,510	$1,734,697	$2,968,629	-0.68%	$0.042	13.67%
7 Geo. 2 Yr Delay+2x20MW Priv. Geo.	$1,236,975	$0	$1,773,998	$3,010,973	0.73%	$0.042	15.51%
8 KPLC Hydro & Coal-1Yr Delay	$1,156,234	$0	$1,902,258	$3,058,493	2.32%	$0.043	17.60%
9 Hydro & Coal Delay+50MW Priv. Geo	$1,290,395	$0	$1,619,873	$2,910,268	-2.63%	$0.041	10.92%
10 Hydro & Coal Delay+2x20MW Priv. G	$1,284,384	$0	$1,696,978	$2,981,362	-0.26%	$0.042	13.93%
11 KPLC Hydro & Coal-2Yr Delay	$1,069,853	$0	$2,040,747	$3,110,600	4.07%	$0.044	20.12%
12 Hydro & Coal Delay+50MW Priv. Geo	$1,204,013	$0	$1,712,580	$2,916,593	-2.42%	$0.041	11.85%
13 Hydro & Coal Delay+2x20MW Priv. G	$1,198,003	$0	$1,801,708	$2,999,711	0.36%	$0.042	15.29%
14 KPLC Geothermal 25% Cost Rise	$1,373,546	$0	$1,746,390	$3,119,936	4.38%	$0.043	18.84%
15 KPLC Geo. Cost Rise+50MW Priv Geo	$1,384,061	$0	$1,655,410	$3,039,471	1.69%	$0.042	15.03%

Case 4 - High Forecast Demand Growth and High Oil Price Escalation Rates

Case 4 High Oil Price and High Forecast	Total Annual Capital Cost (000$)	Unserved Energy (000$)	Variable Costs (000$)	Total Costs (000$)	Change From Base (%)	Average Cost (000$)	Change From Base (%)
1 KPLC Base Case	$1,242,616	$300,686	$2,967,009	$4,510,312		$0.052	41.03%
2 KPLC Geothermal-1Yr Delay	$1,153,614	$802,860	$3,338,080	$5,294,554	17.39%	$0.056	51.93%
3 Geo. 1 Yr Delay+50MW Priv. Geo.	$1,314,606	$211,131	$2,570,635	$4,096,373	-9.18%	$0.047	29.65%
4 Geo. 1 Yr Delay+2x20MW Priv. Geo.	$1,295,253	$325,302	$2,799,730	$4,420,285	-2.00%	$0.050	37.65%
5 KPLC Geothermal-2Yr Delay	$1,081,846	$1,318,324	$3,638,531	$6,038,702	33.89%	$0.059	61.28%
6 Geo. 2 Yr Delay+50MW Priv. Geo.	$1,229,423	$528,038	$2,934,091	$4,691,552	4.02%	$0.051	40.50%
7 Geo. 2 Yr Delay+2x20MW Priv. Geo.	$1,236,975	$538,275	$3,049,777	$4,825,028	6.98%	$0.053	44.02%
8 KPLC Hydro & Coal-1Yr Delay	$1,156,234	$748,742	$3,303,707	$5,208,684	15.48%	$0.055	50.52%
9 Hydro & Coal Delay+50MW Priv. Geo	$1,290,395	$137,604	$2,662,271	$4,090,271	-9.31%	$0.049	32.93%
10 Hydro & Coal Delay+2x20MW Priv. Geo	$1,284,384	$188,850	$2,815,760	$4,288,995	-4.91%	$0.050	37.85%
11 KPLC Hydro & Coal-2Yr Delay	$1,069,853	$1,602,542	$3,640,404	$6,312,799	39.96%	$0.059	61.00%
12 Hydro & Coal Delay+50MW Priv. Geo	$1,204,013	$359,437	$2,998,969	$4,562,419	1.16%	$0.052	40.94%
13 Hydro & Coal Delay+2x20MW Priv. Geo	$1,198,003	$513,175	$3,152,458	$4,863,636	7.83%	$0.053	46.22%
14 KPLC Geothermal 25% Cost Rise	$1,373,546	$300,686	$2,967,009	$4,641,242	2.90%	$0.053	44.95%
15 KPLC Geo. Cost Rise+50MW Priv Geo	$1,384,061	$122,566	$2,700,261	$4,206,888	-6.73%	$0.050	35.94%

Levelized Costs for Various Capacity Alternatives
(Base Oil Prices and Other Assumptions)

		Capital	Fuel	Variable Cost	Total Cost
Oil Steam	Lev. Annual Cap Cost	117.09	464.37	11.30	592.76 $/kW/yr
	Annual Lev. Busbar Cost	0.015	0.062	0.003	0.080 $/kWh
Gas Turbine	Lev. Annual Cap Cost	81.57	909.12	15.31	1006.00 $/kW/yr
	Annual Lev. Busbar Cost	0.010	0.135	0.005	0.150 $/kWh
Geothermal	Lev. Annual Cap Cost	317.89	0.00	18.90	336.79 $/kW/yr
	Annual Lev. Busbar Cost	0.039	0.000	0.005	0.044 $/kWh
Coal	Lev. Annual Cap Cost	152.25	204.04	12.61	368.91 $/kW/yr
	Annual Lev. Busbar Cost	0.021	0.029	0.006	0.055 $/kWh
Sondu	Lev. Annual Cap Cost	264.13	0.00	0.00	264.13 $/kW/yr
	Annual Lev. Busbar Cost	0.046	0.000	0.001	0.047 $/kWh
Sererwa	Lev. Annual Cap Cost	184.35	0.00	0.00	184.35 $/kW/yr
	Annual Lev. Busbar Cost	0.082	0.000	0.002	0.084 $/kWh
Magwagwa	Lev. Annual Cap Cost	540.66	0.00	0.00	540.66 $/kW/yr
	Annual Lev. Busbar Cost	0.155	0.000	0.001	0.156 $/kWh
Private Geo Suswa	Lev. Annual Cap Cost	287.20	0.00	24.30	311.50 $/kW/yr
	Annual Lev. Busbar Cost	0.036	0.000	0.007	0.043 $/kWh
Private Geo Small	Lev. Annual Cap Cost	410.34	0.00	45.45	455.79 $/kW/yr
	Annual Lv Busbar Cost	0.046	0.000	0.013	0.058 $/kWh

Levelized Annual Capacity Costs (LAC)

Levelization Formula:
LAC = (CC * FCR + FOM) + (FC * LF * HR * HRS) + (VOM * LF * HRS)

CC	Derated capital cost/KW
FCR	Fixed change rate
FOM	Fixed O&M
FC	Fuel cost
HR	Heat rate
HRS	Hours of operation
LF	Levelization factor (for escalation of cost)
VOM	Variable O&M
LF	Levelization factor
HRS	Hours of operation

Notes:

1. Derated capital cost/KW = capital cost/(1-forced outage rate)

2. FCR based on economic life, discount rate of 10%

3. LF modifies constant $ amounts for effects of real price escalation (differential vs. other commodities)

Expense Plan Scenario Tables for Base Case Section III

Appendix III

The Kenya Power and Lighting Company -- Expansion Plan Analysis

SCENARIO CASE
Name: geodelaylyr

Forecast: 5.4% / Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(67.8)	(48.6)	(30.7)	(72.3)	(122.4)	(60.1)	(55.8)	(114.4)	(61.2)	(126.3)	(168.5)
Energy Balance (GWH) +/-	231.1	486.0	(6.9)	241.1	553.0	475.1	561.4	1,162.8	1,308.2	1,018.2	1,574.9	1,252.8	1,152.3
CAPACITY ADDITIONS (MW)	30	90	90	152	215	232.9	232.9	347.9	407.9	407.9	522.9	522.9	637.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	607.1	1,066.6	1,601.4	1,758.4	2,092.4	2,954.7	3,375.2	3,375.2	4,237.5	4,237.5	5,099.8
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				32	32			55			55		55
Cost/kWh ($)				$0.039	$0.039			$0.039			$0.039		$0.039
Max. GWH's (000's)				257	514	514	514	956	956	956	1398	1398	1840
Annual Cap. Cost (000$)				$10,032	$20,064	$20,064	$20,064	$37,298	$37,298	$37,298	$54,533	$54,533	$71,768
Incremental An. Cost (000$)				$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0	$17,235
GWH Change from Base				-257	0	0	-442	0	0	-442	0	-442	0
					HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$6,021	$18,060	$40,781	$53,586	$79,796	$105,700	$114,369	$114,369	$140,274	$140,274	$166,178
Incremental Capital Cost	$2,007	$4,014	$0	$12,039	$22,721	$12,805	$26,210	$25,904	$8,670	$0	$25,904	$0	$25,904
Total Variable Cost	$87,277	$113,023	$159,794	$157,512	$119,089	$129,301	$118,612	$58,164	$88,554	$91,317	$102,801	$105,942	$94,488

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: gdelay1+50pr

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(17.8)	1.4	19.3	(22.3)	(72.4)	(10.1)	(5.8)	(64.4)	(11.2)	(76.3)	(118.5)
Energy Balance (GWH) +/-	231.1	486.0	387.3	635.3	947.2	869.3	955.6	1,557.0	1,702.4	1,412.4	1,969.1	1,647.0	1,546.5
CAPACITY ADDITIONS (MW)	30	90	140	202	265	282.9	282.9	397.9	457.9	457.9	572.9	572.9	687.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	1,001.3	1,460.8	1,995.6	2,152.6	2,486.6	3,348.9	3,769.4	3,769.4	4,631.7	4,631.7	5,494.0
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			50	32	32			55			55		55
Cost/kWh ($)			$0.034	$0.039	$0.039			$0.039			$0.039		$0.039
Max. GWH's (000's)			394	651	909	909	909	1350	1350	1350	1792	1792	2234
Annual Cap. Cost (000$)			$13,416	$23,448	$33,480	$33,480	$33,480	$50,714	$50,714	$50,714	$67,949	$67,949	$85,184
Incremental An. Cost (000$)			$13,416	$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0	$17,235
GWH Change from Base			137	137	394	394	-48	394	394	-48	394	-48	394
					HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$19,437	$31,476	$54,197	$67,002	$93,212	$119,116	$127,785	$127,785	$153,690	$153,690	$179,594
Incremental Capital Cost	$2,007	$4,014	$13,416	$12,039	$22,721	$12,805	$26,210	$25,904	$8,670	$0	$25,904	$0	$25,904
Total Variable Cost	$87,277	$113,023	$111,152	$108,870	$70,447	$80,660	$69,970	$73,582	$86,739	$89,566	$100,987	$104,127	$96,517

SCENARIO CASE   The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name:	gdelay1+2x20pr													
Forecast:	5.4%													
Oil Pr Grwt	4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS														
Capacity Balance (MW) +/-		(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-		28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)														
Capacity Balance (MW) +/-		(48.8)	(27.3)	(47.8)	(28.6)	(10.7)	(32.3)	(82.4)	(20.1)	(15.8)	(74.4)	(21.2)	(86.3)	(128.5)
Energy Balance (GWH) +/-		231.1	486.0	150.7	398.8	710.7	790.4	876.8	1,478.1	1,623.5	1,333.6	1,890.3	1,568.2	1,467.6
CAPACITY ADDITIONS (MW)		30	90	110	172	235	272.9	272.9	387.9	447.9	447.9	562.9	562.9	677.9
ADDITIONAL ENERGY (GWH)		202.4	607.1	764.7	1,224.3	1,759.1	2,073.8	2,407.8	3,270.1	3,690.6	3,690.6	4,552.9	4,552.9	5,415.2
KPLC GAS TURBINE ADDITION		30	60		30									
Cost/kWh ($)		$0.010	$0.010		$0.010									
Max. GWH's (000's)		202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)		$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)		$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base		0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				20	32	32	20		55			55		55
Cost/kWh ($)				$0.043	$0.039	$0.039	$0.043		$0.039			$0.039		$0.039
Max. GWH's (000's)				157.7	415	672	829.7	830	1272	1272	1272	1713	1713	2155
Annual Cap. Cost (000$)				$6,745	$16,777	$26,808	$33,553	$33,553	$50,788	$50,788	$50,788	$68,022	$68,022	$85,257
Incremental An. Cost (000$)				$6,745	$10,032	$10,032	$6,745	$0	$17,235	$0	$0	$17,235	$0	$17,235
GWH Change from Base				-100	-100	158	315	-126	315	315	-126	315	-126	315
						HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS						31	17.9		60	60		60		60
Cost/kWh ($)						$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)						277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)						$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)						$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base						0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost		$2,007	$6,021	$12,766	$24,805	$47,526	$67,076	$93,285	$119,189	$127,859	$127,859	$153,763	$153,763	$179,667
Incremental Capital Cost		$2,007	$4,014	$6,745	$12,039	$22,721	$19,550	$26,210	$25,904	$8,670	$0	$25,904	$0	$25,904
Total Variable Cost		$87,277	$113,023	$140,337	$138,055	$99,632	$90,388	$79,698	$73,945	$87,102	$89,929	$101,350	$104,490	$96,111

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: geldl2years

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(67.8)	(80.6)	(62.7)	(72.3)	(122.4)	(115.1)	(55.8)	(114.4)	(116.2)	(126.3)	(223.5)
Energy Balance (GWH) +/-	231.1	486.0	(6.9)	(16.1)	295.8	475.1	561.4	720.9	1,308.2	1,018.2	1,133.1	1,252.8	710.4
CAPACITY ADDITIONS (MW)	30	90	90	120	183	232.9	232.9	292.9	407.9	407.9	467.9	522.9	582.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	607.1	809.4	1,344.2	1,758.4	2,092.4	2,512.9	3,375.2	3,375.2	3,795.7	4,237.5	4,658.0
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS					32	32			55			55	
Cost/kWh ($)					$0.039	$0.039			$0.039			$0.039	
Max. GWH's (000's)					257	514	514	514	956	956	956	1398	1398
Annual Cap. Cost (000$)					$10,032	$20,064	$20,064	$20,064	$37,298	$37,298	$37,298	$54,533	$54,533
Incremental An. Cost (000$)					$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0
GWH Change from Base					-257	0	-442	-442	0	-442	-442	-442	-442
					HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$6,021	$8,029	$30,749	$53,586	$79,796	$88,465	$114,369	$114,369	$123,039	$140,274	$148,943
Incremental Capital Cost	$2,007	$4,014	$0	$2,007	$22,721	$22,837	$26,210	$8,670	$25,904	$0	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$159,794	$189,247	$150,824	$129,301	$118,612	$112,684	$88,554	$91,317	$91,123	$105,942	$113,816

SCENARIO CASE	The Kenya Power and Lighting Company -- Expansion Plan Analysis												
Name: geod2yr+50pr													
Forecast: 5.4%													
Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(67.8)	(30.6)	(12.7)	(22.3)	(72.4)	(65.1)	(5.8)	(64.4)	(66.2)	(76.3)	(173.5)
Energy Balance (GWH) +/-	231.1	486.0	(6.9)	378.1	690.0	869.3	955.6	1,115.1	1,702.4	1,412.4	1,527.3	1,647.0	1,104.6
CAPACITY ADDITIONS (MW)	30	90	90	170	233	282.9	282.9	342.9	457.9	457.9	517.9	572.9	632.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	607.1	1,203.6	1,738.4	2,152.6	2,486.6	2,907.1	3,769.4	3,769.4	4,189.9	4,631.7	5,052.2
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				50	32	32			55			55	
Cost/kWh ($)				$0.034	$0.039	$0.039			$0.039			$0.039	
Max. GWH's (000's)				394	651	909	909	909	1350	1350	1350	1792	1792
Annual Cap. Cost (000$)				$13,416	$23,448	$33,480	$33,480	$33,480	$50,714	$50,714	$50,714	$67,949	$67,949
Incremental An. Cost (000$)				$13,416	$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0
GWH Change from Base				-120	137	394	-48	-48	394	-48	-48	-48	-48
					HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$6,021	$21,445	$44,165	$67,002	$93,212	$101,881	$127,785	$127,785	$136,455	$153,690	$162,359
Incremental Capital Cost	$2,007	$4,014	$0	$15,423	$22,721	$22,837	$26,210	$8,670	$25,904	$0	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$159,794	$140,605	$102,182	$80,660	$69,970	$64,043	$86,739	$89,566	$103,021	$104,127	$94,243

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: geod2yr+2x20pr

Forecast: 5.4%													
Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(67.8)	(60.6)	(42.7)	(52.3)	(82.4)	(75.1)	(15.8)	(74.4)	(76.2)	(86.3)	(183.5)
Energy Balance (GWH) +/-	231.1	486.0	(6.9)	141.6	453.5	632.7	876.8	1,036.3	1,623.5	1,333.6	1,448.5	1,568.2	1,025.8
CAPACITY ADDITIONS (MW)	30	90	90	140	203	252.9	272.9	332.9	447.9	447.9	507.9	562.9	622.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	607.1	967.1	1,501.9	1,916.1	2,407.8	2,828.2	3,690.6	3,690.6	4,111.0	4,552.9	4,973.4
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				20	32	32	20		55			55	
Cost/kWh ($)				$0.043	$0.039	$0.039	$0.043		$0.039			$0.039	
Max. GWH's (000's)				157.7	415	672	829.7	830	1272	1272	1272	1713	1713
Annual Cap. Cost (000$)				$6,745	$16,777	$26,808	$33,553	$33,553	$50,788	$50,788	$50,788	$68,022	$68,022
Incremental An. Cost (000$)				$6,745	$10,032	$10,032	$6,745	$0	$17,235	$0	$0	$17,235	$0
GWH Change from Base				-357	-100	156	-126	-126	315	-126	-126	-126	-126
					HYDRO	HYDRO	HYDRO		Coal	Coal			Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$6,021	$14,773	$37,494	$60,331	$93,285	$101,955	$127,859	$127,859	$136,528	$153,763	$162,433
Incremental Capital Cost	$2,007	$4,014	$0	$8,752	$22,721	$22,837	$32,954	$8,670	$25,904	$0	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$159,794	$169,790	$131,367	$109,845	$79,698	$73,771	$87,102	$89,929	$103,384	$104,490	$93,838

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal1yr

Forecast:	5.4%													
Oil Pr Grwt	4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS														
Capacity Balance (MW) +/-		(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-		28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)														
Capacity Balance (MW) +/-		(48.8)	(27.3)	(35.8)	(16.6)	(61.7)	(90.2)	(67.4)	(120.1)	(115.8)	(59.4)	(121.2)	(71.3)	(228.5)
Energy Balance (GWH) +/-		231.1	486.0	250.2	498.3	275.4	318.1	669.3	742.3	887.7	1,460.1	1,154.5	1,694.7	731.8
CAPACITY ADDITIONS (MW)		30	90	122	184	184	215	287.9	287.9	347.9	462.9	462.9	577.9	577.9
ADDITIONAL ENERGY (GWH)		202.4	607.1	864.3	1,323.8	1,323.8	1,601.4	2,200.2	2,534.2	2,954.7	3,817.0	3,817.0	4,679.4	4,679.4
KPLC GAS TURBINE ADDITION		30	60		30									
Cost/kWh ($)		$0.010	$0.010		$0.010									
Max. GWH's (000's)		202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)		$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)		$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base		0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				32	32			55			55		55	
Cost/kWh ($)				$0.039	$0.039			$0.039			$0.039		$0.039	
Max. GWH's (000's)				257	514	514	514	956	956	956	1398	1398	1840	1840
Annual Cap. Cost (000$)				$10,032	$20,064	$20,064	$20,064	$37,298	$37,298	$37,298	$54,533	$54,533	$71,768	$71,768
Incremental An. Cost (000$)				$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base				0	0	0	0	0	0	0	0	0	0	0
							HYDRO	HYDRO	HYDRO	Coal	Coal		Coal	
KPLC OTHER ADDITIONS							31	17.9		60	60		60	
Cost/kWh ($)							$0.046	$0.082	$0.15	$0.021	$0.021		$0.021	
Max. GWH's (000's)							277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04
Annual Cap. Cost (000$)							$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712
Incremental An. Cost (000$)							$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0
GWH Change from Base							-157	-334	-420.48	-420.48	0	-420.48	0	-420.48
Cost - Total An. Cap Cost		$2,007	$6,021	$16,053	$28,092	$28,092	$40,781	$70,821	$97,030	$105,700	$131,604	$131,604	$157,508	$157,508
Incremental Capital Cost		$2,007	$4,014	$10,032	$12,039	$0	$12,689	$30,040	$26,210	$8,670	$25,904	$0	$25,904	$0
Total Variable Cost		$87,277	$113,023	$128,059	$125,777	$154,428	$149,288	$106,610	$97,640	$93,524	$89,347	$76,078	$103,908	$98,532

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal1yr+50prg

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(11.7)	(40.2)	(17.4)	(70.1)	(65.8)	(9.4)	(71.2)	(21.3)	(178.5)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	669.6	712.3	1,063.5	1,136.5	1,281.9	1,854.3	1,548.7	2,088.9	1,126.0
CAPACITY ADDITIONS (MW)	30	90	122	184	234	265	337.9	337.9	397.9	512.9	512.9	627.9	627.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,718.0	1,995.6	2,594.4	2,928.4	3,348.9	4,211.2	4,211.2	5,073.6	5,073.6
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			32	32	50		55			55		55	
Cost/kWh ($)			$0.039	$0.039	$0.034		$0.039			$0.039		$0.039	
Max. GWH's (000's)			257	514	909	909	1350	1350	1350	1792	1792	2234	2234
Annual Cap. Cost (000$)			$10,032	$20,064	$33,480	$33,480	$50,714	$50,714	$50,714	$67,949	$67,949	$85,184	$85,184
Incremental An. Cost (000$)			$10,032	$10,032	$13,416	$0	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base			0	0	394	394	394	394	394	394	394	394	394
						HYDRO	HYDRO	HYDRO	Coal	Coal			Coal
KPLC OTHER ADDITIONS						31	17.9		60	60		60	
Cost/kWh ($)						$0.046	$0.082	$0.15	$0.021	$0.021		$0.021	
Max. GWH's (000's)						277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04
Annual Cap. Cost (000$)						$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712
Incremental An. Cost (000$)						$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0
GWH Change from Base						-157	-334	-420.48	-420.48	0	-420.48	0	-420.48
Cost - Total An. Cap Cost	$2,007	$6,021	$16,053	$28,092	$41,508	$54,197	$84,237	$110,446	$119,116	$145,020	$145,020	$170,924	$170,924
Incremental Capital Cost	$2,007	$4,014	$10,032	$12,039	$13,416	$12,689	$30,040	$26,210	$8,670	$25,904	$0	$25,904	$0
Total Variable Cost	$87,277	$113,023	$128,059	$125,777	$105,786	$100,646	$57,968	$48,998	$76,264	$87,532	$90,511	$102,093	$81,942

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal1yr+2x20prg

Forecast: 5.4%

Oil Pr Grwt	4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS														
Capacity Balance (MW) +/-		(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-		28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)														
Capacity Balance (MW) +/-		(48.8)	(27.3)	(35.8)	(16.6)	(41.7)	(50.2)	(27.4)	(80.1)	(75.8)	(19.4)	(81.2)	(31.3)	(188.5)
Energy Balance (GWH) +/-		231.1	486.0	250.2	498.3	433.1	633.4	984.6	1,057.7	1,203.0	1,775.4	1,469.8	2,010.0	1,047.1
CAPACITY ADDITIONS (MW)		30	90	122	184	204	255	327.9	327.9	387.9	502.9	502.9	617.9	617.9
ADDITIONAL ENERGY (GWH)		202.4	607.1	864.3	1,323.8	1,481.5	1,916.8	2,515.6	2,849.6	3,270.1	4,132.4	4,132.4	4,994.7	4,994.7
KPLC GAS TURBINE ADDITION		30	60		30									
Cost/kWh ($)		$0.010	$0.010		$0.010									
Max. GWH's (000's)		202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)		$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)		$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base		0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS				32	32	20	20	55			55		55	
Cost/kWh ($)				$0.039	$0.039	$0.043	$0.043	$0.039			$0.039		$0.039	
Max. GWH's (000's)				257	514	672.0	829.7	1272	1272	1272	1713	1713	2155	2155
Annual Cap. Cost (000$)				$10,032	$20,064	$26,808	$33,553	$50,788	$50,788	$50,788	$68,022	$68,022	$85,257	$85,257
Incremental An. Cost (000$)				$10,032	$10,032	$6,745	$6,745	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base				0	0	158	315	315	315	315	315	315	315	315
							HYDRO	HYDRO	HYDRO	Coal	Coal			Coal
KPLC OTHER ADDITIONS							31	17.9		60	60		60	
Cost/kWh ($)							$0.046	$0.082	$0.15	$0.021	$0.021		$0.021	
Max. GWH's (000's)							277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04
Annual Cap. Cost (000$)							$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712
Incremental An. Cost (000$)							$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0
GWH Change from Base							-157	-334	-420.48	-420.48	0	-420.48	0	-420.48
Cost - Total An. Cap Cost		$2,007	$6,021	$16,053	$28,092	$34,837	$54,270	$84,310	$110,520	$119,189	$145,093	$145,093	$170,998	$170,998
Incremental Capital Cost		$2,007	$4,014	$10,032	$12,039	$6,745	$19,434	$30,040	$26,210	$8,670	$25,904	$0	$25,904	$0
Total Variable Cost		$87,277	$113,023	$128,059	$125,777	$134,971	$110,374	$67,697	$58,726	$76,626	$87,895	$90,874	$102,456	$81,536

SCENARIO CASE The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal2yr

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(61.7)	(121.2)	(85.3)	(120.1)	(175.8)	(119.4)	(121.2)	(131.3)	(228.5)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	275.4	40.5	512.3	408.3	467.2	1,039.6	1,154.5	1,274.2	731.8
CAPACITY ADDITIONS (MW)	30	90	122	184	184	184	270	287.9	287.9	402.9	462.9	517.9	577.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,323.8	1,323.8	2,043.2	2,200.2	2,534.2	3,396.6	3,817.0	4,258.9	4,679.4
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			32	32			55			55		55	
Cost/kWh ($)			$0.039	$0.039			$0.039			$0.039		$0.039	
Max. GWH's (000's)			257	514	514	514	956	956	956	1398	1398	1840	1840
Annual Cap. Cost (000$)			$10,032	$20,064	$20,064	$20,064	$37,298	$37,298	$37,298	$54,533	$54,533	$71,768	$71,768
Incremental An. Cost (000$)			$10,032	$10,032	$0	$0	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base			0	0	0	0	0	0	0	0	0	0	0
							HYDRO	HYDRO		Coal	Coal		
KPLC OTHER ADDITIONS							31	17.9		60	60		60
Cost/kWh ($)							$0.046	$0.082	$0.15	$0.021	$0.021		$0.021
Max. GWH's (000's)							277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04
Annual Cap. Cost (000$)							$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712
Incremental An. Cost (000$)							$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670
GWH Change from Base							-491	-754.48	-840.96	-420.48	-420.48	-420.48	-420.48
Cost - Total An. Cap Cost	$2,007	$6,021	$16,053	$28,092	$28,092	$28,092	$58,016	$70,821	$97,030	$122,934	$131,604	$148,839	$157,508
Incremental Capital Cost	$2,007	$4,014	$10,032	$12,039	$0	$0	$29,923	$12,805	$26,210	$25,904	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$128,059	$125,777	$154,428	$184,627	$126,597	$140,158	$132,999	$76,272	$76,078	$93,432	$98,532

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal2yr+ 50 prg

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(11.7)	(71.2)	(35.3)	(70.1)	(125.8)	(69.4)	(71.2)	(81.3)	(178.5)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	669.6	434.7	906.5	802.5	861.4	1,433.8	1,548.7	1,668.4	1,126.0
CAPACITY ADDITIONS (MW)	30	90	122	184	234	234	320	337.9	337.9	452.9	512.9	567.9	627.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,718.0	1,718.0	2,437.4	2,594.4	2,928.4	3,790.8	4,211.2	4,653.1	5,073.6
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			32	32	50		55			55		55	
Cost/kWh ($)			$0.039	$0.039	$0.034		$0.039			$0.039		$0.039	
Max. GWH's (000's)			257	514	909	909	1350	1350	1350	1792	1792	2234	2234
Annual Cap. Cost (000$)			$10,032	$20,064	$33,480	$33,480	$50,714	$50,714	$50,714	$67,949	$67,949	$85,184	$85,184
Incremental An. Cost (000$)			$10,032	$10,032	$13,416	$0	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base			0	0	394	394	394	394	394	394	394	394	394
							HYDRO	HYDRO		Coal	Coal		
KPLC OTHER ADDITIONS							31	17.9		60	60		60
Cost/kWh ($)							$0.046	$0.082	$0.15	$0.021	$0.021		$0.021
Max. GWH's (000's)							277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04
Annual Cap. Cost (000$)							$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712
Incremental An. Cost (000$)							$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670
GWH Change from Base							-491	-754.48	-840.96	-420.48	-420.48	-420.48	-420.48
Cost - Total An. Cap Cost	$2,007	$6,021	$16,053	$28,092	$41,508	$41,508	$71,432	$84,237	$110,446	$136,351	$145,020	$162,255	$170,924
Incremental Capital Cost	$2,007	$4,014	$10,032	$12,039	$13,416	$0	$29,923	$12,805	$26,210	$25,904	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$128,059	$125,777	$105,786	$135,985	$77,955	$91,516	$84,357	$77,056	$90,511	$91,617	$81,942

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: hyd+coal2yr+2x20prg

Forecast: 5.4%													
Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(41.7)	(81.2)	(45.3)	(80.1)	(135.8)	(79.4)	(81.2)	(91.3)	(188.5)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	433.1	355.8	827.6	723.7	782.6	1,354.9	1,469.8	1,589.6	1,047.1
CAPACITY ADDITIONS (MW)	30	90	122	184	204	224	310	327.9	327.9	442.9	502.9	557.9	617.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,481.5	1,639.2	2,358.6	2,515.6	2,849.6	3,711.9	4,132.4	4,574.2	4,994.7
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			32	32	20	20	55			55		55	
Cost/kWh ($)			$0.039	$0.039	$0.043	$0.043	$0.039			$0.039		$0.039	
Max. GWH's (000's)			257	514	672.0	829.7	1272	1272	1272	1713	1713	2155	2155
Annual Cap. Cost (000$)			$10,032	$20,064	$26,808	$33,553	$50,788	$50,788	$50,788	$68,022	$68,022	$85,257	$85,257
Incremental An. Cost (000$)			$10,032	$10,032	$6,745	$6,745	$17,235	$0	$0	$17,235	$0	$17,235	$0
GWH Change from Base			0	0	158	315	315	315	315	315	315	315	315
							HYDRO	HYDRO		Coal	Coal		
KPLC OTHER ADDITIONS							31	17.9		60	60		60
Cost/kWh ($)							$0.046	$0.082	$0.15	$0.021	$0.021		$0.021
Max. GWH's (000's)							277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04
Annual Cap. Cost (000$)							$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712
Incremental An. Cost (000$)							$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670
GWH Change from Base							-491	-754.48	-840.96	-420.48	-420.48	-420.48	-420.48
Cost - Total An. Cap Cost	$2,007	$6,021	$16,053	$28,092	$34,837	$41,582	$71,505	$84,310	$110,520	$136,424	$145,093	$162,328	$170,998
Incremental Capital Cost	$2,007	$4,014	$10,032	$12,039	$6,745	$6,745	$29,923	$12,805	$26,210	$25,904	$8,670	$17,235	$8,670
Total Variable Cost	$87,277	$113,023	$128,059	$125,777	$134,971	$145,713	$87,683	$101,245	$94,086	$77,419	$90,874	$91,980	$81,536

Appendix III - 13

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: kplcgeo+25%

Forecast: 5.4%													
Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(35.8)	(16.6)	(30.7)	(72.3)	(67.4)	(60.1)	(55.8)	(59.4)	(61.2)	(71.3)	(168.5)
Energy Balance (GWH) +/-	231.1	486.0	250.2	498.3	553.0	475.1	1,003.3	1,162.8	1,308.2	1,460.1	1,574.9	1,694.7	1,152.3
CAPACITY ADDITIONS (MW)	30	90	122	184	215	232.9	287.9	347.9	407.9	462.9	522.9	577.9	637.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	864.3	1,323.8	1,601.4	1,758.4	2,534.2	2,954.7	3,375.2	3,817.0	4,237.5	4,679.4	5,099.8
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			32	32			55			55		55	
Cost/kWh ($)			$0.049	$0.049			$0.049			$0.049		$0.049	
Max. GWH's (000's)			257	514	514	514	956	956	956	1398	1398	1840	1840
Annual Cap. Cost (000$)			$12,540	$25,080	$25,080	$25,080	$46,623	$46,623	$46,623	$68,166	$68,166	$89,709	$89,709
Incremental An. Cost (000$)			$12,540	$12,540	$0	$0	$21,543	$0	$0	$21,543	$0	$21,543	$0
GWH Change from Base			0	0	0	0	0	0	0	0	0	0	0
					HYDRO	HYDRO		Coal	Coal		Coal		Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$18,561	$33,108	$45,797	$58,602	$106,355	$115,024	$123,694	$145,237	$153,907	$175,450	$184,120
Incremental Capital Cost	$2,007	$4,014	$12,540	$14,547	$12,689	$12,805	$47,753	$8,670	$8,670	$21,543	$8,670	$21,543	$8,670
Total Variable Cost	$87,277	$113,023	$128,059	$125,777	$119,089	$129,301	$64,091	$58,164	$88,554	$89,347	$102,801	$103,908	$94,488

SCENARIO CASE — The Kenya Power and Lighting Company -- Expansion Plan Analysis

Name: kplcgeo+25%+50MWpr

Forecast: 5.4%

Oil Pr Grwt 4.0%	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04	2004-05
STARTING CAPACITY/ENERGY REQUIREMENTS													
Capacity Balance (MW) +/-	(78.8)	(117.3)	(157.8)	(200.6)	(245.7)	(305.2)	(355.3)	(408.0)	(463.7)	(522.3)	(584.1)	(649.2)	(806.4)
Energy Balance (GWH) +/-	28.7	(121.0)	(614.0)	(825.5)	(1,048.4)	(1,283.3)	(1,530.9)	(1,791.9)	(2,067.0)	(2,357.0)	(2,662.6)	(2,984.7)	(3,947.6)
BALANCE AFTER EXPANSION PROGRAM (BELOW)													
Capacity Balance (MW) +/-	(48.8)	(27.3)	(17.8)	1.4	(12.7)	(54.3)	(49.4)	(42.1)	(37.8)	(41.4)	(43.2)	(53.3)	(150.5)
Energy Balance (GWH) +/-	231.1	486.0	387.3	635.3	690.0	612.1	1,140.3	1,299.8	1,445.2	1,597.1	1,712.0	1,831.7	1,289.3
CAPACITY ADDITIONS (MW)	30	90	140	202	233	250.9	305.9	365.9	425.9	480.9	540.9	595.9	655.9
ADDITIONAL ENERGY (GWH)	202.4	607.1	1,001.3	1,460.8	1,738.4	1,895.4	2,671.3	3,091.7	3,512.2	3,954.1	4,374.5	4,816.4	5,236.9
KPLC GAS TURBINE ADDITION	30	60		30									
Cost/kWh ($)	$0.010	$0.010		$0.010									
Max. GWH's (000's)	202.4	607.1	607.1	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4	809.4
Annual Cap. Cost (000$)	$2,007	$6,021	$6,021	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029	$8,029
Incremental An. Cost (000$)	$2,007	$4,014	$0	$2,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
GWH Change from Base	0	0	0	0	0	0	0	0	0	0	0	0	0
KPLC GEOTHERMAL ADDITIONS			50	32			55			55		55	
Cost/kWh ($)			$0.034	$0.049			$0.049			$0.049		$0.049	
Max. GWH's (000's)			394	651	651	651	1093	1093	1093	1535	1535	1977	1977
Annual Cap. Cost (000$)			$13,416	$25,956	$25,956	$25,956	$47,499	$47,499	$47,499	$69,042	$69,042	$90,586	$90,586
Incremental An. Cost (000$)			$13,416	$12,540	$0	$0	$21,543	$0	$0	$21,543	$0	$21,543	$0
GWH Change from Base			137	137	137	137	137	137	137	137	137	137	137
					HYDRO	HYDRO		Coal	Coal		Coal		Coal
KPLC OTHER ADDITIONS					31	17.9		60	60		60		60
Cost/kWh ($)					$0.046	$0.082	$0.15	$0.021	$0.021		$0.021		$0.021
Max. GWH's (000's)					277.6	434.6	768.6	1189.08	1609.56	1609.56	2030.04	2030.04	2450.52
Annual Cap. Cost (000$)					$12,689	$25,494	$51,704	$60,373	$69,043	$69,043	$77,712	$77,712	$86,382
Incremental An. Cost (000$)					$12,689	$12,805	$26,210	$8,670	$8,670	$0	$8,670	$0	$8,670
GWH Change from Base					0	0	0	0	0	0	0	0	0
Cost - Total An. Cap Cost	$2,007	$6,021	$19,437	$33,984	$46,673	$59,478	$107,231	$115,901	$124,570	$146,114	$154,783	$176,326	$184,996
Incremental Capital Cost	$2,007	$4,014	$13,416	$14,547	$12,689	$12,805	$47,753	$8,670	$8,670	$21,543	$8,670	$21,543	$8,670
Total Variable Cost	$87,277	$113,023	$111,152	$108,870	$102,182	$112,394	$47,184	$74,766	$87,923	$88,716	$102,171	$103,277	$95,193

Spreadsheets for Suswa, Eburru and Arus

Appendix IV

LEGAL NOTICE No. 205

THE GEOTHERMAL RESOURCES ACT, 1982

(*No. 12 of 1982*)

COMMENCEMENT

IN EXERCISE of the powers conferred by section 1 of the Geothermal Resources Act, the Minister for Energy appoints the 1st May, 1990 as the date on which the Act hall come into operation.

Made on the 24th April, 1990.

K. N. K. BIWOTT,
Minister for Energy.

LEGAL NOTICE No. 206

THE GEOTHERMAL RESOURCES ACT, 1982

(*No. 12 of 1982*)

IN EXERCISE of the powers conferred by section 24 of the Geothermal Resources Act, the Minister for Energy makes the following Regulations:—

THE GEOTHERMAL RESOURCES REGULATIONS, 1990

PART I—PRELIMINARY

Citation.

1. These Regulations may be cited as the Geothermal Resources Regulations, 1990.

PART II—APPLICATION FOR AUTHORITY AND LICENCE

Application for authority to search for geothermal resources.

2. (1) The application for an authority under section 6 of the Act shall be made to the Minister in writing in respect of any land and shall specify—

(*a*) the name, nationality, nature of business and the principal place of business of the applicant;

(*b*) the name and nationality of every director or equivalent officer where the applicant is a company, corporation or other body corporate; and, if the body corporate has a share capital the name of any person who is the beneficial owner of more than five per centum of the issued share capital;

(*c*) the delineation of the area or areas proposed to be covered by the authority;

(*d*) the particulars of work and minimum expenditure proposed to be carried out or expended in respect of the area over which the authority is sought, and a statement of any significant adverse effect which the proposed operations would have on the environment and proposals for controlling or eliminating that effect.

(2) The Minister may call for such additional information as he may require under this regulation to enable him to assess the suitability of a grant of the authority to the applicant.

(3) The Minister may, when granting an authortiy to explore, also grant to the holder of that authority the right to be granted, on application, a geothermal resources licence in agreed terms in respect of all or part or parts of the area covered by that authority.

Geothermal resources licence.

3. (1) A geothermal resources licence granted under section 7 of the Act, shall be negotiated on the basis of the model licence set out in the First Schedule.

(2) A geothermal resources licence may be accompanied by, or be conditional upon, the execution of a contract (to be known as a "geothermal resources contract") between the licensee and the relevant Government department or other body designated by the Minister for the purpose of providing for the utilization of the geothermal resources.

(3) The Minister shall in granting a geothermal resources licence, allow an exploration phase of a period not exceeding five years and if at the end of that period no geothermal resources of a potential commercial interest is discovered the Minister may require the licensee to surrender the licensed area.

(4) Where the licensee, during the exploration phase, discovers a geothermal resources which is of potential commercial interest, he shall within a period of sixty days after the discovery submit an appraisal programme to the Minister for his approval.

(5) If the appraisal programme results into the declaration by the Minister and the licensee of a visible commercial geothermal resources, the licensee shall, within twelve months from the date of the declaration, submit to the Minister a development and production programme which shall include—

(*a*) the date by which the applicant intends to commence production;

(*b*) the capacity of production and scale of operations;

(*c*) the estimated overall production;

(*d*) the marketing arrangements made for disposal of the geothermal energy, including details of all contracts or arrangements made with proposed users;

(*e*) proposals for the prevention of pollution, the treatment of wastes, the safeguarding of natural resources, the progressive reclamation and rehabilitation of lands disturbed by prospecting or production operations and for the minimization of the effect of such operations on adjoining or neighbouring lands; and

(*f*) a statement of any significant adverse effect which the carrying out of production operations would be likely to have on the environment and proposals for controlling or eliminating that effect;

(g) a technical report on the production possibilities and the intention of the applicant in relation thereto; and

(h) a detailed forecast of capital investment, operating costs and sales reserves and the anticipated type and source of financing.

(6) The development and production phase shall commence upon the approval by the Minister of the development and production programme.

Application for geothermal resources licence.

4. (1) The application for the grant of a geothermal resources licence may be made to the Minister in respect of any geothermal resources area and shall specify—

(a) the name and nationality, nature of business and the principal place of business of the applicant;

(b) the name and nationality of every director or equivalent officer where the applicant is a company, corporation or other body corporate and if the body corporate has a share capital, the name of any person who is the beneficial owner of more than five per centum of the issued share capital;

(c) a full statement giving the applicant's financial status, technical competence and experience;

(d) the delineation of the area proposed to be covered by the geothermal resources licence together with a plan of the area;

(e) a general statement of the proposed programme of exploration of the geothermal resources, including a comprehensive report on the location, nature and characteristics of the source of geothermal energy to be explored;

(f) the terms on which the applicant proposes to negotiate;

(g) proposals with respect to the employment and training of citizens of Kenya;

(h) the goods and services required for the production operations which can be obtained within Kenya and the applicant's intention in relation thereto; and

(i) details of expected infrastructure requirements.

(2) The Minister may call for such additional information as he may require under this regulation to enable him to assess the suitability of the grant of a geothermal resources licence.

Renewal of licence.

5. (1) An application for the renewal of a geothermal resources licence under section 9 of the Act—

(a) shall, subject to paragraph 3 (4), be made not later than twelve months before the day on which the licence is due to expire; and

(b) shall be accompanied by—

(i) particulars of work carried out, and the amounts expended in respect of the geothermal resources area up to and including a date not earlier than one month immediately preceding the date of the application; and

(ii) proposals of the applicant for work and minimum expenditure in respect of the geothermal resource area during the renewal period being applied for;

(c) may set out any other matter that the applicant wishes the Minister to consider.

(2) The Minister may accept an application for the renewal of a geothermal licence later than twelve months before, but not in any case after, the date of expiry of the licence.

6. (1) Neither an authority nor a geothermal resources licence issued under the Act shall authorize the applicant to enter upon or exercise any rights in— Exemptions.

(a) any burial ground or land in the vicinity or precincts or any church, mosque or other sacred building or place of worship;

(b) any area situated within fifty metres of any building in use, or any reservoir or dam;

(c) any public road within the meaning of the Public Roads and Roads of Access Act, railways or street within the meaning of the Streets Adoption Act; Cap. 399 Cap. 406.

(d) any area situated within a municipality or township within the meaning of the Local Government Act; Cap. 265.

(e) any land within one thousand metres of the boundaries or any aerodrome under the Civil Aviation Act; Cap. 394.

(f) any area of land declared to be a national park or natural reserve under the Wildlife (Conservation and Management) Act, Cap. 376.

but nothing in this regulation shall be construed as preventing directional drilling into the sub-surface of the areas of land and places specified under this paragraph from adjacent land.

(2) Entry into any area of land or place specified in paragraph (1) shall be subject to the consent of the competent authority.

(3) For the purpose of paragraph 2, "competent authority" means the person or body for the time being empowered under the relevant written law or custom to authorize access to the area of land or place.

(4) Where the Minister is satisfied that entry into any area of land or place in a geothermal resources area is necessary for the carrying out of operations by the applicant for an authority or a geothermal resources licence, he shall produce the consent to such entry of the competent authority or other owner or occupier thereof as the case may be.

7. (1) The following fees payable on applications for an authority under section 6 of the Act and for a geothermal resources licence under section 7 of the Act shall be— Fees, etc.

	Sh.
(a) in respect of an authority	50,000
(b) in respect of a geothermal resources licence ...	120,000

(2) The rents payable under or by virtue of an authority or a geothermal resources licence issued under the Act shall be as set out in the authority or the licence.

(3) The royalties, and other payments payable under or by virtue of a geothermal resources licence shall be as set out in the licence.

Register of authorities, etc.

8. The Minister shall maintain registers of—

(a) geothermal resources areas;

(b) every authority issued under the Act;

(c) geothermal resources licences;

(d) renewals, extensions, surrenders and forfeitures of authorities and licences; and

(e) open geothermal resources areas.

Notification to the Minister.

9. The licensee shall give the Minister thirty days notice of any proposed geophysical survey and drilling, which notice shall contain complete details of the programme to be conducted.

PART III—DRILLING

Drilling.

10. (1) Every bore shall be supervised by a competent representative of the licensee.

(2) The licensee shall maintain a driller's log for each bore.

Notice prior to drilling, etc.

11. (1) The licensee shall not drill a bore or recommence drilling after a six months' cessation without thirty days' prior notification to the Minister, which notice shall set out the reasons for undertaking such bore and shall contain a copy of the driling programme for the bore.

(2) No bore shall, without the consent in writing of the Minister, be drilled so that any part thereof is less than five hundred metres from a boundary of the area covered by an authority.

(3) No licensee shall, except where there is danger or a risk of significant economic loss—

(a) abandon a bore or remove any permanent form of casing therefrom, without giving forty-eight hours prior notification to the Minister; or

(b) commence drilling, re-enter or plug any bore unless a representative of the Minister has been given a reasonable opportunity to be present.

(4) The licensee shall state, in any application to abandon a bore, whether that bore is capable of providing a water supply.

Drilling conditions.

12. All bores drilled shall, unless otherwise authorized by the Minister, comply with the conditions specified in the Second Schedule.

Requirements and conditions for geothermal operations.

13. All geothermal operations shall be conducted in a workman-like manner and comply with the following requirements—

(a) as far as reasonably practicable to—

(i) prevent the unnecessary waste of or damage to geothermal or other energy and mineral resources;

(ii) protect the quality of surface waters, air, and other natural resources, including wildlife, soil, vegetation and natural history;

(iii) protect the quality of cultural resources, including archeological, historical, scenic and recreational resources;

(iv) accommodate other land users;

(v) protect human and wildlife resources from unacceptable levels of noise;

(vi) prevent injury to life; and

(vii) prevent damage to property;

(b) sites selected for the construction of drilling sites, roads, sumps, steam transmission lines and other construction attendant to geothermal operations shall be evaluated for stability and in unstable earth conditions shall be avoided where they could affect the integrity of the facility;

(c) operations shall be conducted in a manner which minimizes erosion and disturbances to natural drainage;

(d) the licensee shall conduct all operations in such manner as to afford reasonable protection of fish, wildlife, and natural habitat.

Confidentiality.

14. (1) Subject to this regulation, all information supplied to the Minister by the licensee shall be kept confidential and shall not be disclosed except with the consent of the licensee, which consent shall not be unreasonably withheld.

(2) Notwithstanding the provisions of paragraph (1), the Minister may use any such information for the purpose of preparing and publishing reports and returns required by law, and for the purpose of preparing and publishing reports and surveys of a general nature.

(3) The Minister may publish any such information which relates to a surrendered area at any time after the surrender; and in any other case three years after giving notice to and hearing representations from the licensee that longer period shall apply.

(4) The Minister shall not disclose, without the written consent of the person supplying it, to any person other than Government advisers, financial institution or donor agencies from which Government may wish to seek funding assistance for geothermal development, and persons employed by or on behalf of the Government any know-how or proprietary technology.

Land exemption for public use.

15. If the Government acquires part of the area covered by an authority or a geothermal resources licence for the public purpose other than for exploring for or exploiting geothermal resources—

(a) such acquired part shall not include any area on which operations are in progress under such authority or licence;

(b) the licensee shall not carry out operations on such acquired part, but may—

(i) enter upon that part but not materially interfere with the public purpose; and

(ii) carry out directional drilling from an adjacent part.

Power to the Minister to inspect geothermal operations.

16. The Minister, or a person authorized by him in writing, may at all reasonable times inspect any geothermal operations and any records of a licensee relating thereto, and the licensee shall provide, where available, facilities similar to those applicable to its own or to its subcontractors' staff for transport to the geothermal operations, subsistence and accommodation expenses and shall pay all reasonable expenses directly connected with the inspection.

Report to the Minister.

17. (1) The holder of an authority to explore shall transmit to the Minister—

(*a*) at latest on the tenth day of every month, a report in respect of the preceding month, specifying—

(i) the progress of operations, the results obtained, events of significance, occurrences, accidents and like matters; and

(ii) the number of persons employed indicating each category; and

(*b*) at the end of each stage of geological or geophysical operations and at the end of every boring operation, a report on that stage of operations together with a copy of the logs relating to the bore.

(2) The holder of a geothermal resources licence shall transmit to the Minister within the first fifteen days of every quarter, a report in respect of the preceding quarter, specifying in respect of each month in the quarter—

(*a*) the quantities of geothermal fluids extracted and any subsequent variations of their physical characteristics;

(*b*) the quantities of geothermal fluids delivered for consumption;

(*c*) the amount of energy transmitted to cables from power stations;

(*d*) the quantities of commercial products, if any, extracted from geothermal fluid, the quantities delivered for consumption and the end of month stocks;

(*e*) all occurrences and accidents; and

(*f*) the number of persons employed indicating each category.

(3) The holder of a geothermal resources licence, being a body corporate, shall transmit to the Minister, in triplicate, and within the month following every annual general meeting, the report of the Board and that of the auditors, the complete statement of accounts relating to the last financial year, and copies of the resolutions, if any, adopted at the meeting.

Site registers.

18. (1) All licensees shall maintain, at the site of works, and present on demand by any person authorized by the Minister—

(*a*) a register of the progress of operations specifying all important matters relating to operations and, in particular, the characteristics of [illegible] the cementation effected, production tests and like matters as well as all occurrences and accidents;

(*b*) geological and geophysical records and logs of all past and current bores; and

(*c*) a record of the physical and chemical characteristics of fluids emitted from past and current bores;

(*d*) a register giving the names of all persons employed; and

(*e*) such other matters as may be prescribed.

(2) The holder of a geothermal resources licence shall, in addition to the matters provided for in subregulation (1), maintain, at the site of works, and present on demand by any inspector, a register of production in which daily entries shall be made of—

(*a*) the quantity of geothermal fluids extracted and their physical characteristics including their temperature, pressure, degree of saturation and other characteristics at the well-head;

(*b*) the quantities and characteristics of geothermal fluids delivered for consumption;

(*c*) the amount of energy transmitted to cables from the power station;

(*d*) the quantities of commercial products, if any, extracted from geothermal fluids; and

(3) A licensee shall cause all borehole cores to be carefully labelled and kept safe from all adverse weather conditions.

FIRST SCHEDULE (r. 3 (1))

MODEL GEOTHERMAL RESOURCES LICENCE

THE GEOTHERMAL RESOURCES ACT, 1982

(*No.* 12 *of* 1982)

AND

THE GEOTHERMAL RESOURCES REGULATIONS, 1990

This geothermal resources licence is granted this .... day of ...., 19... by the Minister of Energy to .... of .... (hereinafter referred as "the licensee).

1. The licensee is hereby granted the following exclusive rights:

(1) The right to enter upon the land specified in the Appendix I ("the licence area") to bore and to extract geothermal resources and to do all such things as are reasonably necessary for the conduct of those operations.

(2) In so far as it may be necessary for and in connection with the said operations, the exclusive rights to—

(*a*) drill and construct all necessary boreholes;

(*b*) erect, construct and maintain houses and buildings for the licensee's own use and for use by the licensee's employees;

(*c*) erect, construct and maintain plant, machinery, buildings and other erections as may be necessary;

(*d*) utilize the geothermal resources;

(*e*) subject to the Water Act, reclaim and utilize any water; and Cap. 372.

FIRST SCHEDULE—(*Contd.*)

(*f*) construct and maintain roads and other means of communication and conveniences.

(3) The exclusive right to take and use or apply the geothermal resources (in accordance with the geothermal contract made between the licensee .... and .... dated the .... day of ...., 19...... ("the geothermal contract")).

2. The rights granted shall be for a term of thirty years from the date hereof and such term may be renewed at the option of the licensee, for two further periods of five years each; provided the licensee has complied with all the terms hereof.

3. The licensee shall pay to the Minister:

(1) Yearly in advance a rental of KSh. .... per hectare for each and every year or part thereof for which this licence is in effect and, if such rent is not paid within three months of becoming due, a penalty of ten per cent shall be payable as if it were part of the rent.

(2) A royalty of a percentage of the value of each kilowatt hour sold by the licensee, such percentage to be negotiated taking into account the expenses incurred by the licensee during the exploration phase.

4. The licensee shall comply with the provisions of the Geothermal Resources Regulations, 1990 and drilling conditions as specified in the Second Schedule thereto.

5. The licensee shall not transfer or assign this licence or any part thereof without the consent of the Minister signified by endorsement hereon, which consent shall not be unreasonably withheld.

6. The Minister may accept the surrender of this licence or any part of the licence area upon such terms and conditions as he may think fit but so, however, that no such surrender shall affect any liability incurred by the licensee before the surrender shall have taken effect.

7. (1) The Minister may, by notice to the licensee, declare this licence to be forfeited—

(*a*) if the licensee wholly ceases work in or under the licence area during a continuous period of six months, without the written consent of the Minister;

(*b*) if the licensee commits a breach or is in default of any provision of the Geothermal Resources Act or of the Geothermal Resources Regulations, 1990 or of any terms or conditions of the licence and the Minister has caused a notice to be served on the licensee requiring the licensee—

(i) in the case of a breach which, in the opinion of the Minister, is capable of being repaired or made good, to repair or make good the breach within a specified period;

FIRST SCHEDULE—(*Contd.*)

(ii) in the case of a breach which, in the opinion of the Minister, is not capable of being repaired or made good, to show cause why this licence should not be forfeited.

(2) The forfeiture of this licence under paragraph (1) shall not affect any liability already incurred by the licensee.

8. (1) Within ninety days of the expiry, surrender or forfeiture of this licence, the licensee may apply to the Minister to enter the licence area to remove the plant, machinery, engine or tools installed or erected thereon.

(2) The Minister may require the licensee to remove the plant, machinery, engines or tools within a rasonable time and if the same are not so removed they may be sold by auction at the risk of the licensee.

(3) The net proceeds of the sale conducted pursuant to paragraph (2) shall be held until applied for by the licensee but may be used in the repair of breaches or faults not made good by the licensee and for payment of the costs incurred in conducting the sale.

9. The licensee shall provide the Minister with periodic written reports of the progress of operations under this licence as follows—

(1) on drilling operations, daily;

(2) on production operations, daily;

(3) on geophysical operations, monthly;

(4) on geothermal operations—

(*a*) within one month of the last day of March, June, September and December covering the previous three months;

(*b*) within three months of the last day of December covering the previous year;

(*c*) within three months of the date of expiry or surrender of this licence.

(5) Each report under paragraph (4) shall contain, in respect of the period which it covers—

(*a*) details of the geothermal operations carried out and the factual information obtained;

(*b*) a description of the area in which the licensee has operated;

(*c*) an account of the licensee's expenditure on geothermal operations;

(*d*) a map indicating all bores and other geothermal operations.

10. The licensee shall pay compensation as required by section 19 of the Act.

11. Where the licensee intends to occupy or disturb the surface of any particular area of private land or to disturb or otherwise interfere with any crops, trees, buildings or works thereon, the licensee shall give not less than twenty-one days notice in writing of his

FIRST SCHEDULE—(Contd.)

intention to the person in visible and immediate occupation of the land affected thereby and, if practicable to the owner of the land, and shall comply with section 20 of the Act.

12. The Minister shall obtain on behalf of the licensee any permit necessary to enable the licensee to use the water in the licence area for the purpose of operations under this licence but the licensee shall not unreasonably deprive the users of land, domestic settlement or cattle watering place of the water supply to which they are accustomed.

13. (1) The Minister may, at the request of the licensee, make available to the licensee such land as the licensee may reasonably require for the conduct of operations under this licence and—

(a) where such land is trust land, the Minister shall procure that Government shall, subject to paragraph (2) of this clause set apart such trust land in the licence area in accordance with the Trust Land Act (Cap. 288) and chapter IX of the Constitution;

(b) where such land is private land, the Minister shall procure that Government acquires the land in accordance with the applicable laws;

(c) the licensee shall pay or reimburse to the Minister any reasonable compensation that may be required for the setting apart, use or acquisition of any land for such operations.

(2) Where the licensee has occupied trust land for the purpose of such operations before that land has been set apart, the licensee shall notify the Minister in writing of the need to set apart such land before the end of the two-year period referred to in section 115 of the Constitution.

(3) The Minister shall procure that the Government shall grant or cause to be granted to the licensee and its contractors and subcontractors such way-leaves, easements, temporary occupation or other permissions within and without the licence area as are necessary to conduct such operations and in particular for the purpose of laying, operating and maintaining pipelines and cables.

(4) The Minister shall procure that the Government shall at all times give the licensee and its contractors and subcontractors the right of ingress to and egress from the licence area to and from, in particular, the facilities whenever located for the conduct of operations under this licence.

14. Subject to the usual national security requirements and the Immigration Act and regulations of Kenya in particular, the Minister shall procure that Government shall not unreasonably refuse to issue and/or renew entry permits for technicians and managers employed in operations under this licence.

15. The Minister shall procure that the licensee and its contractors and subcontractors engaged in carrying out operations under this licence (or the geothermal resources contract) shall be permitted import into Kenya all materials, equipment and supplies including but

FIRST SCHEDULE—(Contd.)

not limited to machinery, vehicles, consumable items, movable property and any other articles, to be used solely in carrying out operations under this licence (or the geothermal resources contract).

(2) The Minister shall procure that such materials, equipment and supplies shall be exempt from all customs duties. However, the licensee and its contractors and subcontractors shall give preference to Kenyan goods and services as long as their prices, quality, quantities and timeliness of delivery are comparable to prices, quality, quantities and timeliness of delivery of non-Kenyan materials, equipment and supplies.

(3) In relation to materials, equipment and supplies imported or to be imported pursuant to subclause (1) of this clause, when a responsible representative of the Ministry has certified that they are to be used solely in carrying out operations under this licence (or the geothermal resources contract), the Minister shall procure that the licensee and its contractors and subcontractors shall be entitled to make such imports without having to obtain—

(a) any approval of import licence, provided, however, that an application has been duly made;

(b) any exchange control approval, subject to the provisions of paragraph 16 hereof; or

(c) any inspection outside Kenya by General Superintendence or other inspecting body, acting for the time being, appointed by the Government.

(4) The Minister shall procure that each expatriate employee of the licensee and its contractors and subcontractors shall be permitted to import and shall be exempt from all customs duties with respect to the reasonable importation of household goods and personal effects, including one automobile, provided, however, that such properties are imported within three (3) months of their arrival or such longer period as the Government may in writing determine.

(5) The Minister shall procure that the licensee and its contractors and subcontractors and their expatriate employees may sell in Kenya all imported items which are no longer needed for operations under this licence (or the geothermal resources contract). However, if such imports were exempt from customs duties, the seller shall fulfil all formalities required in connection with the payment of duties, taxes, fees and charges imposed on such sales.

(6) The Minister shall procure that the licensee and its contractors and subcontractors and their expatriate employees may export from Kenya, exempt of all export duties, taxes, fees and charges, all previously imported items which are no longer required for the conduct of operations under this licence (or geothermal resource contract).

(7) "Customs duties", as that term is used herein, shall include all duties and taxes on imports (except those charges paid to the Government for actual services rendered) which are payable as a result of the importation of the item or items under consideration.

FIRST SCHEDULE—(*Contd.*)

16. (1) As long as the licensee meets its obligations to the Government in terms of tax payments or any other payments contemplated by this licence, and as long as the licensee complies with paragraph (2) of this clause and is not in a material breach of this licence, the Minister shall procure that the Government shall by appropriate legal notice grant, effective upon the date of this licence, the licensee freedom to—

(*a*) open and freely maintain external accounts inside Kenya and foreign bank accounts outside Kenya in accordance with the Exchange Control Notice No. 3 issued under the Exchange Control Act, chapter 113 of the laws of Kenya;

(*b*) receive, retain outside Kenya and freely dispose of foreign currencies received by it outside Kenya, and the licensee shall not be obligated to remit such proceeds to Kenya with the exception of those proceeds as may be needed to meet in Kenya its expenses and payments to the Government;

(*c*) pay directly outside Kenya for purchases of goods and services necessary to carry out operations under this licence (or the geothermal resources contract),

(*d*) pay its expatriate employees working in Kenya in foreign currencies outside Kenya. Such expatriate employees shall be only required to bring into Kenya such foreign exchange as required to meet their personal living expenses and to meet payments of Kenyan taxes;

(*e*) freely repatriate abroad all proceeds from the licensee's geothermal operations in Kenya, including but not limited to proceeds from the sale of assets (proceeds of the geothermal resources contract);

(*f*) have rates of exchange for purchase or sale of currency in Kenya, not less favourable to the licensee than those granted to any investor in Kenya.

(2) In order to keep the Minister and the Central Bank of Kenya informed of its prospective and actual foreign exchange transactions, the licensee shall inform the Minister and the Bank in writing and in such form and detail as the Minister or the Bank may request—

(*a*) of the location of the licensee's bank accounts in Kenya and abroad, which latter accounts shall be opened in banks approved by the Central Bank of Kenya;

(*b*) annually, before the commencement of each calendar year, of the licensee's estimated receipts and disbursements of foreign exchange by principal headings during the year (which statement may be amended from time to time if this appears necessary); and

(*c*) quarterly, within thirty days of the end of each calendar quarter, of the licensee's actual receipts and disbursements of foreign exchange by principal headings during the preceding quarter.

(3) Subject to the obligation to give preference to Kenyan goods as stipulated in this licence, the Minister shall procure that the licensee shall have the right to enter all contracts and subcontracts necessary to carry out operations under this licence (or under the geothermal resources contract), without prior approval by the Central Bank of Kenya or any other Government agency. The Minister reserves the right to inspect the records or documentation related to such contracts and subcontracts. The licensee shall provide a copy of such contracts within thirty days after their execution.

FIRST SCHEDULE—(*Contd.*)

(4) The Minister shall procure that Government shall issue to the licensee a "certificate of approval enterprise" in accordance with the Foreign Investments Protection Act (chapter 518 of laws of Kenya). The amount recognized by the certificate as having been invested shall be the actual amount for the time being invested by the licensee as set forth in its books of account.

17. (1) The licensee shall notify the Minister, before operations begin, of the name and address of the person resident in Kenya who will supervise the operations under this licence and prior notice of any subsequent change shall be given to the Minister.

(2) The licensee shall appoint an attorney resident in Kenya with power of representation in all matters relating to this licence of which appointment the Minister shall be notified before the operations begin, and prior notice of any subsequent change shall be given to the Minister.

18. (1) Where the Minister or the licensee is prevented from complying with this licence by *force majeure*, the party affected shall promptly give written notice to the other and the obligations of the affected party shall be suspended, provided that that party shall do all things reasonably within its power to remove such cause of *force majeure*. Upon cessation of the *force majeure* event, the party no longer affected shall promptly notify the other party.

(2) In this clause, "*force majeure*" means an occurrence beyond the reasonable control of the Minister or of the licensee which prevents either of them from performing their obligations under this licence.

(3) Where the party not affected disputes the existence of *force majeure*, that dispute shall be referred to arbitration in accordance with the provisions for arbitration contained in this licence.

(4) Where an obligation is suspended by *force majeure* for more than one year, the parties may agree to terminate this licence by notice in writing without further obligations.

(5) Subject to paragraph (4) of this clause, the term of the licence shall be automatically extended for the period of the *force majeure*.

19. (1) Except as otherwise provided in this licence, any question or dispute arising out of or in relation to or in connection with this licence shall, as far as possible, be settled amicably. Where no settlement is reached within thirty days from the date of the dispute, such dispute shall be referred to arbitration in accordance with the provisions hereinafter contained.

FIRST SCHEDULE—(*Contd.*)

(2) The Minister on behalf of the Government of Kenya and the licensee hereby consent to submit to the International Centre for the Settlement of Investment Disputes all disputes arising out of this licence or relating to any investment made under it for settlement by arbitration pursuant to the Convention on the Settlement of Investment Disputes between States and Nations of other States ("the Convention").

(3) It is hereby stipulated that the licensee is a national of .... and that this licence is an investment within the meaning of the Convention.

(4) Any such arbitration proceeding shall be conducted in accordance with the Rules of Procedure for Arbitration Proceedings in effect on the date on which the proceeding is instituted.

APPENDIX I

DELINEATION OF LICENCE AREA

The licence area shall be all those certain lands more particularly described in Appendix I and shown on the map set forth in Appendix II.

SECOND SCHEDULE (r. 12)

CONDITIONS FOR DRILLING OF BORES

The following conditions are intended as guidelines to ensure safety and environmental integrity. If these conditions would prove too restrictive for economical geothermal energy recovery, the licensee may propose an alternative.

1. All casing strings reaching the surface shall be cemented at a sufficient depth to provide adequate anchorage and support for the casing and any blowout prevention equipment required thereon. The several casing strings in order of installation are—

(*a*) surface;

(*b*) intermediate;

(*c*) anchor;

(*d*) production strings.

(2) The following casing setting depth requirements are general in nature and subject to variation to permit the casing (if any) to be set and cemented in competent formation. Casing setting depths shall be based upon all geologic and engineering factors including apparent geothermal gradients, depths and pressures of the various formations to be penetrated and all other pertinent information about the area. All depths in these regulations referred to True Vertical Depth (T.V.D.) below ground level, unless otherwise specified:

(*a*) *Surface Casing.*—This casing shall be set at a minimum depth of 30 metres and a maximum depth of 60 metres before

SECOND SCHEDULE—(*Contd.*)

drilling into shallow formation suspected or known to contain geothermal resources, non-condensible gases, or other mineral resources or upon encountering such formations.

(*b*) *Intermediate Casing.*—This casing shall be set at any time when required by bore conditions encountered in drilling below the surface casing such as anomalous pressure zones, uncased fresh water aquifers, caveins, washouts, lost circulation zones, rapidly increasing thermal gradients or other drilling hazards.

(*c*) *Anchor Casing.*—This casing shall be set at a depth equivalent to or in excess of 10 per cent of the proposed total depth of the bore provided, however, that such setting depth shall be not less than 250 metres nor more than 400 metres.

(*d*) *Production Casing.*—This casing may be set at the top of or through the potential producing zone and shall be set before completing the bore for production. Production casing shall be run to the surface or lapped into the next larger casing string. If a liner is used, the lap shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger casing string has been achieved. The liner overlap shall be minimum of 30 metres. The test shall be recorded on the driller's log. In the event of lap or casing failure during the test, the lap or casing must be repaired or recemented and successfully retested as required. Production casing shall normally be of consistent nominal outside diameter from the surface or from the top of the lap to the casing shoe. The surface casing shall not be used as production casing.

3. (1) The surface, intermediate and anchor casing strings shall be cemented with a quantity of cement sufficient to fill the annular space back to the surface. Production casing shall be cemented with a high temperature resistant admix and shall be cemented in a manner necessary to exclude, isolate or segregate overlying formation fluids from the geothermal resources zone and to prevent the movement of fluids into possible fresh water zones. The first stage of all cementing operations must be carried out by circulating cement from the surface to the bottom of the casings and back up the annulus. Cementing of casing.

(2) Before any backfill cementing is carried out the casing annulus must be tested to prove cement can pass below the outer casing shoe so as not trap water or explosive fluid in the annulus.

(3) Production casing shall be cemented back to the surface or, if lapped, to the top of the lap. A temperature or cement bond log may be required by the Minister after setting and cementing the production casing and after all primary cementing operations if an unsatisfactory cementing job is indicated.

4. (1) Prior to drilling out the casing shoe after cementing, all casing strings set to a depth of 152 metres or greater, shall be pressure tested to a minimum pressure of 69 bars (1,000 p.s.i.) or 0.045 bars/metre (0.2 p.s.i./ft.) whichever is greater. Pressure testing of casing.

SECOND SCHEDULE—(*Contd.*)

(2) All casing strings set at a depth less than 152 metres (500 feet), shall be pressure tested to a minimum pressure of 20 bars (300 p.s.i.).

(3) The tests under paragraphs (1) and (2) shall not exceed the rated working pressure of the casing or the blowout preventer stack assembly, whichever is lesser and in the event of casing failure during the test, the casing must be repaired or recemented until a satisfactory test is obtained.

(4) A pressure decline of 10 per cent or less in 30 minutes shall be considered satisfactory.

(5) Casing test results shall be recorded on the driller's log. Advance notice of all casing and lap tests shall be given in sufficient time to enable the Minister or his representative to be present to witness such tests. The casing and lap test reports shall give a detailed description of the test, including mud and cement volumes, lapse of time between running and cementing casing and testing, method of testing and test results.

Well survey.

5. (1) Deviation surveys (inclination from vertical or single shot) shall be taken on all bores during the normal course of drilling at intervals not exceeding 152 metres and in calculating all surveys, a correction from true north to Labert-Grid north shall be made after making the magnetic to true north correction.

(2) Bores are considered vertical if inclination does not exceed an average of five degrees from the vertical.

(3) Bores are considered directional if inclination exceeds an average of five degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 30 metres between stations prior to, or upon, setting any casing string or liner (except conductor casing) and at total depth.

Safety equipment and procedures.

6. All necessary precautions shall be taken to keep all bores under control at all times, utilize trained and competent personnel, and utilize properly maintained equipment and materials. Blowout preventers and related bore control equipment shall be installed, tested immediately thereafter and maintained ready for use until drilling operations are completed. Certain components, such as packing elements and ram rubbers, shall be of high temperature resistant materials as necessary. All kill lines, blowndown lines, manifolds and fittings shall be steel and shall have a temperature derated minimum working pressure rating equivalent to the maximum anticipated wellhead surface pressure. Except as otherwise provided by these regulations, blowout prevention equipment shall have manually operated gates and hydraulic actuating systems and accumulators of sufficient capacity to close all of the hydraulically-operated equipment and have a minimum pressure of 69 bars (1,000 p.s.i.) remaining on the accumulator. Dual control stations shall be installed with a high pressure backup system. One control panel shall be located at the driller's station and one control panel shall be located on the ground at least 15 metres away from the wellhead or rotary table. Air or other gaseous fluids drilling systems shall have blowout prevention

SECOND SCHEDULE—(*Contd.*)

assemblies. Such assemblies may include, but are not limited to, a rotating head, a double ram blowout preventer or equivalent, a banjo-box or an approved substitute therefor and a blind ram blowout preventer or gate valve, respectively.

Requirement for drilling.

7. (1) *Surface casing.*—Before drilling below this string, at least—

(*a*) one remotely controlled hydraulically-operated expansion type preventer; and

(*b*) a manual and remotely controlled complete shut-off single ram blowout preventer or equivalent having a temperature derated minimum working pressure rating which exceeds the maximum anticipated surface pressure at the anticipated reservoir fluid temperature. At least one ram set shall be for complete shut off. A drilling spool with side outlets or equivalent, shall be installed. A kill line and blowdown line with appropriate fittings shall be connected to the drilling spool.

(2) *Anchor, intermediate and production casings.*—Before drilling below the blowout prevention equipment shall include a minimum of—

(*a*) one expansion-type preventer and accumulator;

(*b*) a manual and remotely controlled hydraulically-operated double ram blowout preventer or equivalent having a temperature derated minimum working pressure rating which exceeds the maximum anticipated surface pressure at the anticipated reservoir fluid temperature;

(*c*) a drilling spool with side outlets or equivalent;

(*d*) a kill line equipped with at least one valve; and

(*e*) a choke line equipped with at least one valve and securely anchored at all bends and at the end.

(3) *Testing and maintenance.*—Ram-type blowout preventer and auxiliary equipment shall be tested to a minimum of 69 bars (1,000 p.s.i.) or to the working pressure of the casing or assembly, whichever is the lesser. Expansion-type blowout preventer shall be tested to 70 per cent of the above pressure testing requirements; and the blowout prevention equipment shall be pressure tested—

(*a*) when installed;

(*b*) prior to drilling out plugs and casing shoes;

(*c*) not less than once each week, alternating the control stations; and

(*d*) following repairs that require disconnecting a pressure seal in the assembly.

(4) During drilling operations, blowout prevention equipment shall be actuated to test proper functioning as follows—

(*a*) once each trip for blind and pipe rams but not less than once each day for pipe rams; and

(*b*) at least once each week on the drill pipe for expansion type preventers.

SECOND SCHEDULE—(*Contd.*)

(5) All flange bolts shall be inspected at least weekly and re-tightened as necessary during drilling operations. The auxiliary control systems shall be inspected daily to check the mechanical condition and effectiveness and to ensure personnel acquaintance with the method of operation. Blowout prevention and auxiliary control equipment shall be cleaned, inspected and repaired, if necessary, prior to installation to assure proper functioning. Blowout prevention controls shall be plainly labelled, and all crew members shall be instructed on the function and operation of such equipment. A blow-out prevention drill shall be conducted weekly for each drilling crew. All blowout prevention tests and crow drills shall be recorded on the driller's log.

(6) *Related well control equipment.*—At least one non-return valve shall be installed in the drill string at all times.

Drilling fluid.

8. (1) The properties, use and testing of drilling fluids and the conduct of related drilling procedures shall be such as are reasonably necessary to guard against the blowout of any bore. Sufficient drilling fluid materials to ensure bore control shall be maintained in the field area readily accessible for use at all times; and—

(*a*) before pulling drill pipe, the drilling fluid shall be properly conditioned or displaced. The hole shall be kept reasonably full at all times. Mud cooling techniques shall be utilized when necessary to maintain mud characteristics for proper bore control and hole conditioning;

(*b*) mud testing and treatment consistent with good operating practice shall be performed daily or more frequently as conditions warrant. Mud testing equipment shall be maintained on the drilling rig at all times.

(2) The following drilling fluid system monitoring or recording devices shall be installed and operated continuously during drilling operations with mud, occurring below the shoe of the conductor casing—

(*a*) high-low level mud pit indicator including visual audio-warning device;

(*b*) desilters and desanders;

(*c*) a mechanical, electrical or manual surface drilling fluid temperature monitoring device. The temperature of the drilling fluid going into and coming out of the hole shall be monitored, read and recorded on the driller's or mud log for a minimum of every 9 metres of hole drilled below the conductor casing; and

(*d*) a hydrogen sulphide indicator and alarm shall be installed in areas suspected or known to contain hydrogen sulphide gas which may reach levels considered to be dangerous to the health and safety of personnel in the area.

(3) From the time drilling operations are initiated and until the bore is completed or abandoned, a member of the drilling crew or the tool pusher shall monitor the rig floor at all times for surveillance purposes, unless the bore is secured with blowout preventers or cement plugs.

SECOND SCHEDULE—(*Contd.*)

Bore logging.

9. All bores shall be logged from total depth to the shoe of the conductor casing.

Wellhead equipment and testing.

10. (1) All wellhead connections shall be fluid pressure tested to the appropriate working pressure rating. Cold water is recommended as the testing fluid. Welding of well head connections shall be performed using materials in conformity with industrial standards.

(2) All completed bores shall be equipped with a minimum of one casing head with side outlets, one master valve and one production valve.

(3) All casing heads, christmas trees, fittings and connections shall have all temperature derated working pressure equal to or greater than the pressure of saturated steam at reservoir temperature.

(4) Packing, sealing mediums and lubricants shall consist of materials or substances that function effectively at, and are resistant to, high temperatures. Casing head connections shall be made such that fluid can be pumped between casing strings.

(5) Any bore showing sustained casing head pressure or leaking of geothermal fluids between casing strings shall be tested to determine the origin of the failure, when such failure point is not otherwise determined, and corrective measures shall be taken.

Bore spacing, plugging and permanent abandonment.

11. (1) No producing interval of any bore shall be located within 30 metres or the outer boundaries of the licence area.

(2) All bores not in use or demonstrated to be potentially useful shall be promptly plugged in the following manner—

(*a*) cement used to plug any geothermal resources bore, except that cement or concrete used for surface plugging, shall be placed in the hole by pumping through drill pipe or tubing, and the cement shall consist of a high temperature resistant admix;

(*b*) (i) in uncased portions of bores, cement plugs shall be placed to protect all subsurface mineral resources including fresh water aquifers; and plugs shall extend a minimum of 30 metres below, if possible, and 30 metres above such aforementioned zones. Cement plugs shall be placed in a manner necessary to isolate formations and to protect the fluids in such formations from interzonal migration or contamination;

(ii) where there is an open hole (uncased and open into the casing string above) a cement plug shall be placed in the deepest casing string by either (*a*) or (*b*) below. In the event that lost circulation conditions exist or are anticipated, or if the well has been drilled with air or other gaseous substance, the plug shall be placed in accordance with (*c*) below;

SECOND SCHEDULE—(*Contd.*)

(iii) a cement plug shall be placed across the shoe extending a minimum of 30 metres above and 30 metres (100 feet) below; or

(iv) a cement retainer with effective back pressure control set approximately 30 metres above the casing shoe with at least 61 metres of cement below the retainer and 30 metres cement above;

(v) a permanent bridge plug set at the casing shoe and capped with a minimum of 61 metres of cement.

(*c*) A cement plug shall be placed across production perforations, extending 30 metres below (where possible) and 30 metres above the perforated interval. When a cement retainer is used to squeeze cement in to the perforated intervals, the retainer shall be set a minimum of 30 metres above the perforations. Where the casing contains perforations at or below fish, junk or collapsed casing, thereby preventing clean-out operations, a cement retainer shall be set at least 30 metres above such point, and the interval below the retainer shall be squeeze cemented.

(*d*) A cement plug shall be placed across all casing stubs, laps, liner tops and all casing shoes not protected by an inner casing string. Such plug shall extend a minimum of 15 metres below and 15 metres above any such shoe, stub, lap or liner top.

(*e*) All open annuli extending to the surface shall be plugged with cement.

(*f*) The innermost casing string which reaches ground level shall be cemented or concreted to a minimum depth of 15 metres measured from 2 metres below ground level.

(*g*) The hardness and location of cement plugs placed across perforated intervals and at the top of uncased or open hole shall be verified by setting down with tubing or drill pipe a minimum of 6,083 kilograms weight on the plug or the maximum weight of the available tubing or drill pipe string, if less than 6,803 kilograms.

(*h*) The intervals of the bore not filled with cement shall be filled with good quality heavy mud.

(*i*) All casing strings shall be cut off at least 2 metres below ground level and capped by welding a steel plate on the casting stub. Collars, pads, structures and other facilities shall be removed.

(*j*) An incomplete drilling bore that is to be temporarily abandoned shall be mudded and cemented as required hereinabove for permanent abandonment except for the provisions of subparagraphs (*e*), (*f*) and (*g*).

(*k*) The drilling equipment shall not be removed on any geothermal resources bore where drilling operations have been suspended, either temporarily or indefinitely, until appropriate measures have been taken to close the well and to

SECOND SCHEDULE—(*Contd.*)

protect all sub-surface resources, including fresh water aquifers.

(12) (*a*) The licence shall remove or store, in an orderly manner, all materials not in use, and shall provide and use pits and sumps of adequate capacity and designed to retain materials and fluids necessary for drilling, production, or other operations. When no longer needed, pits and sumps are to be properly abandoned and the land restored. Waste.

(*b*) Liquid well effluent or the liquid residue thereof containing substances, including heat, which may be harmful or injurious to persons or property shall be dealt with in such a way as to minimize such possible harm or injury.

(*c*) Drill cuttings, sand, precipitates and other similar solids shall be disposed of in suitable manner.

Made on the 24th April, 1990.

K. N. K. BIWOTT,
Minister for Energy.

LEGAL NOTICE NO. 207

THE REGULATION OF WAGES AND CONDITIONS OF EMPLOYMENT ACT

(*Cap.* 229)

IN EXERCISE of the powers conferred by section 11 of the Regulation of Wages and Conditions of Employment Act, the Minister for Labour makes the following Order:—

THE REGULATION OF WAGES (GENERAL) (AMENDMENT) ORDER, 1990

1. This Order may be cited as the Regulation of Wages (General) (Amendment) Order, 1990 and shall come into operation on the 1st June, 1990.

2. The Regulation of Wages (General) Order, 1982 is amended by deleting the First and Second Schedules thereto and inserting the following new Schedules— L.N. 120/82, L.N. 80/85, L.N. 122/87, L.N. 189/89.

The Geothermal Resource Regulations

Appendix VI

THE GEOTHERMAL RESOURCES ACT, 1982

No. 12 of 1982

Date of Assent: 8th July, 1982

Date of Commencement: By notice

ARRANGEMENT OF SECTIONS

An Act of Parliament to control the exploitation and use of geothermal resources and vest the resources in the Government and to provide for connected purposes

ENACTED by the Parliament of Kenya as follows:—

PART I—PRELIMINARY

Short title and commencement.

1. This Act may be cited as the Geothermal Resources Act, 1982, and shall come into operation on such day as the Minister may, by notice in the Gazette, appoint.

Interpretation.

2. In this Act, unless the context otherwise requires—

"bore" means a well, hole, pipe or excavation of any kind which is bored, drilled, sunk or made in the ground for the purpose of investigating, prospecting for, obtaining or providing geothermal resources; and includes any reactivated or converted bore previously capped and abandoned which is employed for re-injecting geothermal resources or their residues;

"geothermal resources" means any product derived from and produced within the earth by natural heat; and includes steam, water and water vapour and a mixture of any of them that has been heated by natural heat whether as a direct product or resulting from other material introduced artificially into an underground formation and heated by natural heat;

"geothermal resources area" means an area which is declared to be a geothermal resources area under section 4;

"land" includes land covered with water;

"licence" means a geothermal resources licence granted under section 7;

"licensee" means the public or local authority, company or body of persons to whom a licence is granted.

"the Minister" means the Minister for the time being responsible for matters connected with energy;

3. All unextracted geothermal resources under or in any land shall be vested in the Government subject to any rights which, by or under any written law, have been or are granted or recognized as being vested in any other person.

Geothermal resources vested in the Government.

4. The Minister may, by notice in the Gazette, declare that any area of land where geothermal resources have been discovered or which is a source or is believed to be a source of geothermal resources shall be a geothermal resources area.

Declaration of geothermal resources area.

5. Notwithstanding anything to the contrary in any written law or instrument of title, no person shall sink a bore, tap or take and use or apply geothermal resources for any purpose unless he is first granted an authority or licence under this Act.

Unauthorized use of geothermal resources prohibited.

PART II—EXPLOITATION OF GEOTHERMAL RESOURCES

6. (1) For the purposes of and subject to this Act, the Minister may authorize any person (including a public officer), in writing, to make surveys, investigations, tests and measurements in search of geothermal resources and for that purpose the authorized person may—

Minister to authorize search for geothermal resources.

(*a*) enter upon any land specified in the authority with such assistants, gear, appliances, and equipment as he thinks fit;

(*b*) sink any bore on the land;

(*c*) make geological surveys and geophysical surveys on the land; and

(*d*) generally do all things necessary in connection with the survey, investigation, test or measurement.

(2) When practicable, reasonable notice of the intention to enter upon any land shall be given to the owner or occupier of the land.

(3) Every person who is authorized in writing under subsection (1) to enter upon any land shall produce his authority when required to do so by the owner or occupier of the land on which he intends to enter or has entered.

(4) Every authority granted under this section shall be subject to—

(a) the condition that every bore made pursuant to the authority shall be—

(i) kept under close supervision;

(ii) maintained in a safe condition;

(iii) finally left in a condition of lasting safety;

(b) such other conditions as the Minister may impose either at the time of granting the authority or subsequently at the time of the closure of the bore.

(5) An authority granted under this section shall not be transferable, and shall be in force for a period of one year from the date of issue, but may be renewed for a period of one year from the date of expiration thereof or from the expiration of any renewal.

(6) An authority granted under this section may be revoked by the Minister on any of the following grounds—

(a) that the person to whom the authority is granted has not complied with any requirement or condition of his authority;

(b) that operations being carried on under the authority are, in the opinion of the Minister, affecting detrimentally other specified bores or the supplies of geothermal resources for other specified purposes;

(c) that it is in the public interest that operations being carried on under the authority should cease.

Minister may grant a geothermal resources licence.

7. (1) The Minister may, on application being made to him in respect of any land, grant a licence (to be known as a "geothermal resources licence") over part or the whole of a geothermal resources area under such terms and conditions as he may determine.

(2) An application for a licence to be issued under this section shall be in the approved form and be accompanied by the prescribed fees.

(3) A licence may be granted under this section for such term, not exceeding thirty years, as the Minister may determine and shall be in the prescribed form.

8. (1) A licence shall, subject to this Act, confer upon the licensee the right— Rights under licence.

(*a*) to enter upon the land being the subject of the licence to bore and to extract geothermal resources and to do all such things as are reasonably necessary for the conduct of those operations;

(*b*) in so far as it may be necessary for and in connection with the operations referred to in paragraph (*a*)—

(i) to drill and construct all necessary boreholes;

(ii) to erect, construct and maintain houses and buildings for his own use and for use by his employees;

(iii) to erect, construct and maintain plant, machinery, buildings and other erections as may be necessary;

(iv) to utilize the geothermal resources;

(v) subject to the Water Act, to reclaim and utilize any water; and Cap. 372.

(vi) to construct and maintain roads and other means of communications and conveniences;

(*c*) to take and use or apply the geothermal resources for any purpose specified in the licence.

(2) Where any by-product obtained in the production of geothermal resources may be reclaimed for further use or sale and is a mineral within the meaning of the Mining Act, the licence may be modified so as to allow for the inclusion of a mining lease to enable recovery of that by-product. Cap. 306.

9. The Minister may— Renewal and surrender of licence, etc.

(*a*) renew a licence for a term not exceeding five years subject to such terms and conditions as he thinks fit;

(*b*) wholly or partly remit all or any of the terms and conditions contained in any licence where, owing to special circumstances, in his opinion, compliance therewith would be impossible or great hardship would be inflicted upon the licensee;

(c) extend time to the licensee for complying with the terms and conditions of any licence upon such terms and conditions as he may think fit;

(d) accept, whether with a view to the renewal or re-grant of any licence or otherwise the surrender of any licence or any part of the area comprised therein upon such terms and conditions as he may think fit, but so however that no such surrender shall affect any liability incurred by the licensee before the surrender shall have taken effect.

Transfer of licence.

10. The licensee shall not transfer or assign his licensee or any part thereof without the consent in writing of the Minister signified by endorsement thereon.

Forfeiture of licence.

11. (1) The Minister may, by notice to the licensee, declare a licence to be forfeited—

(a) if the licensee wholly ceases work in or under the land the subject of the licence during a continuous period of six months, without the written consent of the Minister;

(b) if the licensee commits a breach or is in default of any provision of this Act or of the regulations made thereunder or of any terms or conditions of the licence and the Minister has caused a notice to be served upon the licensee requiring him—

(i) in the case of a breach which, in the opinion of the Minister, is capable of being repaired or made good, to repair or make good the breach within a speficied period;

(ii) in the case of a breach which, in the opinion of the Minister, is not capable of being repaired or made good, to show cause within a specified period why his licence should not be forfeited.

(2) The forfeiture of a licence under subsection (1) shall not affect any liability already incurred by the licensee.

(3) The forfeiture of a licence under subsection (1) shall be published in the Gazette.

Rent and penalty for non-payment of rent.

12. The licensee shall in respect of his licence pay yearly in advance such rent as may be prescribed by the Minister and, if the rent is not paid within three months of becoming due a penalty of ten per centum shall be payable as if it were part of the rent.

Licensee to re-enter under certain conditions.

13. (1) Any licensee whose licence has expired or has been surrendered or forfeited may, within ninety days of the date of the expiry, surrender or forfeiture, apply to the Minister to enter the land which was comprised in the licence to remove the plant, machinery, engines or tools installed or erected on the land.

(2) The Minister may require the licensee to remove the plant, machinery, engines or tools within a reasonable time, and if the plant, machinery, engines or tools are not removed within a reasonable time they may be sold by auction at the risk of the licensee.

(3) The net proceeds of the sale conducted pursuant to subsection (2) shall be held until applied for by the licensee but may be used in the repair of breaches or faults not made good by the licensee and for the payment of the costs incurred in conducting the sale.

Power of licensee in respect of the generation of electricity Cap. 314

14. The holder of a licence under the Electric Power Act may for the purpose of generating, transmitting or supplying electrical power—

(a) extract, take, use and apply geothermal resources on or under any land which is the subject of the licence;

(b) erect, construct, provide and use such works and appliances as may be necessary for the purpose of generating electricity, and in connection with the transmission, use, supply and sale of electricity.

Authorities, etc. to be registered

15. Every authority and licence issued under this Act shall be registered in the prescribed manner.

PART III—SAFETY AND ACCIDENTS

Safety of persons

16. A licensee shall be liable for any loss, damage or injury to any person or property resulting from his works or operations, whether as a result of negligence or otherwise.

Minister may require bore to be closed.

17. (1) Notwithstanding any other provisions of this Act, the Minister may, at any time, order a bore to be closed after giving notice to any person in accordance with subsection (2) on any of the following grounds—

(a) that the bore is a source of danger to persons or property in the vicinity;

(b) that the bore is, in the opinion of the Minister, affecting detrimentally other specified bores or a specified tourist attraction or the supplies of geothermal resources for other specified purposes;

(c) that the bore is a nuisance in law or that it is otherwise in the public interest that the bore should be closed;

(d) that the bore is no longer necessary for operation in accordance with plans approved by him;

(e) for the protection of the environment including ground water against contamination; or

(f) in the interest of conservation of the geothermal resources.

(2) Notice to close a bore may be given under this section by the Minister to the licensee entitled to use or apply the geothermal resources from the bore for any purpose and if there is no licence granted under this Act the notice may be given to any of the following—

(a) the person authorized by the Minister to make the bore;

(b) a person who made or assisted to make the bore without any authority;

(c) the owner of the land if he permitted the bore to be made without the authority of the Minister.

(3) No compensation resulting from the closure of any bore shall be payable by the Government but the Minister may consider the refund of part of the fees which may have been paid in respect of any authority or licence in relation to a bore which he has ordered to be closed under this section, except that no refund of any part of fees shall be made in respect of any bore made wihout the authority of the Minister.

PART IV—MISCELLANEOUS PROVISIONS

Compensation for injury or damage to land.

18. (1) Except as otherwise provided in this Act every person who—

(*a*) has an interest in any land injuriously affected by the exercise of any of the powers conferred by this Act or conferred by any authority or licence granted under this Act; or

(*b*) suffers any damage from the exercise of any powers so conferred,

shall be entitled to compensation, determined by the Minister, for the loss, injury and damage sufferred by him.

(2) Any person aggrieved by a determination of the Minister under subsection (1) may appeal against such determination to the High Court.

Payment of compensation to land owners and occupiers.

19. (1) Whenever, in the course of searching or boring for geothermal resources, any disturbance of the rights of the owner or occupier of any land or a nuisance or damage to that land or to any crops, trees, buildings, stock or works thereon is caused, the holder of the authority or licence under which such operations are carried out shall pay to the owner or occupier a fair and reasonable compensation for such disturbance, nuisance or damage.

(2) If the person referred to in subsection (1) fails to pay compensation or if an owner or occupier is dissatisfied with the compensation offered to him, the owner or occupier may within one month of the demand having been made refer the matter to the High Court which shall assess and determine the amount of compensation to be paid.

Notice in respect of private land

20. (1) Where a licensee intends to occupy or disturb the surface of any particular area of private land or to disturb or otherwise interfere with any crops, trees, buildings or works thereon, he shall give not less than twenty-one days notice in writing of his intention to the person in visible and immediate occupation of the land affected thereby and, if practicable, to the owner of the land.

(2) When the occupation, disturbance or interference referred to in subsection (1) has continued for a period of thirty consecutive days, the owner or occupier of the land affected may require the licensee to give security, in such sum and by such means as the Minister may direct, for meeting any compensation payable under section 19 to the owner or occupier of the land.

(3) In this section "owner" means—

(a) in case of trust land the county council in which the land is vested;

Cap. 287.

(b) in the case of land owned by group representatives under the Land (Group Representatives) Act, that group;

(c) in the case of other land, the registered owner, lessee or grantee.

(4) In the case of land owned by group representatives under the Land (Group Representatives) Act, the notice required under subsection (1) to be given to the owner of the land may be sent by post addressed to the postal address of the group representatives or delivered personally to the office of that group.

Charges payable for extraction of geothermal resources for certain puposes.

21. The Minister shall levy the prescribed fees, rentals and royalties for the extraction of geothermal resources for industrial or commercial purposes and for any other purposes which may be determined by the Minister

Offences.

22. (1) Every person who sinks any bore or who extracts, takes, uses or applies geothermal resources in contravention of this Act shall be guilty of an offence.

(2) Every person who removes, damages, destroys or otherwise interferes with any survey pegs or beacons placed on the ground in connection with any survey lawfully carried on under this Act or any valve or instrument being used in connection with any such survey or with any bore shall be guilty of an offence.

Penalties.

23. Any person who is guilty of an offence under this Act shall be liable to a fine not exceeding ten thousand shillings and if the offence is a continuing one, to a further fine not exceeding one thousand shillings for every day or part of a day during which the offence continues.

24. (1) The Minister may make regulations necessary for carrying into effect the provisions of this Act. Regulations.

(2) Regulations may be made under this section for the following purposes—

(*a*) prescribing any forms that may be required for the purposes of this Act;

(*b*) prescribing conditions upon or subject to which authorities and licences may be applied for, granted or renewed;

(*c*) providing for the keeping of records and the furnishing of information and returns by persons authorized by or under this Act, and prescribing the nature of the records, information, and returns and the form, manner and time in which they shall be kept or furnished;

(*d*) prescribing matters in respect of which fees, rents and royalties are to be payable under this Act and the amount of the fees and rents, and persons liable to pay them;

(*e*) authorizing the refund of fees, rents or remission, in such circumstances as the Minister thinks fit, of any fees or rentals payable under this Act;

(*f*) prescribing the responsibilities of licensees and persons to whom authorities are granted by or under this Act, and the operations to be carried out under licences;

(*g*) prescribing the qualifications of persons in charge of the making and closing of bores, and in particular, of persons employed as bore managers, and providing for the examination of any grant of certificates to qualified persons.

(*h*) preventing or abating nuisances in or about bores and industries using geothermal resources;

(*i*) prescribing safety precautions in the making and after the completion of bores, and the treatment of the ground above any bore and of water above and below the ground, and preventing waste or loss of geothermal resources;

(*j*) prescribing drilling machinery, materials, and casting to be used in making of bores and to be available to cope with any emergency in connection with any bore, and prohibiting the use of other classes of materials thereof;

(*k*) prohibiting or regulating the making of bores near other bores;

(*l*) regulating the cessation of boring operations and the abandonment and closing of bores and prescribing precautions against loosening the earth in the vicinity of any bore;

(*m*) providing for bores to be made with due diligence and by safe and satisfactory methods;

(*n*) generally regulating the making of bores;

(*o*) providing for the exemption of licensees and persons to whom authorities have been granted under this Act, either wholly or partially, and either absolutely or conditionally, from any of the requirements of their licences or authorities or of regulations made under this section.

Kenya Electric Power Act

Appendix VII

Note: Kenya Electric Power Act

The Geothermal Resources Act 1982 states *inter alia* that the holder of a geothermal resources' license may "take and use or apply the geothermal resources for any purpose specified in the license.[1] The Act further states that the holder of a license under the Electric Power Act "may for the purpose of generating, transmitting or supplying electrical power ... erect such facilities as necessary for the purpose of generating, transmitting and selling electricity."[2] The Geothermal Resources Regulation 1990 further provides in its first schedule (the Model Geothermal Resources Licenses) that exclusive right to "take and use or apply" the geothermal resources shall be in accordance with the geothermal contract made between the licenses and such other parties to the contract.[3]

It is within the context of this geothermal resources legal, regulatory and contractual system that the issue arises of how a geothermal licensee is permitted to generate electrical power. Pursuant to the terms of the Geothermal Resources Act, in order for the geothermal resources licensee to be able to generate, transmit or supply electrical power a license under the Electric Power Act[4] must be issued.

The Electric Power Act provides that in order for a public or local authority, company, person, or body of persons to generate electricity, such entity must hold a bulk supply license or a local generating license under this Act.[5] The Act also provides for exceptions to the licensee rules which are not pertinent in the instant matter.[6]

1/ The Geothermal Resources Act 1982, Laws of Kenya, Law No. 12 1982, § 8(1)(c).

2/ *Id.* § 14.

3/ The Geothermal Resources Regulation, 1990, Legal Notice 206, April 24, 1990, Model Geothermal Resources License, § 1(3).

4/ Electric Power Act, Ch. 314, Laws of Kenya 2-213 (1986).

5/ *Id.* § 4(1).

6/ *Id.* § 4(1) to (4).

Two types of licenses may be issued: a bulk supply license and a local generating license.

The Minister of Energy may grant a bulk supply license to any company to supply electrical energy in bulk to bulk supply licensees or authorized distributors within any area prescribed in such license.[7/] Such a bulk supply license under this Act conveys to the licensee the right to generate, transmit and supply electrical energy over, through or within the area defined by the license.[8/] Such license may be for any period not exceeding 50 years.[9/]

A "bulk supply license" means a license granted to a public or local authority, company, person or body of persons to generate and supply electrical energy to other bulk supply licensee or authorized distributors within a defined area. The bulk supply license is in contrast to a "local generating license" which basically is a license authorizing an authorized distributor to generate electrical energy. The local generating license is issued by the Minister of Energy after determining that the holder of the distributing license cannot obtain a supply of electrical energy from a bulk supply licensee, or that the distributing licensee will be able to generate electrical energy at the lowest price at which such electrical energy could be supplied by a bulk supply licensee.[10/]

Thus, the geothermal resources licensee will most likely be required to obtain a bulk supply license to generate and sell electricity.

7/ Id. § 10(1).

8/ Id. § 10(5).

9/ Id. § 10(2).

10/ Id. § 2.

The Constitution of Kenya, Article 75

Appendix VIII

of the sentence or order of a court, is reasonably necessary in the interests of hygiene or for the maintenance of the place at which he is detained;

(*c*) labour required of a member of a disciplined force in pursuance of his duties as such or, in the case of a person who has conscientious objections to service as a member of an armed force, labour that that person is required by law to perform in place of such service;

(*d*) labour required during a period when Kenya is at war or an order under section 85 is in force or in the event of any other emergency or calamity that threatens the life or well-being of the community, to the extent that the requiring of the labour is reasonably justifiable, in the circumstances of a situation arising or existing during that period or as a result of that other emergency or calamity, for the purpose of dealing with that situation; or

(*e*) labour reasonably required as part of reasonable and normal communal or other civic obligations.

Protection from inhuman treatment.

74. (1) No person shall be subject to torture or to inhuman or degrading punishment or other treatment.

(2) Nothing contained in or done under the authority of any law shall be held to be inconsistent with or in contravention of this section to the extent that the law in question authorizes the infliction of any description of punishment that was lawful in Kenya on 11th December, 1963.

Protection from deprivation of property. 13 of 1977, s. 3.

75. (1) No property of any description shall be compulsorily taken possession of, and no interest in or right over property of any description shall be compulsorily acquired, except where the following conditions are satisfied—

(*a*) the taking of possession or acquisition is necessary in the interests of defence, public safety, public order, public morality, public health, town and country planning or the development or utilization of property so as to promote the public benefit; and

(*b*) the necessity therefor is such as to afford reasonable justification for the causing of hardship that may result to any person having an interest in or right over the property; and

(*c*) provision is made by a law applicable to that taking of possession or acquisition for the prompt payment of full compensation.

(2) Every person having an interest or right in or over property which is compulsorily taken possession of or whose interest in or right over any property is compulsorily acquired shall have a right of direct access to the High Court for—

(*a*) the determination of his interest or right, the legality of the taking of possession or acquisition of the property, interest or right, and the amount of any compensation to which he is entitled; and

(*b*) the purpose of obtaining prompt payment of that compensation:

Provided that if Parliament so provides in relation to a matter referred to in paragraph (*a*) the right of access shall be by way of appeal (exercisable as of right at the instance of the person having the right or interest in the property) from a tribunal or authority, other than the High Court, having jurisdiction under any law to determine that matter.

(3) The Chief Justice may make rules with respect to the practice and procedure of the High Court or any other tribunal or authority in relation to the jurisdiction conferred on the High Court by subsection (2) or exercisable by the other tribunal or authority for the purposes of that subsection (including rules with respect to the time within which applications or appeals to the High Court or applications to the other tribunal or authority may be brought).

(4) and (5) (*Deleted by 13 of 1977, s. 3.*)

(6) Nothing contained in or done under the authority of any law shall be held to be inconsistent with or in contravention of subsection (1) or (2)—

(*a*) to the extent that the law in question makes provision for the taking of possession or acquisition of property—

(i) in satisfaction of any tax, duty, rate, cess or other impost;

(ii) by way of penalty for breach of the law, whether under civil process or after conviction of a criminal offence under the law of Kenya;

(iii) as an incident of a lease, tenancy, mortgage, charge, bill of sale, pledge or contract;

(iv) in the execution of judgments or orders of a court in proceedings for the determination of civil rights or obligations;

(v) in circumstances where it is reasonably necessary so to do because the property is in a dangerous state or injurious to the health of human beings, animals or plants;

(vi) in consequence of any law with respect to the limitation of actions; or

(vii) for so long only as may be necessary for the purposes of an examination, investigation, trial or inquiry or, in the case of land, for the purposes of the carrying out thereon of work of soil conservation or the conservation of other natural resources or work relating to agricultural development or improvement (being work relating to the development or improvement that the owner or occupier of the land has been required, and has without reasonable excuse refused or failed, to carry out),

and except so far as that provision or, as the case may be, the thing done under the authority thereof is shown not to be reasonably justifiable in a democratic society; or

(*b*) to the extent that the law in question makes provision for the taking of possession or acquisition of—

(i) enemy property;

(ii) property of a deceased person, a person of unsound mind or a person who has not attained the age of eighteen years, for the purpose of its administration for the benefit of the persons entitled to the beneficial interest therein;

(iii) property of a person adjudged bankrupt or a body corporate in liquidation, for the purpose of its administration for the benefit of the creditors of the bankrupt or body corporate and, subject thereto, for the benefit of other persons entitled to the beneficial interest in the property; or

(iv) property subject to a trust, for the purpose of vesting the property in persons appointed as trustees under the instrument creating the trust or by a court or, by order of a court, for the purpose of giving effect to the trust.

(7) Nothing contained in or done under the authority of an Act of Parliament shall be held to be inconsistent with or in contravention of this section to the extent that the Act in

question makes provision for the compulsory taking possession of property or the compulsory acquisition of any interest in or right over property where that property, interest or right is vested in a body corporate, established by law for public purposes, in which no moneys have been invested other than moneys provided by Parliament.

76. (1) Except with his own consent, no person shall be subjected to the search of his person or his property or the entry by others on his premises. Protection against arbitrary search or entry.

(2) Nothing contained in or done under the authority of any law shall be held to be inconsistent with or in contravention of this section to the extent that the law in question makes provision—

(*a*) that is reasonably required in the interests of defence, public safety, public order, public morality, public health, town and country planning, the development and utilization of mineral resources, or the development or utilization of any other property in such a manner as to promote the public benefit;

(*b*) that is reasonably required for the purpose of promoting the rights or freedoms of other persons;

(*c*) that authorizes an officer or agent of the Government of Kenya, or of a local government authority, or of a body corporate established by law for public purposes, to enter on the premises of a person in order to inspect those premises or anything thereon for the purpose of a tax, rate or due or in order to carry out work connected with property that is lawfully on those premises and that belongs to that Government, authority or body corporate, as the case may be; or

(*d*) that authorizes, for the purpose of enforcing the judgment or order of a court in civil proceedings, the entry upon premises by order of a court,

and except so far as that provision or, as the case may be, anything done under the authority thereof is shown not to be reasonably justifiable in a democratic society.

77. (1) If a person is charged with a criminal offence, then, unless the charge is withdrawn, the case shall be afforded a fair hearing within a reasonable time by an independent and impartial court established by law. Provisions to secure protection of law.

The Foreign Investment Protection Act

Appendix IX

CHAPTER 518

35 of 1964, 6 of 1976.

THE FOREIGN INVESTMENTS PROTECTION ACT

Commencement: 15th December 1964

An Act of Parliament to give protection to certain approved foreign investments and for matters incidental thereto

Short title.

1. This Act may be cited as the Foreign Investments Protection Act.

Interpretation. 6 of 1976, Sch.

2. (1) In this Act, except where the context otherwise requires—

"approved" in relation to any enterprise, foreign currency, period, sum or amount means any enterprise, currency, period, sum or amount specified in the relevant certificate issued under section 3;

"foreign assets" includes foreign currency, credits, rights, benefits or property, any currency, credits, rights, benefits or property obtained by the expenditure of foreign currency, the provision of foreign credit, or the use or exploitation of foreign rights, benefits or property, and any profits from an investment in an approved enterprise by the holder of a certificate issued under section 3 in relation to that enterprise;

"foreign national" means a person who is not a citizen of Kenya, and includes a body corporate which was not incorporated in Kenya.

(2) For the avoidance of doubt it is declared that assets shall not cease to be foreign assets by reason of their being assets in some other part of the Commonwealth, and that currency shall not cease to be foreign currency by reason of it being in Kenya as well as in some place outside Kenya, so long as, in the case of currency, the relevant sum originates from outside Kenya.

Foreign investors may apply for and be granted certificates. 6 of 1976, Sch.

3. (1) A foreign national who proposes to invest foreign assets in Kenya may apply to the Minister for a certificate that the enterprise in which the assets are proposed to be invested is an approved enterprise for the purposes of this Act.

(2) The Minister shall consider every application made under subsection (1) and, in any case in which he is satisfied that the enterprise would further the economic development

of, or would be of benefit to, Kenya, he may issue a certificate to the applicant.

(3) Foreign nationals who have already invested foreign assets in Kenya shall be entitled to the grant of a certificate on application:

Provided that a certificate may be withheld if the Minister is not satisfied that the enterprise is of benefit to Kenya.

(4) Every certificate shall state—

(*a*) the name of the holder;

(*b*) the name and a description of the enterprise;

(*c*) the amount of the foreign assets invested or to be invested by the holder of the certificate in the enterprise divided as between—

(i) capital, being deemed to be a fixed amount representing the equity of the holder in the enterprise for the purposes of this Act and which shall be expressed in the certificate in, and shall for the purposes of this Act be in, Kenya currency; and

(ii) any loan, which may be expressed in, and may for the purposes of this Act be in, either Kenya currency or the relevant foreign currency;

(*d*) the relevant foreign currency;

(*e*) if the assets have not yet been invested, the value thereof and the period within which they shall be invested;

(*f*) such other matters as may be necessary or desirable for the purposes of this Act.

Amendment of certificate.

4. The Minister may amend a certificate granted under section 3—

(*a*) in any case in which he is satisfied that some other foreign national has succeeded to the interest in the enterprise of the holder of the certificate, by substituting for the name of the holder the name of his successor: 6 of 1976, sch.

Provided that the Minister shall not substitute the name of any person who has acquired the interest of the holder by the expenditure, directly or indirectly, of assets other than foreign assets;

(*b*) in any case where an interest in the enterprise passes to any other person on the death of the holder;

(*c*) in any case where the name of the enterprise is altered, by substituting the name as so altered;

(*d*) in any case in which new foreign assets are invested or are to be invested in the enterprise by the holder, or the holder has withdrawn or been paid, in accordance with this Act, any part of his investment by varying the approved amount in accordance therewith;

(*e*) in any case where the investment consists of the acquisition of shares or stock of a body corporate, and new shares or stock are acquired otherwise than by the investment of assets which are not foreign assets, by amending the number or amount and the description thereof;

(*f*) with the written consent of the holder of the certificate, by varying the approved foreign currency;

(*g*) by extending the period during which foreign assets are to be invested; and

(*h*) subject to these foregoing provisions and to the written consent of the holder, in such other manner as may be necessary or desirable.

Foreign assets to be brought in during approved period.

5. If, at the time at which a certificate is issued under this Act, any foreign assets or part thereof to which the certificate relates have not been invested in the approved enterprise, they shall be so invested within the approved period, and, if not so invested within that period, the certificate shall be deemed to have been revoked.

Compliance with Cap. 113.

6. Nothing in this Act shall affect the obligation of an investor other than an investor from one of the scheduled territories to comply initially with the requirements of the Exchange Control Act.

Transfer of profits, etc. 6 of 1976, Sch.

7. Notwithstanding the provisions of any other law for the time being in force, the holder of a certificate may, in respect of the approved enterprise to which the certificate relates, transfer out of Kenya in the approved foreign currency and at the prevailing official rate of exchange—

(*a*) the profits, after taxation, arising from or out of his investment of foreign assets:

Provided that any increase in the capital value of the investment arising out of the sale of the whole or any part of the capital assets of the enterprise shall not be deemed to be a profit arising from or out of the investment for the purposes of this Act;

(*b*) the capital specified in the certificate as representing and being deemed to be the fixed amount of the equity of the holder of the certificate in the enterprise for the purpose of this Act:

Provided that—

(i) where any amendment or variation is made in the amount of the capital under the provisions of section 4, the amended or varied amount shall be substituted for the original amount; and

(ii) no additional amount or sum shall be added to the capital specified in the certificate (as amended or varied) to represent any increase in the capital value of the investment since the issue of the certificate or since the last amendment or variation of the certificate; and

(*c*) the principal and interest of any loan specified in the certificate.

Compulsory acquisition.

8. No approved enterprise or any property belonging thereto shall be compulsorily taken possession of, and no interest in or right over such enterprise or property shall be compulsorily acquired, except in accordance with the provisions concerning compulsory taking of possession and acquisition and the payment of full and prompt payment of compensation contained in section 75 of the Constitution and reproduced in the Schedule to this Act.

Regulations and directions.

9. The Minister may make regulations or give directions generally for the better carrying out of the purposes of this Act and prescribing the manner in which applications shall be made for certificates under this Act, and the information which shall accompany those applications.

THE FOREIGN INVESTMENTS PROTECTION (AMENDMENT) ACT, 1988

No. 7 of 1988

Date of Assent: 11th August, 1988

Date of Commencement: 19th August, 1988

An Act of Parliament to amend the Foreign Investments Protection Act

ENACTED by the Parliament of Kenya as follows:—

Short title.

1. This Act may be cited as the Foreign Investments Protection (Amendment) Act, 1988.

Application.

2. The provisions of this Act shall apply to investments in respect of which a certificate of approved enterprise is granted or amended by the Minister after the commencement of this Act.

Amendment of section 3 of Cap. 518.

3. Section 3 of the Foreign Investments Protection Act, in this Act referred to as the principal Act, is amended—

(*a*) by repealing subsection (3);

(*b*) in subsection (4)—

(i) by deleting paragraphs (*c*) and (*d*) and inserting the following new paragraphs—

(*c*) the amount of the foreign assets invested or to be invested by the holder of the certificate in the enterprise divided as between—

(i) capital, being deemed to be a fixed amount representing the equity of the holder in the enterprise for the purposes of this Act and which shall be expressed in the certificate in, and shall for the purposes of this Act be in, either Kenya currency or the relevant foreign currency; and

(ii) any loan, which may be expressed in, and may for the purposes of this Act be in, either Kenya currency or the relevant foreign currency;

(*d*) the foreign currency invested or to be invested;

(ii) by deleting paragraph (*e*);

(*c*) by inserting the following new subsection—

(5) If the foreign assets have not yet been invested a conditional certificate shall be issued stating, in addition to the details specified in subsection (3), the period in which they shall be invested.

Amendment of section 4 of Cap. 518.

4. Section 4 of the principal Act is amended by deleting paragraph (*d*) and inserting the following new paragraph—

(*d*) in any case in which new foreign assets are invested or are to be invested in the enterprise by the holder, or the holder has withdrawn or been paid, in accordance with this Act, any part of his investment by varying the approved amount in either Kenya currency or the relevant foreign currency in accordance therewith.

Amendment of section 7 of Cap. 518.

5. Section 7 of the principal Act is amended by deleting paragraph (*a*) and inserting the following new paragraph—

(*a*) the profits, including retained profits which have not been capitalized, after taxation, arising from or out of his investment in foreign assets:

Provided that any increase in the capital value of the investment arising out of the sale of the whole or any part of the capital assets of the enterprise or revaluation of capital assets shall not be deemed to be profit arising from or out of the investment for the purposes of this Act.

Insertion of new section 8A in Cap. 518.

6. The principal Act is amended by inserting the following new section immediately after section 8—

Investment of proceeds.

8A. Any proceeds realized from the sale of foreign assets which may not be transferred out of Kenya in the manner provided for under section 7 shall be invested in Government securities for a period of five years:

Provided that—

(i) the income from the Government securities in which the proceeds are invested may be transferred out of Kenya under the same terms as interest under paragraph (c) of section 7; and

(ii) the capital may be transferred out of Kenya at the end of five years on the same terms as other funds in the manner provided for under section 7.

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SOURCE OF FUNDS:												
-Net Income	0	0	0	0	5,609	6,243	6,948	7,735	8,609	5,510	6,134	6,828
-Depreciation	0	0	0	0	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
-Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Equity Contribution	0	0	0	0	25,380	0	0	0	0	0	0	0
-Reduction In Debt	0	0	0	0	0	0	0	0	0	0	0	0
-Debt	0	0	0	0	101,520	0	0	0	0	0	0	0
Total Source Of Funds	0	0	0	0	137,585	11,319	12,024	12,811	13,685	10,586	11,210	11,904
USE OF FUNDS:												
-Capital Expenditures	0	0	0	0	126,900	0	0	0	0	0	0	0
-Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Spare Parts	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital Escalation	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Reserve Deposits	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Retirement (Fixed)	0	0	0	0	6,268	6,931	7,666	8,481	9,385	10,390	11,505	3,845
Total Use Of Funds	0	0	0	0	133,168	6,931	7,666	8,481	9,385	10,390	11,505	3,845

PROJECT After Tax Cash Flows (Source Less Use Of Funds):	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Equity Contributions	0	0	0	0	(25,380)	0	0	0	0	0	0	0
-Annual Cash Flows	0	0	0	0	4,417	4,388	4,358	4,330	4,300	196	(295)	8,059
-Cumulative Cash Flows	0	0	0	0	4,417	8,804	13,162	17,492	21,792	21,988	21,693	29,752
-Total Annual Cash Flows	0	0	0	0	(20,963)	4,388	4,358	4,330	4,300	196	(295)	8,059
-Total Cumulative Cash Flows	0	0	0	0	(20,963)	(16,576)	(12,218)	(7,888)	(3,588)	(3,392)	(3,687)	4,372

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
6,988	7,161	7,349	7,553	7,776	8,017	8,279	8,563	8,544	8,525	8,505	8,485	8,465	8,445	8,425	8,404	8,384
5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12,064	12,237	12,425	12,629	12,852	13,093	13,355	13,639	13,620	13,601	13,581	13,561	13,541	13,521	13,501	13,480	13,460
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4,152	4,484	4,843	5,231	5,649	6,101	6,589	0	0	0	0	0	0	0	0	0	0
4,152	4,484	4,843	5,231	5,649	6,101	6,589	0	0	0	0	0	0	0	0	0	0

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7,912	7,753	7,582	7,398	7,203	6,992	6,766	13,639	13,620	13,601	13,581	13,561	13,541	13,521	13,501	13,480	13,460
37,664	45,417	52,999	60,397	67,600	74,593	81,359	94,998	108,618	122,218	135,799	149,360	162,902	176,423	189,924	203,404	216,864
7,912	7,753	7,582	7,398	7,203	6,992	6,766	13,639	13,620	13,601	13,581	13,561	13,541	13,521	13,501	13,480	13,460
12,284	20,037	27,619	35,017	42,220	49,213	55,979	69,618	83,238	96,838	110,419	123,980	137,522	151,043	164,544	178,024	191,484

KENYA GEOTHERMAL PROJECT
BALANCE STATEMENT

	1995	1996	1997	1998	1999	2000	2001	2002
ASSETS:								
Construction WIP	0	0	0	0	0	0	0	0
Property, Plant & Equipment								
-Beginning Balance	126,900	121,824	116,748	111,672	106,596	101,520	96,444	91,368
-Accumulated Depreciation	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
Ending Balance	121,824	116,748	111,672	106,596	101,520	96,444	91,368	86,292
Working Capital	0	0	0	0	0	0	0	0
Debt Reserve	0	0	0	0	0	0	0	0
TOTAL ASSETS	121,824	116,748	111,672	106,596	101,520	96,444	91,368	86,292
LIABILITIES & EQUITY:								
-Long Term Debt	95,252	(6,931)	(7,666)	(8,481)	(9,385)	(10,390)	(11,505)	(3,845)
-Deferred Taxes	0	0	0	0	0	0	0	0
-Equity & Accumulated Earnings	26,572	123,679	119,338	115,077	110,905	106,834	102,873	90,137
TOTAL LIABILITIES & EQUITY	121,824	116,748	111,672	106,596	101,520	96,444	91,368	86,292

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86,292	81,216	76,140	71,064	65,988	60,912	55,836	50,760	45,684	40,608	35,532	30,456	25,380	20,304	15,228	10,152	5,076
5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
81,216	76,140	71,064	65,988	60,912	55,836	50,760	45,684	40,608	35,532	30,456	25,380	20,304	15,228	10,152	5,076	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81,216	76,140	71,064	65,988	60,912	55,836	50,760	45,684	40,608	35,532	30,456	25,380	20,304	15,228	10,152	5,076	0
(4,152)	(4,484)	(4,843)	(5,231)	(5,649)	(6,101)	(6,589)	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85,368	80,624	75,907	71,219	66,561	61,937	57,349	45,684	40,608	35,532	30,456	25,380	20,304	15,228	10,152	5,076	0
81,216	76,140	71,064	65,988	60,912	55,836	50,760	45,684	40,608	35,532	30,456	25,380	20,304	15,228	10,152	5,076	0

KENYA GEOTHERMAL PROJECT
INTEREST EXPENSE AND DEBT RETIEMENT

Fixed Loan #1 (Commercial Bank)

Annual Payment:	$8,898 (If Levelized)
Grace Period	0 years
Loan Principle:	40,608
Interest Rate:	12.00%
Term:	7 years

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
			--------	-------	-------	-------	-------
	Status	Orig. Bal.		40,608			40,608
1	payment	1995	8,898	40,608	4,025	4,873	36,583
2	payment	1996	8,898	36,583	4,508	4,390	32,075
3	payment	1997	8,898	32,075	5,049	3,849	27,026
4	payment	1998	8,898	27,026	5,655	3,243	21,371
5	payment	1999	8,898	21,371	6,333	2,565	15,038
6	payment	2000	8,898	15,038	7,093	1,805	7,945
7	payment	2001	8,898	7,945	7,945	953	0
8	paid	2002	0	0	0	0	0
9	paid	2003	0	0	0	0	0
10	paid	2004	0	0	0	0	0
11	paid	2005	0	0	0	0	0
12	paid	2006	0	0	0	0	0
13	paid	2007	0	0	0	0	0
14	paid	2008	0	0	0	0	0
15	paid	2009	0	0	0	0	0
16	paid	2010	0	0	0	0	0
17	paid	2011	0	0	0	0	0
18	paid	2012	0	0	0	0	0
19	paid	2013	0	0	0	0	0
20	paid	2014	0	0	0	0	0
21	paid	2015	0	0	0	0	0
22	paid	2016	0	0	0	0	0
23	paid	2017	0	0	0	0	0
24	paid	2018	0	0	0	0	0
25	paid	2019	0	0	0	0	0
			--------		-------	-------	
Total:			62,286		40,608	21,678	
			========		=======	=======	

Fixed Loan #2 (Supplier)

Annual Payment:	$7,116 (If Levelized)
Grace Period	0
Loan Principle:	60,912
Interest Rate:	8.00%
Term:	15 yrs

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
			--------	-------	-------	-------	-------
	Status	Orig. Bal.		60,912			60,912
1	payment	1995	7,116	60,912	2,243	4,873	58,669
2	payment	1996	7,116	58,669	2,423	4,693	56,246
3	payment	1997	7,116	56,246	2,617	4,500	53,629
4	payment	1998	7,116	53,629	2,826	4,290	50,803
5	payment	1999	7,116	50,803	3,052	4,064	47,751
6	payment	2000	7,116	47,751	3,296	3,820	44,455
7	payment	2001	7,116	44,455	3,560	3,556	40,895
8	payment	2002	7,116	40,895	3,845	3,272	37,050
9	payment	2003	7,116	37,050	4,152	2,964	32,898
10	payment	2004	7,116	32,898	4,484	2,632	28,413
11	payment	2005	7,116	28,413	4,843	2,273	23,570
12	payment	2006	7,116	23,570	5,231	1,886	18,339
13	payment	2007	7,116	18,339	5,649	1,467	12,690
14	payment	2008	7,116	12,690	6,101	1,015	6,589
15	payment	2009	7,116	6,589	6,589	527	(0)
16	paid	2010	0	0	(0)	0	0
17	paid	2011	0	0	(0)	0	0
18	paid	2012	0	0	(0)	0	0
19	paid	2013	0	0	(0)	0	0
20	paid	2014	0	0	(0)	0	0
21	paid	2015	0	0	(0)	0	0
22	paid	2016	0	0	(0)	0	0
23	paid	2017	0	0	(0)	0	0
24	paid	2018	0	0	(0)	0	0
25	paid	2019	0	0	(0)	0	0
			--------		-------	-------	
Total:			106,745		60,912	45,833	
			========		=======	=======	

Kenyan Inflation:	8.0%		
Partnership Share:	100.0%		Project: Eburru
Debt Finance % :	80.0%		Base Cost: US$3,034/kW
U.S. Fed Tax Rate:	39.0%		15-Year BOT
Kenyan Tax Rate:	42.5%		
Exchange Rate (1991):	23.00	KSh/$	
Devaluation Rate:	8.0%	per year	
Tax Holiday Status	yes		

Fixed Loan Rates/Terms:	Rate	Years	Grace Period	% Financed
Commercial Banks:	12.00%	7	0	40.00%
Suppliers:	10.00%	15	0	60.00%
Donors:	0.00%	0	0	0.00%

Project Assumptions:

O&M Esc Rate:	1.0%		
O&M Base Cost (mills/kWh)	12.7		
Tax Esc Rate:	N/A		
Avoided Cost (cents/kWh)	7.10	IRR ==>	20.05%
Project Size (MW's):	20		
Capacity Factor:	95.00%		
Project Life:	25 years		
Capital Cost per kW	3.034 (000's)	Adder:	0.00%
Time to Build	3 years		
Construction Date:	1991		
On-Line Date:	1994		
Project Costs:	60,680 (000's)		

KENYA GEOTHERMAL PROJECT
SUMMARY SHEET

PROJECT IRR: 15 years	20%
PROJECT NPV @ 10 %	15.5 Million
PROJECT NPV @ 12 %	10.8 Million
PROJECT NPV @ 14 %	7.4 Million
TOTAL PROJECT COSTS: $	60.68 Million

PROJECT COST	$60.68 Million	100%	Debt
PARTNERSHIP EQUITY	$12.14 Million	20%	Equity
TERM LOAN	$48.54 Million	80%	

KENYA GEOTHERMAL PROJECT
CAPITAL COST BUDGET

FACILITY COSTS:	
-Turnkey Construction	0
-Performance Bond	0
-Engineering	0
-Unidentified Scope Changes	0
-Identified Scope Changes	0
-Electrical Interconnect	0
-Contingency	0

Total Facility Costs	0
DEVELOPMENT COSTS:	
-Project Management	0
-Miscellaneous Development Costs	0
-Startup	0
-Builder's Insurance	0
-Legal	0
-Development Fee	0

Total Development Costs	0
FINANCING COSTS:	
-Engineers	0
-Bank Expenses	0
-Lendor Underwriting Fee	0
-Commitment Fee	0
-Agency Fee	0
-Consultants	0
-Title Insurance	0
-Lendor's Counsel	0

Total Financing Costs	0
Hard, Soft, & Finance Costs	60,680
Construction Interest	0
Total Expenditures	60,680
NON-DEPRECIABLE PROPERTY:	
-Working Capital	0
-Spare Parts	0
-Land	0
-Repair & Replacement Reserve	0

Total Non-Depreciable Prop	0
DEBT RESERVE	0

TOTAL PROJECT COSTS	60,680

ELECTRICITY REVENUES

		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Output (MW)		0	0	0	20	20	20	20	20	20	20	20	20
Average Availability (%)		0	0	0	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
Hours On Line		0	0	0	8322	8322	8322	8322	8322	8322	8322	8322	8322
kWh Sold (000's)		0	0	0	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440
Estimated Annual Avoided Costs (cents/kWh)		0	0	0	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10
Exchange Rate (KSh/$)		23.00	24.84	26.83	28.97	31.29	33.79	36.50	39.42	42.57	45.98	49.66	53.63
Escalation Rate Above Inflation	0.00%	0	0	0	0	0	0	0	0	0	0	0	0
Total Electric Revenues ($000)		0	0	0	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817

Operating Revenues:		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Electricity:		0	0	0	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817
-Inv Income (Debt Reserve @ 6%)		0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues: ($000)		0	0	0	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817
Operating Costs:													
-Fuel Oil (Standby)		0	0	0	0	0	0	0	0	0	0	0	0
-O&M Escalated at:	1.00%	0	0	0	2,114	2,135	2,156	2,178	2,200	2,222	2,244	2,266	2,289
-Turbine Overhaul		0	0	0	0	0	0	0	0	0	0	0	0
-Administration		0	0	0	0	0	0	0	0	0	0	0	0
-Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0
-Insurance		0	0	0	0	0	0	0	0	0	0	0	0
-Franchise Tax		0	0	0	0	0	0	0	0	0	0	0	0
-Gross Receipts Tax		0	0	0	0	0	0	0	0	0	0	0	0
-Depreciation		0	0	0	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
Total Operating Costs ($ 000)		0	0	0	4,541	4,562	4,583	4,605	4,627	4,649	4,671	4,693	4,716
Operating Margin		0	0	0	7,276	7,255	7,234	7,212	7,190	7,168	7,146	7,124	7,101
Interest Expense		0	0	0	4,660	4,343	3,992	3,602	3,170	2,690	2,156	1,564	1,417
Income Before Taxes & After Interest		0	0	0	2,616	2,912	3,242	3,610	4,020	4,478	4,990	5,560	5,684
Provision For Taxes:													
-Current at Assumed Rate	42.50%	0	0	0	0	0	0	0	0	1,903	2,121	2,363	2,416
-Deferred		0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes		0	0	0	0	0	0	0	0	1,903	2,121	2,363	2,416
NET INCOME (After Taxes & Interest)		0	0	0	2,616	2,912	3,242	3,610	4,020	2,575	2,869	3,197	3,268

	1994	1995	1996	1997	1998	1999	2000	2001	2002
Income Before Taxes and Aft Interest	2,616	2,912	3,242	3,610	4,020	4,478	4,990	5,560	5,684
Plus: Book Depreciation	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
Less: Principal Retirement	(2,997)	(3,314)	(3,665)	(4,055)	(4,488)	(4,968)	(5,501)	(1,838)	(1,986)
Less: Working Capital Escalation	0	0	0	0	0	0	0	0	0
Cash Flow Before Taxes (CFBT)	2,046	2,025	2,004	1,982	1,960	1,938	1,916	6,149	6,125

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322
166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440
7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10	7.10
57.92	62.55	67.56	72.96	78.80	85.10	91.91	99.26	107.20	115.78	125.04	135.04	145.85	157.51	170.12	183.73
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817	11,817
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,312	2,335	2,358	2,382	2,406	2,430	2,454	2,479	2,503	2,528	2,554	2,579	2,605	2,631	2,657	2,684
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
4,739	4,762	4,785	4,809	4,833	4,857	4,881	4,906	4,931	4,956	4,981	5,006	5,032	5,058	5,085	5,111
7,078	7,055	7,032	7,008	6,984	6,960	6,936	6,911	6,887	6,862	6,836	6,811	6,785	6,759	6,733	6,706
1,258	1,087	902	702	485	252	0	0	0	0	0	0	0	0	0	0
5,820	5,968	6,130	6,306	6,499	6,708	6,936	6,911	6,887	6,862	6,836	6,811	6,785	6,759	6,733	6,706
2,474	2,536	2,605	2,680	2,762	2,851	2,948	2,937	2,927	2,916	2,905	2,895	2,884	2,873	2,861	2,850
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,474	2,536	2,605	2,680	2,762	2,851	2,948	2,937	2,927	2,916	2,905	2,895	2,884	2,873	2,861	2,850
3,347	3,432	3,525	3,626	3,737	3,857	3,988	3,974	3,960	3,945	3,931	3,916	3,901	3,886	3,871	3,856
5,820	5,968	6,130	6,306	6,499	6,708	6,936	6,911	6,887	6,862	6,836	6,811	6,785	6,759	6,733	6,706
2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
(2,144)	(2,316)	(2,501)	(2,701)	(2,917)	(3,151)	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,103	6,079	6,056	6,032	6,010	5,984	9,363	9,339	9,314	9,289	9,264	9,238	9,212	9,186	9,160	9,133

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SOURCE OF FUNDS:												
-Net Income	0	0	0	2,616	2,912	3,242	3,610	4,020	2,575	2,869	3,197	3,268
-Depreciation	0	0	0	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
-Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Equity Contribution	0	0	0	12,136	0	0	0	0	0	0	0	0
-Reduction In Debt	0	0	0	0	0	0	0	0	0	0	0	0
-Debt	0	0	0	48,544	0	0	0	0	0	0	0	0
Total Source Of Funds	0	0	0	65,723	5,339	5,669	6,037	6,448	5,002	5,297	5,624	5,696
USE OF FUNDS:												
-Capital Expenditures	0	0	0	60,680	0	0	0	0	0	0	0	0
-Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Spare Parts	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital Escalation	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Reserve Deposits	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Retirement (Fixed)	0	0	0	2,997	3,314	3,665	4,055	4,488	4,968	5,501	1,838	1,986
Total Use Of Funds	0	0	0	63,677	3,314	3,665	4,055	4,488	4,968	5,501	1,838	1,986
PROJECT After Tax Cash Flows (Source Less Use Of Funds):	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Equity Contributions	0	0	0	(12,136)	0	0	0	0	0	0	0	0
-Annual Cash Flows	0	0	0	2,046	2,025	2,004	1,982	1,960	34	(204)	3,786	3,710
-Cumulative Cash Flows	0	0	0	2,046	4,072	6,076	8,058	10,018	10,052	9,848	13,634	17,343
-Total Annual Cash Flows	0	0	0	(10,090)	2,025	2,004	1,982	1,960	34	(204)	3,786	3,710
-Total Cumulative Cash Flows	0	0	0	(10,090)	(8,064)	(6,060)	(4,078)	(2,118)	(2,084)	(2,288)	1,498	5,207

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
3,347	3,432	3,525	3,626	3,737	3,857	3,988	3,974	3,960	3,945	3,931	3,916	3,901	3,886	3,871	3,856
2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5,774	5,859	5,952	6,053	6,164	6,284	6,415	6,401	6,387	6,373	6,358	6,343	6,329	6,314	6,298	6,283
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,144	2,316	2,501	2,701	2,917	3,151	0	0	0	0	0	0	0	0	0	0
2,144	2,316	2,501	2,701	2,917	3,151	0	0	0	0	0	0	0	0	0	0
2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3,630	3,543	3,451	3,352	3,247	3,133	6,415	6,401	6,387	6,373	6,358	6,343	6,329	6,314	6,298	6,283
20,973	24,516	27,967	31,319	34,566	37,700	44,115	50,516	56,904	63,276	69,634	75,978	82,306	88,620	94,918	101,202
3,630	3,543	3,451	3,352	3,247	3,133	6,415	6,401	6,387	6,373	6,358	6,343	6,329	6,314	6,298	6,283
8,837	12,380	15,831	19,183	22,430	25,564	31,979	38,380	44,768	51,140	57,498	63,842	70,170	76,484	82,782	89,066

KENYA GEOTHERMAL PROJECT
BALANCE STATEMENT

	1994	1995	1996	1997	1998	1999	2000	2001	2002
ASSETS:									
Construction WIP	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment									
-Beginning Balance	60,680	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262
-Accumulated Depreciation	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
Ending Balance	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835
Working Capital	0	0	0	0	0	0	0	0	0
Debt Reserve	0	0	0	0	0	0	0	0	0
TOTAL ASSETS	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835
LIABILITIES & EQUITY:									
-Long Term Debt	45,547	(3,314)	(3,665)	(4,055)	(4,488)	(4,968)	(5,501)	(1,838)	(1,986)
-Deferred Taxes	0	0	0	0	0	0	0	0	0
-Equity & Accumulated Earnings	12,706	59,140	57,063	55,026	53,032	51,085	49,191	43,100	40,821
TOTAL LIABILITIES & EQUITY	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38,835	36,408	33,981	31,554	29,126	26,699	24,272	21,845	19,418	16,990	14,563	12,136	9,709	7,282	4,854	2,427
2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
36,408	33,981	31,554	29,126	26,699	24,272	21,845	19,418	16,990	14,563	12,136	9,709	7,282	4,854	2,427	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36,408	33,981	31,554	29,126	26,699	24,272	21,845	19,418	16,990	14,563	12,136	9,709	7,282	4,854	2,427	0
(2,144)	(2,316)	(2,501)	(2,701)	(2,917)	(3,151)	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38,552	36,297	34,055	31,827	29,616	27,423	21,845	19,418	16,990	14,563	12,136	9,709	7,282	4,854	2,427	0
36,408	33,981	31,554	29,126	26,699	24,272	21,845	19,418	16,990	14,563	12,136	9,709	7,282	4,854	2,427	0

KENYA GEOTHERMAL PROJECT
INTEREST EXPENSE AND DEBT RETIEMENT

Fixed Loan #1 (Commercial Bank)

Annual Payment:	$4,255 (If Levelized)
Grace Period	0 years
Loan Principle:	19,418
Interest Rate:	12.00%
Term:	7 years

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
			--------	-------	-------	-------	-------
		Orig. Bal.		19,418			19,418
1	payment	1994	4,255	19,418	1,925	2,330	17,493
2	payment	1995	4,255	17,493	2,156	2,099	15,337
3	payment	1996	4,255	15,337	2,414	1,840	12,923
4	payment	1997	4,255	12,923	2,704	1,551	10,219
5	payment	1998	4,255	10,219	3,028	1,226	7,191
6	payment	1999	4,255	7,191	3,392	863	3,799
7	payment	2000	4,255	3,799	3,799	456	(0)
8	paid	2001	0	0	(0)	0	0
9	paid	2002	0	0	(0)	0	0
10	paid	2003	0	0	(0)	0	0
11	paid	2004	0	0	(0)	0	0
12	paid	2005	0	0	(0)	0	0
13	paid	2006	0	0	(0)	0	0
14	paid	2007	0	0	(0)	0	0
15	paid	2008	0	0	(0)	0	0
16	paid	2009	0	0	(0)	0	0
17	paid	2010	0	0	(0)	0	0
18	paid	2011	0	0	(0)	0	0
19	paid	2012	0	0	(0)	0	0
20	paid	2013	0	0	(0)	0	0
21	paid	2014	0	0	(0)	0	0
22	paid	2015	0	0	(0)	0	0
23	paid	2016	0	0	(0)	0	0
24	paid	2017	0	0	(0)	0	0
25	paid	2018	0	0	(0)	0	0
			--------		-------	-------	
Total:			29,783		19,418	10,366	
			========		=======	=======	

Fixed Loan #2 (Supplier)

Annual Payment:	$3,829 (If Levelized)
Grace Period	0
Loan Principle:	29,126
Interest Rate:	10.00%
Term:	15 yrs

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
			--------	-------	-------	-------	-------
		Orig. Bal.		29,126			29,126
1	payment	1994	3,829	29,126	917	2,913	28,210
2	payment	1995	3,829	28,210	1,008	2,821	27,201
3	payment	1996	3,829	27,201	1,109	2,720	26,092
4	payment	1997	3,829	26,092	1,220	2,609	24,872
5	payment	1998	3,829	24,872	1,342	2,487	23,530
6	payment	1999	3,829	23,530	1,476	2,353	22,053
7	payment	2000	3,829	22,053	1,624	2,205	20,429
8	payment	2001	3,829	20,429	1,786	2,043	18,643
9	payment	2002	3,829	18,643	1,965	1,864	16,678
10	payment	2003	3,829	16,678	2,162	1,668	14,516
11	payment	2004	3,829	14,516	2,378	1,452	12,139
12	payment	2005	3,829	12,139	2,616	1,214	9,523
13	payment	2006	3,829	9,523	2,877	952	6,646
14	payment	2007	3,829	6,646	3,165	665	3,481
15	payment	2008	3,829	3,481	3,481	348	0
16	paid	2009	0	0	(0)	0	0
17	paid	2010	0	0	(0)	0	0
18	paid	2011	0	0	(0)	0	0
19	paid	2012	0	0	(0)	0	0
20	paid	2013	0	0	(0)	0	0
21	paid	2014	0	0	(0)	0	0
22	paid	2015	0	0	(0)	0	0
23	paid	2016	0	0	(0)	0	0
24	paid	2017	0	0	(0)	0	0
25	paid	2018	0	0	(0)	0	0
			--------		-------	-------	
Total:			57,440		29,126	28,314	
			========		=======	=======	

Kenyan Inflation:	8.0%			
Partnership Share:	100.0%		Project:	Arus
Debt Finance % :	80.0%		Base Cost:	US$3,324/kW
U.S. Fed Tax Rate:	39.0%		15-Year BOT	
Kenyan Tax Rate:	42.5%			
Exchange Rate (1991):	23.00	KSh/$		
Devaluation Rate:	8.0%	per year		
Tax Holiday Status	yes			

Fixed Loan Rates/Terms:	Rate	Years	Grace Period	% Financed
Commercial Banks:	12.00%	7	0	40.00%
Suppliers:	8.00%	15	0	60.00%
Donors:	0.00%	0	0	0.00%

Project Assumptions:

O&M Esc Rate:	1.0%			
O&M Base Cost (mills/kWh)	13.1			
Tax Esc Rate:	N/A			
Avoided Cost (cents/kWh)	7.72		IRR ==>	19.55%
Project Size (MW's):	20			
Capacity Factor:	95.00%			
Project Life:	25	years		
Capital Cost per kW	3.324	(000's)	Adder:	0.00%
Time to Build	4	years		
Construction Date:	1991			
On-Line Date:	1995			
Project Costs:	66,480	(000's)		

KENYA GEOTHERMAL PROJECT
SUMMARY SHEET

PROJECT IRR: 15 years	20%
PROJECT NPV @ 10 %	17.3 Million
PROJECT NPV @ 12 %	12.2 Million
PROJECT NPV @ 14 %	8.4 Million
TOTAL PROJECT COSTS: $	66.48 Million

PROJECT COST	$66.48 Million	100%	Debt
PARTNERSHIP EQUITY	$13.30 Million	20%	Equity
TERM LOAN	$53.18 Million	80%	

KENYA GEOTHERMAL PROJECT
CAPITAL COST BUDGET

FACILITY COSTS:	
-Turnkey Construction	0
-Performance Bond	0
-Engineering	0
-Unidentified Scope Changes	0
-Identified Scope Changes	0
-Electrical Interconnect	0
-Contingency	0

Total Facility Costs	0
DEVELOPMENT COSTS:	
-Project Management	0
-Miscellaneous Development Costs	0
Startup	0
-Builder's Insurance	0
-Legal	0
-Development Fee	0

Total Development Costs	0
FINANCING COSTS:	
-Engineers	0
-Bank Expenses	0
-Lendor Underwriting Fee	0
-Commitment Fee	0
-Agency Fee	0
-Consultants	0
-Title Insurance	0
-Lendor's Counsel	0

Total Financing Costs	0
Hard, Soft, & Finance Costs	66,480
Construction Interest	0
Total Expenditures	66,480
NON-DEPRECIABLE PROPERTY:	
-Working Capital	0
-Spare Parts	0
-Land	0
-Repair & Replacement Reserve	0

Total Non-Depreciable Prop	0
DEBT RESERVE	0

TOTAL PROJECT COSTS	66,480
	========

KENYA GEOTHERMAL PROJECT
ELECTRICITY REVENUES

		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Output (MW)		0	0	0	0	20	20	20	20	20	20	20	20
Average Availability (%)		0	0	0	0	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
Hours On Line		0	0	0	0	8322	8322	8322	8322	8322	8322	8322	8322
kWh Sold (000's)		0	0	0	0	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440
Estimated Annual Avoided Costs (cents/kWh)		0	0	0	0	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72
Exchange Rate (KSh/$)		23.00	24.84	26.83	28.97	31.29	33.79	36.50	39.42	42.57	45.98	49.66	53.63
Escalation Rate Above Inflation	0.00%	0	0	0	0	0	0	0	0	0	0	0	0
Total Electric Revenues ($000)		0	0	0	0	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849

Operating Revenues:		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Electricity:		0	0	0	0	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849
-Inv Income (Debt Reserve @ 6%)		0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues: ($000)		0	0	0	0	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849
Operating Costs:													
-Fuel Oil (Standby)		0	0	0	0	0	0	0	0	0	0	0	0
-O&M Escalated at:	1.00%	0	0	0	0	2,180	2,202	2,224	2,246	2,269	2,292	2,315	2,338
-Turbine Overhaul		0	0	0	0	0	0	0	0	0	0	0	0
-Administration		0	0	0	0	0	0	0	0	0	0	0	0
-Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0
-Insurance		0	0	0	0	0	0	0	0	0	0	0	0
-Franchise Tax		0	0	0	0	0	0	0	0	0	0	0	0
-Gross Receipts Tax		0	0	0	0	0	0	0	0	0	0	0	0
-Depreciation		0	0	0	0	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
Total Operating Costs ($ 000)		0	0	0	0	4,840	4,861	4,883	4,906	4,928	4,951	4,974	4,997
Operating Margin		0	0	0	0	8,010	7,988	7,966	7,944	7,921	7,898	7,875	7,852
Interest Expense		0	0	0	0	5,106	4,759	4,374	3,947	3,473	2,947	2,363	1,714
Income Before Taxes & After Interest		0	0	0	0	2,904	3,229	3,592	3,997	4,448	4,951	5,512	6,138
Provision For Taxes:													
-Current at Assumed Rate	42.50%	0	0	0	0	0	0	0	0	0	2,104	2,343	2,609
-Deferred		0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes		0	0	0	0	0	0	0	0	0	2,104	2,343	2,609
NET INCOME (After Taxes & Interest)		0	0	0	0	2,904	3,229	3,592	3,997	4,448	2,847	3,170	3,530

	1995	1996	1997	1998	1999	2000	2001	2002
Income Before Taxes and After Interest	2,904	3,229	3,592	3,997	4,448	4,951	5,512	6,138
Plus: Book Depreciation	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
Less: Principal Retirement	(3,284)	(3,631)	(4,016)	(4,443)	(4,917)	(5,443)	(6,027)	(2,014)
Less: Working Capital Escalation	0	0	0	0	0	0	0	0
Cash Flow Before Taxes (CFBT)	2,279	2,257	2,235	2,213	2,190	2,168	2,145	6,784

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322
166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440	166,440
7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72
57.92	62.55	67.56	72.96	78.80	85.10	91.91	99.26	107.20	115.78	125.04	135.04	145.85	157.51	170.12	183.73	198.42
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849	12,849
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,361	2,385	2,408	2,433	2,457	2,481	2,506	2,531	2,557	2,582	2,608	2,634	2,660	2,687	2,714	2,741	2,768
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
5,020	5,044	5,068	5,092	5,116	5,141	5,165	5,191	5,216	5,241	5,267	5,293	5,320	5,346	5,373	5,400	5,428
7,829	7,805	7,781	7,757	7,733	7,709	7,684	7,659	7,633	7,608	7,582	7,556	7,530	7,503	7,476	7,449	7,421
1,553	1,379	1,191	988	769	532	276	0	0	0	0	0	0	0	0	0	0
6,276	6,426	6,590	6,769	6,964	7,177	7,408	7,659	7,633	7,608	7,582	7,556	7,530	7,503	7,476	7,449	7,421
2,667	2,731	2,801	2,877	2,960	3,050	3,148	3,255	3,244	3,233	3,222	3,211	3,200	3,189	3,177	3,166	3,154
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,667	2,731	2,801	2,877	2,960	3,050	3,148	3,255	3,244	3,233	3,222	3,211	3,200	3,189	3,177	3,166	3,154
3,609	3,695	3,790	3,892	4,004	4,126	4,259	4,404	4,389	4,374	4,360	4,345	4,329	4,314	4,299	4,283	4,267

6,276	6,426	6,590	6,769	6,964	7,177	7,408	7,659	7,633	7,608	7,582	7,556	7,530	7,503	7,476	7,449	7,421
2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
(2,175)	(2,349)	(2,537)	(2,740)	(2,959)	(3,196)	(3,452)	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,760	6,737	6,713	6,689	6,664	6,640	6,615	10,318	10,293	10,267	10,241	10,215	10,189	10,162	10,135	10,108	10,081

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SOURCE OF FUNDS:												
-Net Income	0	0	0	0	2,904	3,229	3,592	3,997	4,448	2,847	3,170	3,530
-Depreciation	0	0	0	0	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
-Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Recovery Of Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Equity Contribution	0	0	0	0	13,296	0	0	0	0	0	0	0
-Reduction In Debt	0	0	0	0	0	0	0	0	0	0	0	0
-Debt	0	0	0	0	53,184	0	0	0	0	0	0	0
Total Source Of Funds	0	0	0	0	72,043	5,888	6,251	6,656	7,107	5,506	5,829	6,189
USE OF FUNDS:												
-Capital Expenditures	0	0	0	0	66,480	0	0	0	0	0	0	0
-Debt Reserve	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital	0	0	0	0	0	0	0	0	0	0	0	0
-Spare Parts	0	0	0	0	0	0	0	0	0	0	0	0
-Working Capital Escalation	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Reserve Deposits	0	0	0	0	0	0	0	0	0	0	0	0
-Debt Retirement (Fixed)	0	0	0	0	3,284	3,631	4,016	4,443	4,917	5,443	6,027	2,014
Total Use Of Funds	0	0	0	0	69,764	3,631	4,016	4,443	4,917	5,443	6,027	2,014
PROJECT After Tax Cash Flows (Source Less Use Of Funds):	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
-Equity Contributions	0	0	0	0	(13,296)	0	0	0	0	0	0	0
-Annual Cash Flows	0	0	0	0	2,279	2,257	2,235	2,213	2,190	63	(198)	4,175
-Cumulative Cash Flows	0	0	0	0	2,279	4,536	6,771	8,984	11,174	11,237	11,039	15,214
-Total Annual Cash Flows	0	0	0	0	(11,017)	2,257	2,235	2,213	2,190	63	(198)	4,175
-Total Cumulative Cash Flows	0	0	0	0	(11,017)	(8,760)	(6,525)	(4,312)	(2,122)	(2,059)	(2,257)	1,918

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
3,609	3,695	3,790	3,892	4,004	4,126	4,259	4,404	4,389	4,374	4,360	4,345	4,329	4,314	4,299	4,283	4,267
2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,268	6,354	6,449	6,552	6,664	6,786	6,919	7,063	7,048	7,034	7,019	7,004	6,989	6,973	6,958	6,942	6,927
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,175	2,349	2,537	2,740	2,959	3,196	3,452	0	0	0	0	0	0	0	0	0	0
2,175	2,349	2,537	2,740	2,959	3,196	3,452	0	0	0	0	0	0	0	0	0	0

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4,093	4,005	3,912	3,812	3,705	3,590	3,467	7,063	7,048	7,034	7,019	7,004	6,989	6,973	6,958	6,942	6,927
19,307	23,312	27,224	31,035	34,740	38,330	41,796	48,859	55,907	62,941	69,960	76,964	83,952	90,926	97,884	104,826	111,753
4,093	4,005	3,912	3,812	3,705	3,590	3,467	7,063	7,048	7,034	7,019	7,004	6,989	6,973	6,958	6,942	6,927
6,011	10,016	13,928	17,739	21,444	25,034	28,500	35,563	42,611	49,645	56,664	63,668	70,656	77,630	84,588	91,530	98,457

KENYA GEOTHERMAL PROJECT
BALANCE STATEMENT

	1995	1996	1997	1998	1999	2000	2001	2002
ASSETS:								
Construction WIP	0	0	0	0	0	0	0	0
Property, Plant & Equipment								
-Beginning Balance	66,480	63,821	61,162	58,502	55,843	53,184	50,525	47,866
-Accumulated Depreciation	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
Ending Balance	63,821	61,162	58,502	55,843	53,184	50,525	47,866	45,206
Working Capital	0	0	0	0	0	0	0	0
Debt Reserve	0	0	0	0	0	0	0	0
TOTAL ASSETS	63,821	61,162	58,502	55,843	53,184	50,525	47,866	45,206
LIABILITIES & EQUITY:								
-Long Term Debt	49,900	(3,631)	(4,016)	(4,443)	(4,917)	(5,443)	(6,027)	(2,014)
-Deferred Taxes	0	0	0	0	0	0	0	0
-Equity & Accumulated Earnings	13,921	64,793	62,518	60,286	58,101	55,968	53,893	47,220
TOTAL LIABILITIES & EQUITY	63,821	61,162	58,502	55,843	53,184	50,525	47,866	45,206

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	45,206	42,547	39,888	37,229	34,570	31,910	29,251	26,592	23,933	21,274	18,614	15,955	13,296	10,637	7,978	5,318	2,659
	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659
	42,547	39,888	37,229	34,570	31,910	29,251	26,592	23,933	21,274	18,614	15,955	13,296	10,637	7,978	5,318	2,659	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	42,547	39,888	37,229	34,570	31,910	29,251	26,592	23,933	21,274	18,614	15,955	13,296	10,637	7,978	5,318	2,659	0
	(2,175)	(2,349)	(2,537)	(2,740)	(2,959)	(3,196)	(3,452)	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	44,722	42,237	39,766	37,310	34,869	32,447	30,044	23,933	21,274	18,614	15,955	13,296	10,637	7,978	5,318	2,659	0
	42,547	39,888	37,229	34,570	31,910	29,251	26,592	23,933	21,274	18,614	15,955	13,296	10,637	7,978	5,318	2,659	0

Fixed Loan #1 (Commercial Bank)

Annual Payment:	$4,661 (If Levelized)
Grace Period	0 years
Loan Principle:	21,274
Interest Rate:	12.00%
Term:	7 years

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
		Orig. Bal.		21,274			21,274
1	payment	1995	4,661	21,274	2,109	2,553	19,165
2	payment	1996	4,661	19,165	2,362	2,300	16,803
3	payment	1997	4,661	16,803	2,645	2,016	14,158
4	payment	1998	4,661	14,158	2,962	1,699	11,196
5	payment	1999	4,661	11,196	3,318	1,344	7,878
6	payment	2000	4,661	7,878	3,716	945	4,162
7	payment	2001	4,661	4,162	4,162	499	(0)
8	paid	2002	0	0	(0)	0	0
9	paid	2003	0	0	(0)	0	0
10	paid	2004	0	0	(0)	0	0
11	paid	2005	0	0	(0)	0	0
12	paid	2006	0	0	(0)	0	0
13	paid	2007	0	0	(0)	0	0
14	paid	2008	0	0	(0)	0	0
15	paid	2009	0	0	(0)	0	0
16	paid	2010	0	0	(0)	0	0
17	paid	2011	0	0	(0)	0	0
18	paid	2012	0	0	(0)	0	0
19	paid	2013	0	0	(0)	0	0
20	paid	2014	0	0	(0)	0	0
21	paid	2015	0	0	(0)	0	0
22	paid	2016	0	0	(0)	0	0
23	paid	2017	0	0	(0)	0	0
24	paid	2018	0	0	(0)	0	0
25	paid	2019	0	0	(0)	0	0
Total:			32,630		21,274	11,356	

Fixed Loan #2 (Supplier)

Annual Payment:	$3,728 (If Levelized)
Grace Period	0
Loan Principle:	31,910
Interest Rate:	.8.00%
Term:	15 yrs

	Status		Debt Service Payment	Beg. Debt Balance	Debt Retirem't	Interest Exp.	Ending Debt Balance
			--------	-------	-------	-------	-------
		Orig. Bal.		31,910			31,910
1	payment	1995	3,728	31,910	1,175	2,553	30,735
2	payment	1996	3,728	30,735	1,269	2,459	29,466
3	payment	1997	3,728	29,466	1,371	2,357	28,095
4	payment	1998	3,728	28,095	1,480	2,248	26,615
5	payment	1999	3,728	26,615	1,599	2,129	25,016
6	payment	2000	3,728	25,016	1,727	2,001	23,289
7	payment	2001	3,728	23,289	1,865	1,863	21,424
8	payment	2002	3,728	21,424	2,014	1,714	19,410
9	payment	2003	3,728	19,410	2,175	1,553	17,234
10	payment	2004	3,728	17,234	2,349	1,379	14,885
11	payment	2005	3,728	14,885	2,537	1,191	12,348
12	payment	2006	3,728	12,348	2,740	988	9,608
13	payment	2007	3,728	9,608	2,959	769	6,648
14	payment	2008	3,728	6,648	3,196	532	3,452
15	payment	2009	3,728	3,452	3,452	276	(0)
16	paid	2010	0	0	(0)	0	0
17	paid	2011	0	0	(0)	0	0
18	paid	2012	0	0	(0)	0	0
19	paid	2013	0	0	(0)	0	0
20	paid	2014	0	0	(0)	0	0
21	paid	2015	0	0	(0)	0	0
22	paid	2016	0	0	(0)	0	0
23	paid	2017	0	0	(0)	0	0
24	paid	2018	0	0	(0)	0	0
25	paid	2019	0	0			

KENYA GEOTHERMAL PROJECT
BALANCE STATEMENT

	1994	1995	1996	1997	1998	1999	2000	2001	2002
ASSETS:									
Construction WIP	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment									
-Beginning Balance	60,680	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262
-Accumulated Depreciation	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427	2,427
Ending Balance	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835
Working Capital	0	0	0	0	0	0	0	0	0
Debt Reserve	0	0	0	0	0	0	0	0	0
TOTAL ASSETS	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835
LIABILITIES & EQUITY:									
-Long Term Debt	45,547	(3,314)	(3,665)	(4,055)	(4,488)	(4,968)	(5,501)	(1,838)	(1,986)
-Deferred Taxes	0	0	0	0	0	0	0	0	0
-Equity & Accumulated Earnings	12,706	59,140	57,063	55,026	53,032	51,085	49,191	43,100	40,821
TOTAL LIABILITIES & EQUITY	58,253	55,826	53,398	50,971	48,544	46,117	43,690	41,262	38,835

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322	8322
416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100
5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60
57.92	62.55	67.56	72.96	78.80	85.10	91.91	99.26	107.20	115.78	125.04	135.04	145.85	157.51	170.12	183.73	198.42
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302	23,302
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3,109	3,140	3,171	3,203	3,235	3,268	3,300	3,333	3,367	3,400	3,434	3,469	3,503	3,538	3,574	3,609	3,646
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
8,185	8,216	8,247	8,279	8,311	8,344	8,376	8,409	8,443	8,476	8,510	8,545	8,579	8,614	8,650	8,685	8,722
15,117	15,086	15,054	15,022	14,990	14,958	14,925	14,892	14,859	14,825	14,791	14,757	14,722	14,687	14,652	14,616	14,580
2,964	2,632	2,273	1,886	1,467	1,015	527	0	0	0	0	0	0	0	0	0	0
12,153	12,454	12,781	13,136	13,523	13,943	14,398	14,892	14,859	14,825	14,791	14,757	14,722	14,687	14,652	14,616	14,580
5,165	5,293	5,432	5,583	5,747	5,926	6,119	6,329	6,315	6,301	6,286	6,272	6,257	6,242	6,227	6,212	6,197
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5,165	5,293	5,432	5,583	5,747	5,926	6,119	6,329	6,315	6,301	6,286	6,272	6,257	6,242	6,227	6,212	6,197
6,988	7,161	7,349	7,553	7,776	8,017	8,279	8,563	8,544	8,525	8,505	8,485	8,465	8,445	8,425	8,404	8,384
12,153	12,454	12,781	13,136	13,523	13,943	14,398	14,892	14,859	14,825	14,791	14,757	14,722	14,687	14,652	14,616	14,580
5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076	5,076
(4,152)	(4,484)	(4,843)	(5,231)	(5,649)	(6,101)	(6,589)	0	0	0	0	0	0	0	0	0	0

KENYA GEOTHERMAL PROJECT
CAPITAL COST BUDGET

FACILITY COSTS:	
-Turnkey Construction	0
-Performance Bond	0
-Engineering	0
-Unidentified Scope Changes	0
-Identified Scope Changes	0
-Electrical Interconnect	0
-Contingency	0

Total Facility Costs	0
DEVELOPMENT COSTS:	
-Project Management	0
-Miscellaneous Development Costs	0
-Startup	0
-Builder's Insurance	0
-Legal	0
-Development Fee	0

Total Development Costs	0
FINANCING COSTS:	
-Engineers	0
-Bank Expenses	0
-Lendor Underwriting Fee	0
-Commitment Fee	0
-Agency Fee	0
-Consultants	0
-Title Insurance	0
-Lendor's Counsel	0

Total Financing Costs	0
Hard, Soft, & Finance Costs	126,900
Construction Interest	0
Total Expenditures	126,900
NON-DEPRECIABLE PROPERTY:	
-Working Capital	0
-Spare Parts	0
-Land	0
-Repair & Replacement Reserve	0

Total Non-Depreciable Prop	0
DEBT RESERVE	0

TOTAL PROJECT COSTS	126,900
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KENYA GEOTHERMAL PROJECT
SUMMARY SHEET

PROJECT IRR: 15 years	20%
PROJECT NPV @ 10 %	34.1 Million
PROJECT NPV @ 12 %	24.0 Million
PROJECT NPV @ 14 %	16.7 Million
TOTAL PROJECT COSTS: $	126.90 Million

PROJECT COST	$126.90 Million	100%	Debt
PARTNERSHIP EQUITY	$25.38 Million	20%	Equity
TERM LOAN	$101.52 Million	80%	