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PROJECT PERFORMANCE ASSESSMENT REPORT

UGANDA

THIRD POWER PROJECT (CREDIT NO. 22680-UG); AND SUPPLEMENTAL TO THIRD POWER PROJECT CREDIT (NO. 22681-UG)

June 26, 2008

Sector Evaluation Division
Independent Evaluation Group (World Bank)

Currency Equivalents (annual averages)

Currency Unit = Uganda Shilling (UGS)
(Exchange Rate Effective End Q2, 2006)
US$1.00 UGS 1841
1.00 UGS US$ 0.00054

1990	US$1.00	UGS 428	1999	US$1.00	UGS 1455
1991	US$1.00	UGS 734	2000	US$1.00	UGS 1644
1992	US$1.00	UGS 1134	2001	US$1.00	UGS 1756
1993	US$1.00	UGS 1195	2002	US$1.00	UGS 1798
1994	US$1.00	UGS 980	2003	US$1.00	UGS 1964
1995	US$1.00	UGS 969	2004	US$1.00	UGS 1810
1996	US$1.00	UGS 1046	2005	US$1.00	UGS 1780
1997	US$1.00	UGS 1083	2006	US$1.00	UGS 1837
1998	US$1.00	UGS 1240			(AvgQ1/Q3)

Abbreviations and Acronyms

AfDB	African Development Bank
CAS	Country Assistance Strategy
CIDA	Canadian International Development Agency
DANIDA	Danish International Development Agency
DCA	Development Credit Agreement
DRB	Disputes Review Board
DRIC	Divestiture and Reform Implementation Committee
EIB	European Investment Bank
ERT	Energy for Rural Transformation
ERA	Electricity Regulatory Agency
GOU	Government of Uganda
ICB	International Competitive Bidding
IDA	International Development Association
IPP	Independent Power Producer
MEMD	Ministry of Energy and Mineral Development
MIS	Management Information System
MNR	Ministry of Natural Resources (now MEMD)
MFED	Ministry of Finance, Planning and Economic Development
MoJ	Ministry of Justice
NDF	Nordic Development Fund
NGO	Non-Governmental Organization
NORAD	Norwegian Agency for Development Assistance
NTC	Norwegian Trade Council
ODA	Overseas Development Agency
OF	Owen Falls (now Nalubaale)
OFE	Owen Falls Extension (now Kiira)
PEAP	Poverty Eradication Action Plan
PPF	Project Preparation Facility
PTC	Privatization Technical Committee
PURSP	Public Utilities Reform Support Project
SAR	Staff Appraisal Report
SIDA	Swedish International Development Agency
UEB	Uganda Electricity Board
UNDP	United Nations Development Program
URU	Utility Reform Unit

Fiscal Year

Government: January 1 —December 31

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About this Report

The Independent Evaluation Group assesses the programs and activities of the World Bank for two purposes: first, to ensure the integrity of the Bank's self-evaluation process and to verify that the Bank's work is producing the expected results, and second, to help develop improved directions, policies, and procedures through the dissemination of lessons drawn from experience. As part of this work, IEGWB annually assesses about 25 percent of the Bank's lending operations through field work. In selecting operations for assessment, preference is given to those that are innovative, large, or complex; those that are relevant to upcoming studies or country evaluations; those for which Executive Directors or Bank management have requested assessments; and those that are likely to generate important lessons.

To prepare a Project Performance Assessment Report (PPAR), IEGWB staff examine project files and other documents, interview operational staff, visit the borrowing country to discuss the operation with the government, and other in-country stakeholders, and interview Bank staff and other donor agency staff both at headquarters and in local offices as appropriate.

Each PPAR is subject to internal IEGWB peer review, Panel review, and management approval. Once cleared internally, the PPAR is commented on by the responsible Bank department. IEGWB incorporates the comments as relevant. The completed PPAR is then sent to the borrower for review; the borrowers' comments are attached to the document that is sent to the Bank's Board of Executive Directors. After an assessment report has been sent to the Board, it is disclosed to the public.

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Risk to Development Outcome: The risk, at the time of evaluation, that development outcomes (or expected outcomes) will not be maintained (or realized). *Possible ratings for Risk to Development Outcome:* High Significant, Moderate, Negligible to Low, Not Evaluable.

Bank Performance: The extent to which services provided by the Bank ensured quality at entry of the operation and supported effective implementation through appropriate supervision (including ensuring adequate transition arrangements for regular operation of supported activities after loan/credit closing, toward the achievement of development outcomes. The rating has two dimensions: quality at entry and quality of supervision. *Possible ratings for Bank Performance:* Highly Satisfactory, Satisfactory, Moderately Satisfactory, Moderately Unsatisfactory, Unsatisfactory, Highly Unsatisfactory.

Borrower Performance: The extent to which the borrower (including the government and implementing agency or agencies) ensured quality of preparation and implementation, and complied with covenants and agreements, toward the achievement of development outcomes. The rating has two dimensions: government performance and implementing agency (ies) performance. *Possible ratings for Borrower Performance:* Highly Satisfactory, Satisfactory, Moderately Satisfactory, Moderately Unsatisfactory, Unsatisfactory, Highly Unsatisfactory.

Contents

This report was prepared by Mr. Mohammad Farhandi, Consultant, who assessed the project in August 2006. Ms. Marie Charles provided administrative support.

Principal Ratings

	*ICR**	*ICR Review**	*PPAR*
Outcome	Satisfactory	Moderately Unsatisfactory	Unsatisfactory
Institutional Development Impact**	Modest	Negligible	———
Risk to Development Outcome	———	———	Significant
Sustainability***	Likely	Unlikely	———
Bank Performance	Satisfactory	Unsatisfactory	Unsatisfactory
Borrower Performance	Satisfactory	Unsatisfactory	Moderately Unsatisfactory

* The Implementation Completion Report (ICR) is a self-evaluation by the responsible Bank department. The ICR Review is an intermediate IEGWB product that seeks to independently verify the findings of the ICR.
**As of July 1, 2006, Institutional Development Impact is assessed as part of the Outcome rating.
***As of July 1, 2006, Sustainability has been replaced by Risk to Development Outcome. As the scales are different, the ratings are not directly comparable.

Key Staff Responsible

Project	*Task Manager/Leader*	*Division Chief/ Sector Director*	*Country Director*
Appraisal	Anthony Sparkes	Robert Hindle	Callisto Madavo
Completion	Reynold Duncan	M. Covindassamy	Judy O'Connor

Preface

This is a Project Performance Assessment Report (PPAR) for Uganda's Power III project and its Supplementary Credit. The Power III project was approved for a Credit of SDR86.9 million ($125 million equivalent) on June 13, 1991 and became effective on October 8, 1992. The Credit was closed on December 31, 2001, and $4 million was cancelled. The Supplementary Credit, in an amount of SDR24 million ($33 million) was approved on January 20, 2000, and became effective on March 21, 2000. The Credit was closed on December 31, 2001, and $10 million was cancelled.

The PPAR draws on the Staff Appraisal Report (Report No. 9153-UG of May 29, 1991), the Implementation Completion Report (Report No.24406 of June 27, 2002), and other related documents. It also presents the findings of an Independent Evaluation Group (IEG) mission to Uganda. The mission met with sector officials, including the Minister and Permanent Secretary of the Ministry of Energy and Mineral Development, the Permanent Secretary and the Director of Privatization of the Ministry of Finance, Planning and Economic Development, the Chief Executive of the Electricity Regulatory Authority, the Managing Directors of Generation, Transmission and Distribution companies, as well as the concession holding companies for generation (ESKOM) and distribution (Umeme), and the Executive Director of the Rural Electrification Agency. The cooperation and assistance of the government and energy sector officials is gratefully acknowledged.

This assessment was undertaken for three main reasons. First, Uganda's electricity supply is in a dismal state, partly due to the continuing drop in the water level in Lake Victoria, which has reduced the ability to respond to power demand –as only 120 MW from the 380 MW installed capacity is currently usable. Second, the design and implementation of the project had multiple major problems, including nonperformance of the national utility (UEB), risk assessment issue, a cost overrun of about $26 million for the civil works, and a delay of more than four years in project completion. Third, Regional Operations and IEG disagreed on the performance ratings for the project at completion. This assessment intends to shed some light on these issues, mainly to draw lessons from the Bank experience that could help the design of future sector operations and to discern a way forward.

Following standard procedures, copies of the draft PPAR were sent to government officials and agencies for review and comments but none were received.

Summary

The economic performance of Uganda over the past two decades has been strong. However, poverty, though reduced, still remains very high, particularly in rural areas. The high level of poverty and lackluster private sector interest, together with a high population growth rate (averaging 3.2 percent between 1991 and 2006), have affected the performance of the power sector. Demand is increasing rapidly, the affordability of electricity has become a major issue, and the absence of major private investment has heavily burdened the government's finances in the form of direct or contingent liabilities.

Uganda is poorly endowed with hydrocarbon resources and its landlocked location adds substantial costs to the importation of energy, particularly for petroleum products. The country has almost no oil, gas, or coal reserves and its commercial energy resources are limited to hydropower and some untapped geothermal potential. Hydropower is heavily dependent on Lake Victoria, whose level has been declining rapidly and is now so low that only less than a third of the installed capacity is usable.

As a result of all these circumstances, increased access to reliable and affordable electricity supply has been at best marginal in Uganda. Today less than 4 percent of the total population (and less than 1 percent of rural population) has access to electricity, but the supply is unreliable and of poor quality.

The Uganda Power III project and its Supplemental Credit, approved in 1991 and 2000 respectively, aimed to enhance the performance of the state utility and to expand generation capacity. The quality of the project at entry was weak, which affected its implementation and, ultimately, project outcome. The project design was unrealistic about the level of tariff the market would bear and about the benefits to utility performance that would accrue from an expected improvement in the utility's rate of return. Further, the project appraisal had identified the criticality of the hydrological risk related to the water level in Lake Victoria, but concluded that the likelihood of this risk was less than 1 percent. That risk has now been realized.

While the project delivered many of its physical outputs, the achievement of the key developmental objective—to enhance the performance of the state utility—was negligible. The key financial covenants were not met during the entire 10-year project implementation period, and arrears climbed. The state utility (UEB) ultimately was dissolved and the sector was restructured. The efficiency of the project in meeting its performance targets was negligible, as system losses have continued to be high. Based on current utilization of the project's assets, the EIRR is below the opportunity cost of capital. Also, the project suffered from a completion delay of more than four years as well as substantial cost overruns due to the need for rebidding the civil works contract. Thus, the **Outcome** of the project is rated **unsatisfactory**. In the end, UEB succumbed under the weight of its poor financial performance, escalating arrears, high system losses, and other inefficiencies.

During its remaining economic life, the project will continue to face major uncertainties. Among these are the hydrological behavior of the Lake Victoria and the financial viability of the sector. Thus the **Risk to Development Outcome** is rated **significant**.

The quality at entry is rated highly unsatisfactory based on unrealistic expectations on the financial improvement of UEB, inadequate analysis of risks and the lack of readiness of the project for approval. The Bank's supervision of the project was moderately satisfactory, with the supervision

efforts being focused on implementing the project "as is." No innovative or adaptive measures were introduced to restructure or formally change the objective(s) of the project, in spite of numerous implementation issues. Further, the Bank should have more carefully scrutinized the qualifications of the main contractor, who had to be terminated due to its inadequate qualification, resulting in substantial delays and cost overruns. In light of these shortcomings and of the above-mentioned weak quality at entry, overall **Bank Performance** is therefore rated **unsatisfactory** during the implementation period of the project (1991-2001).

Overall **Borrower Performance** (combining that of the government and of the implementing agency) is rated as **moderately unsatisfactory,** given the context in which they operated, including their limited institutional capacity.

Among the lessons emerging from this assessment are:

- ❖ Power sector reforms need to be very country-specific in order to produce improved sector performance and increased access to electricity by the poor. The Bank's power sector policy and lending strategies of the1990s, with their strong emphasis on unbundling and privatization, did not lead to better performance of the sector and increased access, because they were not applied with due consideration to the country's characteristics.
- ❖ Private sector participation in major power projects can create significant contingent liabilities for the governments. Therefore, the Bank needs to encourage and help governments to develop an appropriate framework for risk sharing with the private sector.
- ❖ The Bank needs to carefully scrutinize contractor prequalification. In some cases, the Bank might be better off using the services of outside consulting firms instead of relying on its own expertise.
- ❖ Timely midterm reviews (and project restructuring if warranted) are particularly important in infrastructure projects with long implementation periods during which the original objectives and project design are more likely to require changes.
- ❖ Conditions for effectiveness and disbursement need to be minimized. In the event that a condition for disbursement is necessary, the condition should be designed such that failure to comply does not delay the project's implementation or jeopardize its overall viability.

Uganda's power sector is in a critical situation and the options available to it over the next 15 to 20 years are mostly unattractive. The sector is facing a complex set of issues that will take considerable time and effort to overcome. Further, the trade-offs among various alternatives have substantial economic, social, and environmental implications. These have produced a daunting task for policy makers.

As the sector embarks on a new strategy, including the recent approval of the re-designed (and Bank-supported) Bujagali Hydropower project, the sobering lessons from the experience of this project should be borne in mind.

Vinod Thomas
Director-General
Evaluation

1. Introduction and Context

Introduction

1.1 For the past 20 years the Bank has been continuously involved in Uganda's power sector, including through several lending operations. The Bank-supported projects (Power II [approved in March 1985], and Power III, Supplementary Credit, and Power IV [closed in December 2006][1]) were closely linked to one another—their implementation periods overlapped and the primary objective of each was to increase the electricity generation capacity at the Owen Falls at Lake Victoria.[2] This PPAR only assesses the performance of the Power III project and its Supplementary Credit. The two projects are treated as one because the Supplementary Credit was primarily to finance the cost overrun of the civil works contract under the Power III project. The Power II project was excluded from the assessment because its main activities were too far in the past, and the Power IV project was excluded because it had not closed at the time of the assessment.

1.2 Increased access to reliable and affordable electricity supply has been at best marginal in Uganda. Today less than 4 percent of the total population (and less than 1 percent of rural population) has access to electricity, but the supply is unreliable and of poor quality.

Economic Performance, Development Priorities, and Assistance Strategies

1.3 Uganda was one of the most promising countries in Africa at its independence in 1962 and it continued to prosper until 1971. However, between 1971 and 1986 its economy declined sharply due to political turmoil and internal strife. In 1987, the National Resistance Movement (NRM) took control and launched the Economic Recovery Plan (ERP). Economic growth, which had been less than 1 percent in 1970s and early 1980s, rose to average 5 percent between 1987 and 1992, although inflation was still about 65 percent and the reforms proceeded slowly. Growth accelerated between 1992 and 2002 to average 6.3 percent over the period.

1.4 The government's development priorities since the mid-1980s have focused on reducing poverty, ensuring that economic growth would be sustained, and that the benefits of that growth would be more evenly distributed than they had been in the past. The government articulated these priorities in a series of Poverty Eradication Action Plans (PEAPs) starting in 1995.

1.5 World Bank assistance to Uganda has been defined through four Country Assistance Strategies (CASs), summarized in Box 1.

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1. The Bank also financed the Power I project, approved in March 1961 and closed in March 1964.

2. In 2000, the government formally changed the name of Owen Falls to Nalubaale and changed the Owen Falls Extension to Kiira. Bujagali is about 7 kilometers downstream of the Nalubaale dam.

Box 1. Country Assistance Strategies, 1995-Present

The Banks' first full CAS was approved in June 1995 and covered FY95-98. This CAS focused on increased investment by the private sector to stimulate rapid growth and thereby to reduce poverty. While the performance of the economy during this CAS period was good, poverty remained high (60-70 percent). While the share of the private investment rose from 8.2 percent of GDP in FY87-FY93 to 11.7 percent in FY94-FY96, the share of foreign investment remained insignificant.

The second full CAS (approved in April 1997) covered FY98-FY01. It continued to focus on economic growth and poverty reduction. The economy grew at 6.9 percent and inflation declined to virtually nil by 1999. Poverty remained high, however. Improvement in the performance of the state utilities, including the power sector, was also an objective of this CAS, in particular by increasing private sector participation, competition, and regulation. Despite some progress in reform and privatization during the CAS period, investors did not show an interest in investing in Uganda's major infrastructure projects.

The third full CAS was prepared during the latter part of 2000 and covered FY01-FY03. The objective was to support Uganda's economic transformation and poverty reduction strategy as outlined in the PEAP (and the PRSP), by maintaining macroeconomic stability with an emphasis on the sectoral level. The fourth (and most recent) CAS was a Joint Assistance Strategy (JAS) prepared together with seven other development partners in the latter part of 2005 and it covered FY05-FY09. The economy has continued to grow, averaging 5.4 percent over the most recent five years.

1.6 Overall, Uganda has experienced strong growth over the past two decades, but though poverty has been reduced it is still very high, especially in the rural areas, and poverty disparities have widened since the mid-1980s. The government's ambitious plan to reduce poverty to 10 percent by 2017 now seems unrealistic. Further, private investors have shown little interest in Uganda. The disappointing results on poverty reduction and the stimulation of private sector investment, together with a high population growth rate (averaging 3.2 percent between 1991 and 2006), have affected the performance of the power sector. Demand is increasing rapidly, the affordability of electricity has become a major issue, and the absence of major private investment has heavily burdened the government's finances.

Sectoral Context

1.7 Uganda is poorly endowed with hydrocarbon resources and its landlocked location adds substantial costs to imported energy, particularly petroleum products. The country has no oil[3], gas, or coal reserves, and its commercial energy resources are limited to hydropower and some untapped solar, wind, and geothermal potential.[4] Biomass—the most important energy resource in Uganda—accounts for over 90 percent of the country's energy consumption. Biomass meets the cooking and heating needs of the majority of Ugandan households as well as the commercial requirements of small and medium enterprises.[5]

3 The Ministry of Energy and Mineral Development reports that commercial discoveries have been made, but these have not yet been developed.

4. The geothermal potential is estimated at 450 MW, but there is no commercial production.

5. ESMAP estimated wood fuel consumption of 13.6 million tons versus a sustainable yield of 10.9 million tons per year.

Consequently, the Ministry of Energy and Mineral Development (MEMD) is supporting reforestation programs, improvements in biomass end-use efficiencies, indoor air pollution control, and biomass-based power generation including gasification. Per capita energy consumption in 1993 was 1.2 million Btu, and reached to 1.5 million Btu in 2003, compared with the average of 15.6 million Btu for Africa in 2003. The country's large hydropower potential is estimated at 2,000 MW, corresponding to a production of 12,500 GWh of electricity. The installed hydropower capacity currently is 380 MW, but the effective capacity is only 120 MW. Small hydropower sites, if developed, could add an aggregate capacity of 200 MW and serve rural communities through decentralized systems. The government has also initiated measures to promote energy efficiency and demand-side management.

1.8 **Government Strategy.** The government's strategy for the power sector was articulated in the MEMD paper submitted in September 1989. The strategy, based on development of a least-cost supply to meet the demand, was to increase the hydropower capacity, accelerate electrification, increase the export of the electricity to neighboring countries and increase the autonomy of the Uganda Electricity Board (UEB). This broad strategy remained in effect until June 1999, when the government, faced with increasing UEB performance problems, approved the Power Sector Restructuring and Privatization strategy (para.3.5).

1.9 **Bank Sectoral Strategy and Support.** Despite the Bank's extended involvement in Uganda's energy sector, it had no cohesive, free-standing energy sector strategy for Uganda during the project's 10-year implementation.[6]

1.10 The Bank's first Country Assistance Strategy (Box 1) included only the ongoing Power III project and the preparation of an energy sector assessment in FY95. During the third CAS, the electricity situation had become critical as frequent load shedding, power failures, and voltage fluctuations had forced many to invest in private generation. This CAS therefore prominently emphasized the power sector and included three power projects: Power IV ($58 million), Energy for Rural Transformation ($30 million), and Bujagali ($100 million). Further, the CAS identified power and transportation as the two priority sectors for infrastructure improvement.[7]

1.11 The Bank's support for Uganda's energy sector has been extensive and sustained. The first power sector loan, for $8.4 million, was approved in March 1961, a year before the

6. Several energy-related studies were conducted after appraisal of the project, including ESMAP's Energy Assessment and Rural Energy Strategy in 1996 and 1999. Each articulated some aspects of the sector's issues. The Energy Assessment study provided a broad direction for the electricity sector—the need for institutional change, participation by the private sector, expansion of system capacity, and widening access to electricity. The Rural Electrification study suggested an approach that would achieve a high level of electrification without government, donor, or national utility investments.

7. Although power sector priorities were outlined in the CAS, there was no mention of energy or the power sector in the "progress with Sector Plans for Implementing the PEAP," though there were specific references to roads, rural development, education, health, water, and other sectors. Further, while the CAS stated that access to energy was the key constraint to rural development, no target was set for rural energy.

country's independence, to support the extension of transmission and distribution facilities. Then, in 1984, the Bank supported the first energy assessment of the country. Since then, the Bank has been continuously involved in Uganda's power sector through four power sector loans and a supplementary credit, energy for rural transformation project, Bujagali hydro project (cancelled), a petroleum exploration promotion project, as well as many energy-related studies. The Bank has lent a total of about $350 million to Uganda's power sector since 1984. Annex C1 lists the Bank's energy-related activities in Uganda.

1.12 **Donors' Support**. Many bilateral donors have been (and continue to be) involved in Uganda's energy sector including the British, Danish, Finnish, Japanese, Norwegian, Swedish, and Swiss aid agencies, as well as multilaterals including African Development Bank and Islamic Development Bank. Annex C2 provides the list of the donors and the amount of the grant /loan provided by each for the energy sector.

2. The Project

Objectives

2.1 The Bank's appraisal report did not provide specific objectives for the Power III project. However, since the project was part of UEB's five-year (1992-96) investment program, the objectives of that program are pertinent. The investment program was to continue and build upon the rehabilitation work undertaken by the Power II project to prevent power supply bottlenecks.[8] Specifically, it was to (a) provide urgently needed least-cost capacity additions to Uganda's power generation, (b) increase the safety of the Owen Falls dam, and (c) expand the transmission and distribution facilities "to satisfy the requirements of all the productive sectors of the economy." The program was also to (d) enhance the utility's operating and management capability and improve its financial performance through policy reforms and institutional strengthening which, among other things, include (i) the establishment of realistic tariffs, (ii) agreement on a sector investment program, and (iii) a link with a utility of a developed country to provide technical and practical on-site and overseas training and experience in modern practices in plant routine and preventive maintenance and operation, load forecasting and planning, accounting and computer procedures, and managerial skills. The program objectives were not revised during project's implementation.

2.2 The objectives of Power III as stated in the Credit Agreement were to (a) assist the borrower with the continued rehabilitation of the power system in Uganda; and (b) develop its hydropower resources and expand the transmission and distribution system, to provide reliable, least-cost energy to Uganda's growing population. These objectives remained unchanged for

8. The objective of the Power II project was to "prevent the development of a bottleneck in power supplies." This was to be achieved through upgrading and rehabilitating existing generation capacity at the Owen Falls power station and the capacity of the existing transmission and distribution system. The project had also the objective of strengthening UEB's operational capability.

the Supplementary Credit that was approved eight years later.[9] Although the project's objectives were stated somewhat differently in different documents, the thrust basically remain unchanged from the four objectives outlined for the overall program.

Origin, Description, and Components

2.3 Power III originated from a 1990 feasibility study funded under the Power II project. The study concluded that the next component in the least-cost expansion program of Uganda's power generation development should be a 102 MW extension of the Owen Falls plant to utilize the energy resources available from the high water levels in Lake Victoria that had prevailed since 1960s.

2.4 The main components of the project were (see Annex C3 for a full listing of the components of the program);

(a) Civil works associated with the construction of a canal (which begins at the existing Owen Falls dam and terminates ¾ kilometers downstream at the new extension dam where the new power plants are housed), the extension dam, and spillway.
(b) New power generation equipment and facilities at the Owen Falls Extension (OFE) dam, consisting of three turbo-generator units of 34 MW each (i.e., 3X34MW), and a double circuit 132 kV transmission line about one kilometer long to connect the new powerhouse to UEB's grid at the existing dam.
(c) Employment of consultants and.a panel of dam experts to advise on the condition of the existing Owen Falls dam, and the measures to strengthen the stability of the existing dam.
(d) Institution-building activities including a training workshop and provision of associated training equipment, a four-year technical assistance link with an established overseas electricity utility to provide training and experience in the areas of operations, financial control, management systems, and modern methods of routine maintenance, and training; other technical assistance and in-house and overseas training for UEB employees.
(e) Support to the Ministry of Energy; and engineering design for the next hydro site to be developed in Uganda's least-cost power development plan.

Original Cost Estimate and Financing Arrangements

2.5 The total estimated cost of the Power III project at appraisal was $335 million, of which $300 million was foreign costs. About 93 percent ($313 million) of the total cost was for the development of the Owen Falls extension dam and strengthening of the existing dam, which included major civil works for the canal and the spillway, and the electrical and mechanical equipment associated with 3X34 MW power plants. The remaining $22 million was for technical assistance for UEB and MOE, a study for the next hydro site, and about $8

9. Since there was no project appraisal document for the Supplementary Credit, the objective of the project as stated in the MOP for the Supplementary Credit was also consistent with the legal document.

million for several small transmission and distribution components originally planned to be implemented under Power II project (see footnote 9). The Supplementary Credit was for $33 million, 87 percent of which was to finance the cost overrun of the civil works contract under the Power III project, and $3.5 million was mainly to fund technical assistance for the Ministry of Finance for restructuring the power sector. Annex C4.1 provides the detailed cost estimate and financing plan for the Power III project and Annex C4.2 provides a summary of the original cost estimate and financing arrangements for the Power III project and for the Supplementary Credit.

2.6 The total cost of the program was estimated at $450 million.[10] In addition to the Power III project's components (discussed above), the balance of $123 million in the program included $100 million for transmission and distribution and $11 million for rural electrification. Thus, the entire transmission and distribution components of the program (including the transmission and distribution that were needed to transport the power generated through the project) were not included in the project financing. Annex C5 provides the cost estimates for UEB's five-year investment program for 1992-96.

On-Lending and Implementation Arrangements

2.7 The government was the borrower of both Power III (SDR equivalent of $125 million) and the Supplementary Credit (SDR equivalent of $33 million). It transferred $40 million of the Power III credit to Uganda Electricity Board (UEB) as equity, and on-lent $113.4 million to UEB on a non-concessionary basis. The balance of $4.6 million was provided to the Ministry of Energy and Ministry of Finance to fund technical assistance. UEB was responsible for project implementation and management. It was assisted by Acres of Canada, the international engineering and consulting firm that had conducted the feasibility study for the project.

Monitoring and Evaluation Design

2.8 The project had no formal provision for monitoring and evaluation. It was to be monitored through standard quarterly reports (submitted to the Bank by UEB), similar to those submitted under the Power II project. The appraisal report did include an annex (Monitoring Guidelines) that provided several performance indicators (reproduced as Annex C6 of this report).

Risk Assessment

2.9 The project's risks, according to the appraisal report, consisted of (a) hydrological risks (the risk that the water level of Lake Victoria could recede to the low level prevailing between 1900 and 1961); and (b) institutional and financial risks, considering that the improvements made to UEB's poor operating and financial performance and management

10. The total cost of the program is shown as $458 million. This includes $8.1 million for several small transmission and distribution works, mainly 33 and 11 kilovolt facilities, which could not be completed under Power II due to shortage of funds, and therefore were refinanced under Power III.

control under the Power II project were still precarious. The appraisal report had concluded that the hydrological risks would be less than 1 percent, and the institutional and financial risks could be mitigated through various covenants.

Quality of the Project at Entry

2.10 The quality of the project at entry had major shortcomings. These included an unrealistic target for tariff increases; unrealistic expectations on the contribution of an improved rate of return (had such an ROR been achieved) to enhancing the performance of the UEB; weak analysis of the probability that the single most critical risk of the project would occur; inadequate preparation of the project prior to its approval by the Board; and absence of any requirement for a midterm review. Considering the negative impacts of these shortcomings on project implementation—and, as a result, on the project outcome—these are each discussed in more detail below.

2.11 **Tariff, Rate of Return, and UEB Finances**. The project design was unrealistic with respect to the level of tariff the market would bear and the expected benefits that would accrue from an improved (8 percent) rate of return. The likelihood that the related covenants would succeed should have been more carefully considered in light of the fact that similar covenants had been required under Power II (already six years into implementation) and were falling short of their targets as the project approached its close.[11]

2.12 **Tariff**. One of the objectives of Power III was to increase the tariff, not only to the level of economic cost[12] but to a level that would ensure an 8 percent rate of return on UEB's assets. This was to be done by raising the tariff from 2.4 cents (equivalent) per kWh at appraisal to 4.8 cents per kWh by the effectiveness date, and to 7.2 cents per kWh on January 1, 1993. Then, the tariff was to be increased at 5 percent per year, in real terms, beginning January 1, 1994, and *more, if needed, to ensure a minimum return of 8 percent on UEB's revalued assets*. Revaluation of UEB's assets was also part of the condition of effectiveness, considering that the value of those assets according to the appraisal report was only 1 percent of their worth.

2.13 The increase in tariff did not take into account a realistic assessment of its *affordability* for consumers. The appraisal had concluded that domestic (residential) consumers were willing to pay up to about 17 cents per kWh. This was based on three assumptions: (i) the electricity is used by higher-income urban residents with $3,000 per year income; (ii) electricity expenses generally represent 10 percent of household income; and (iii) an average household consumption was assumed to be 1,800 kWh per year. With respect to commercial and industrial sectors, the appraisal report had concluded that users were willing

11. Under Power II, the government was to take appropriate measures (a) to implement the necessary actions for UEB to earn a rate of return of 5 percent in 1986, 6 percent in 1987, 7 percent in 1988 and 8 percent in 1989 and thereafter; (b) to review the tariff quarterly and revise as required to earn the ROR covenanted; and (c) to collect the payments of arrears.

12. The appraisal report indicates that the long run marginal cost of electricity in Uganda in 1990 was 7 cents per kWh, based on a Bank-financed study under the Power II project.

to pay up to 19 cents per kWh and 11 cents per kWh, respectively. Therefore, in the calculation of the EIRR, the benefit stream was represented by valuing electricity at 15 cents per kWh, the weighted average of the willingness to pay figures for the three sectors.[13]

2.14 Considering the Ugandan economy of 1990—income per capita of only about $180 and a poverty rate of about 60-70 percent—the approach taken to the valuation of willingness-to-pay entails many subjective assumptions. Implicit in this valuation was that the average tariff could be raised up to 15 cents per kWh and still be affordable. In reality, this was not the case.

2.15 In January 1990 the tariff was raised to 2.4 cents per kWh, when the exchange rate was 440 Shillings to the dollar. In June 1992, when the exchange rate was 915 Shilling to the dollar, the tariff was raised to 4.8 cents per kWh in anticipation of meeting the condition of effectiveness. When the tariff was raised to 7.2 cents per kWh in July 1993, the exchange rate had declined further to 1,195 Shillings to the dollar. In effect, the average tariff to a typical Ugandan consumer had increased eightfold, from 10.5 Shilling per kWh to 86 Shillings, over a three year period, and it was expected to continue increasing at 5 percent in real terms thereafter.

2.16 As the tariff increased, so did the UEB's delinquent accounts payable (arrears) from the customers. By December 1990, as a result of the January 1990 tariff increase, arrears had climbed to UGS 3 billion and by September 1992, as a result of the second tariff increase, it had risen to UGS 14.5 billion. By September 1993, after the third tariff increase, the arrears reached UGS 22.7 billion. By that time the government was reluctant to further increase the tariff, and thus declined to implement the 5 percent annual real increase after January 1994. By August 1994, less than 25 percent of the energy billed was paid for and by 1997 the arrears climbed to UGS 60 billion even though the government had written off about UGS 11 billion in arrears. By then the Bank had concluded that UEB's financial problems were no longer a tariff issue. Although UEB launched various initiatives intended to reduce its arrears,[14] the arrears issue was not resolved until the government restructured the sector.

2.17 While establishing a "realistic tariff" level was one of the objectives of the project at appraisal, the target level was not realistic. Despite the implementation of tariff increases (except for the 5 percent annual real increase) the finances of UEB continued to deteriorate, to the point that by 1999 UEB had to be dissolved.

2.18 **Rate of Return.** The tariff was below the long run marginal cost (LRMC), so raising the tariff to that level was justified. But the main justification for the increase was to achieve a *minimum* ROR of 8 percent for UEB. Achieving the targeted 8 percent minimum ROR was considered essential to enhancing the efficiency of UEB. However, even if such an ROR had been achieved, this would not have ensured a turnaround in UEB's poor performance.

13. It also concluded that the economic value of the electricity for domestic consumers was also 15 cents per kWh.

14. Operation Thunder was launched in 1996 and Operation Omega was launched in 1997, both aimed to accelerate collections.

Improvements in UEB's finances might have helped but did not guarantee the effective management and efficient operation of the utility. Attention to other parameters would also have been needed (such as control of unit costs, improved productivity, effective budgeting and planning, and a management information system). Although the appraisal report provided some strong indicators for enhancing performance of the utility, very little was accomplished toward achieving those objectives. For example, the link with a "developed country" utility, which was meant to help enhance UEB performance, was ineffective. With respect to receivables, the only covenant was related to ensuring that the ministries and parastatals would pay their arrears to UEB, which represented less than 10 percent of UEB's total arrears.

2.19 The appraisal did not consider taking a phased approach to achieving the desired return and set out a strict schedule for meeting the target. Further, during implementation, no action was taken to adjust the rate of return to a more realistic value.

2.20 Thus, while the appraisal report had projected robust performance for UEB's future finances, including generating a large amount of internal cash and achieving an overall ROR of 7-10 percent, the project fell substantially short of meeting any of its financial objectives. During the period, UEB did not meet (or even come close to meeting) the covenanted rate of return of 8 percent, nor did it meet the debt service coverage covenant, despite an eightfold tariff increase and an equity injection of $40 million by the government. Figure 2 shows the tariff increases, the arrears, and the rate of return performance during the implementation of the project.

2.21 **Assessment of Risks**. The appraisal report identified the hydrological behavior of Lake Victoria as the most critical risk facing the project. Though the assessment of this risk (conducted by UEB's consultants, Acres) was challenged by the firm that originally constructed the Owen Falls dam (Box 2), a consultant hired by the Bank validated crucial findings by Acres that led the Bank to accept the risk. This risk has now been realized. (Annex C7 provides the Bank's recent statement on this issue).

2.22 The Bank's appointment of a third-party consultant to assess two disagreeing views regarding the future hydrological risks, was a sound approach to resolving the dispute. However, the conclusion that the Bank derived from these analyses was based on a patchwork of justifications rather than a rigorous further analysis. The main issue was the conclusion that the probability of the water level reverting to the low levels of pre-1961 was only 1 percent. Considering the potential impact of this risk on the viability of the project and the qualifications of the entities that had argued against taking this risk, the Bank should have carried out more than a brief review of the issue by an individual consultant. Further, the Bank' justification for accepting the risk was based mostly on the assumption that even under the worst scenario the EIRR would not be below 8 percent. But this EIRR was based on the assumption that the willingness-to-pay for the tariff is USc15 per kWh (paras. 2.13 & 2.14).

Box 2. Hydrological Crisis of Lake Victoria-Summary Background

Until 1990 the total generation capacity at the Owen Falls dam was 180 MW, comprising 10 units that had been upgraded from 15 MW to 18 MW each under the Power II project. In May 1990, Acres completed a feasibility study (funded under Power II) for the extension of the Owen Falls dam, concluding that the least-cost alternative for development of Uganda's power sector would be extension of the existing Owen Falls dam, increasing the capacity by 102 MW (later 200 MW). This conclusion was based on the availability of substantial additional water resources at the Lake Victoria that had "gone un-harnessed hitherto." Acres argued that the outflow from the lake recorded prior to 1961 was low, and that the actual flow prior to 1961 had been closer to twice that volume. Further, Acres questioned the accuracy of the the "Agreed Curve" (the flow rate agreed between Uganda and Egypt). However, Acres also concluded that if the future flows were at the previous levels, an extension to Owen Falls would not be justified.

Acres analyzed two scenarios: (a) a base case, which used the same average annual outflow as for the period from 1961 to 1989; and (b) a low case, which used the lowest average outflow for the period from 1899 to 1961. Acres further calculated the probability the low case would occur at less than 1 percent.

The Gibbs Company of the UK, which had designed the existing Owen Falls dam in 1948 and had vast experience in Uganda and the Nile, had previously studied the possibility of extending the Owen Falls dam in 1978 and 1986, and had concluded that the expansion of generation capacity could only be limited to an upgrade of the existing 10 units from 15 to 18 MW each. They had indicated that although the lake level had dramatically risen between 1961 and 1964, the extension was not economically justified since the long-term lake outflow would be about the same as the average outflow between 1900 and 1961. Further, Gibbs indicated that the Agreed Curve was correct.

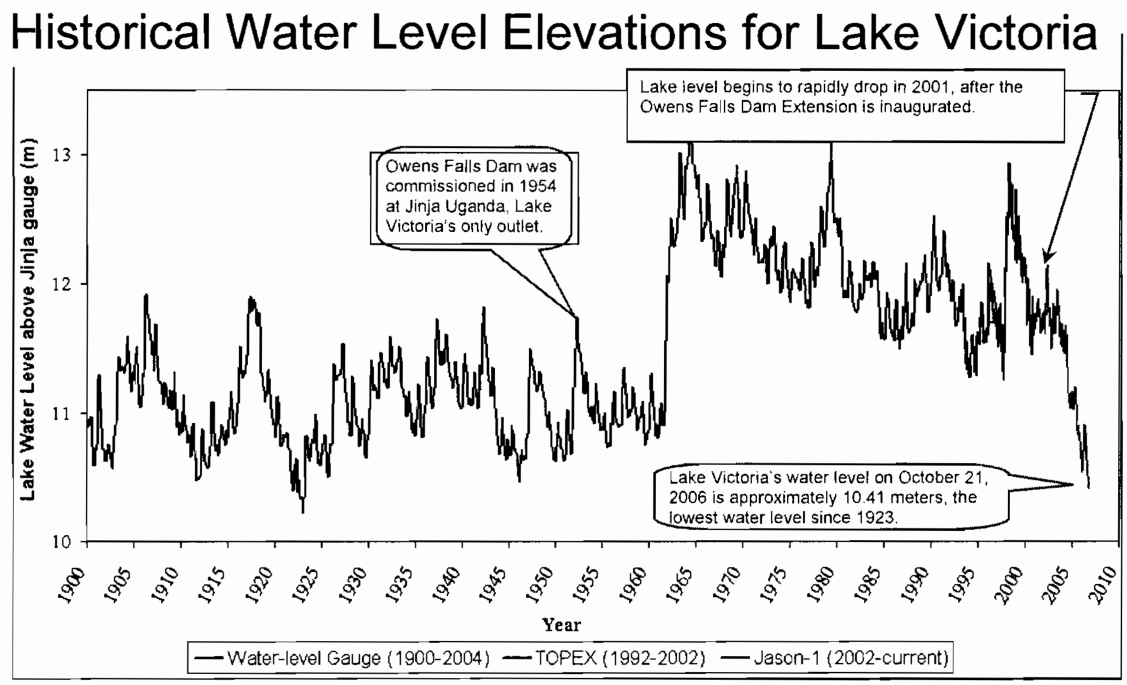
The British aid agency also asked Kennedy and Donkin to review the Acres study and in their report of July 1990, K&D indicated that the Acres "evidence is not tenable and there are significant concerns over the approach adopted by Acres. There is a real possibility that the level could go back to what was from 1900-1960. K&D do not agree that the Agreed Curve was inaccurate." Norway also raised questions about the water level in its project appraisal.

The Bank employed an individual consultant to review the discrepancies and arrive at a solution. The consultant's report of January 1991 concluded that (a) "the Agreed Curve…is confirmed; and (b) since the record of Lake levels extends from 1900 to 1990, the apparent probability that any average yearly flow will be equal to or less than the lowest value experienced is 1 to 90 or about 1.1%. Thus, the apparent probability that the lowest flows used in the firm energy analysis will be exceeded is 1/1.1 or 98.9% which is in agreement with Acres assumption of 99%."

In February 1991 the Bank concluded that (i) Acres's assertion that the pre-1960 data was in error was not correct but that (ii) the risk of reversion to the pre-1960 hydrology was small and worth taking. This was justified based on (a) even if the hydrology reverted immediately as construction began (the worst case), the project would still have an ROR of 8 percent; (b) if post-1960 hydrology persisted, the project would have a relatively short payback period of eight years, assuming a discount rate of 12 percent.

As Figure 1 shows, except for some brief intervals, the level of Lake Victoria has been dropping since it reached its highest level in 1961-64, due to drought in its catchment area and the amount of water released at Owen Falls to meet power generation requirements. At the time of the assessment mission in August 2006, only 120 MW of generating capacity was used. In October 2001, the lake reached its lowest level since 1923. The government had set a limit of 850 cubic meters per second allowable discharge (135 MW) but later had to reduce it to 750 cubic meters per second (120 MW). Currently the capacity utilization of the power plant is between 70 MW and 145 MW depending on the peak and off-peak requirements. This compares with a total of 380 MW of currently installed capacity (180 MW of which was already existing, 160 MW of which had been installed through the Power III and Power IV projects, and 40 MW of which had been installed for Unit 13 through the financing by Norway and Sweden). Unit 13 has already been withdrawn from the concessionaire to use its transformer to evacuate power from the recently installed thermal power plant.

FIGURE 1



Data Source:
Historical water level gauge data from Jinja, Uganda (near Lake Victoria's outlet).
Satellite radar altimeter data from USDA/NASA/UMD at:
http://www.pecad.fas.usda.gov/cropexplorer/global_reservoir/

U.S. Department of Agricultural (USDA)
Foreign Agricultural Service (FAS)
Impact Analysis Division (IAD)
International Production Assessment (IPA)

2.23 **Status of Preparedness**. The preparedness of the project prior to implementation was not adequate. This was evident in the number of conditions for effectiveness and disbursement, and the substantial cofinancing gaps. Further, the design of some of the key conditions was flawed.

2.24 **Conditions for Effectiveness**. There were six major conditions for effectiveness, including converting a $40 million government loan into UEB equity, doubling the tariff to 4.8 cents per kWh, revaluation of UEB's assets, evaluating the safety of the existing dam, and preparing the bidding documents to carry out the necessary work, appointment of a panel of experts, and availability of counterpart funds. The large number of conditions had the potential to prolong project implementation, add to borrower costs through additional commitment charges, and force the Bank to compromise on a condition in order to accelerate implementation. In the end, while the project was approved on June 13, 1991, the project still could not meet all the conditions of effectiveness even after 16 months and three extensions. Thus, two of the conditions were changed to conditions of disbursement, and the project became effective in October 1992.

2.25 **Conditions of Disbursement**. The project also had too many conditions for disbursement, including the availability of supplemental financing of at least $130 million (or 50 percent of the project's estimated base cost), progress in identification of another $45 million in cofinancing to fund transmission and distribution components, implementation of a resettlement action plan, as well as the two conditions of effectiveness that were added.

2.26 In addition to being too numerous, the design of some conditions was flawed. The conditions for disbursement in an investment lending operation need to be judiciously selected so that failure to meet them would not delay the entire project or put the viability of the project at risk. In this case, all of the conditions were to be met prior to disbursement for the civil works, the largest and most critical component of the project. Also, the timeframe for the activities related to the consultants for dam safety was unrealistic.

2.27 The numerous conditions did result in delays, but the overall importance of those delays was diminished by the four-year delay due to the rebidding of the civil works contract. In fact, had compliance with various conditions of disbursement been adhered to as originally required, the project would have had to start 5 years later, or by the original closing date of the project. However, by March 1994, disbursement for civil works had begun, even though some of the key conditions of disbursement had not been fully met.

2.28 **Absence of Provision for Midterm Review.** Considering the complexity of the project and the number of pending issues at entry, the design should have included a formal midterm review. The legal documents made no provision for a formal midterm review.[15]

2.29 Based on the foregoing analysis the quality of the project at entry is judged to have been highly unsatisfactory.

3. Project Implementation

Actual Costs and Financing

3.1 The total actual cost of the Power III project and the Supplementary Credit was about $313 million. The total actually disbursed by the Bank for both was $144.9 million (in original U.S. dollar amount) against the total credit of $158 million. Approximately $4 million from the Power III project and $10 million from the Supplementary Credit were cancelled. Annex C8 provides the amount of the Bank credit disbursed per category, and Annex 9 provides the amount disbursed per beneficiary. About $22 million was disbursed to beneficiaries whose names do not appear on the disbursement tables, and for which this assessment was unable to find relevant documentation.[16]

15. The Project Status Report of 6/27/1997 indicated that MTR is scheduled for 6/01/1998. The same statement appeared in the PSR of 01/29/1998, and of 06/30/1998, although there are no indications of the MTR having been carried out in June 1998 mission. The PSR of 5/14/1999 also indicated that the MTR was scheduled for 6/01/1998, and the PSR of 06/30/1999 indicated that the MTR was scheduled for 10/04/1998.

16. This should not be construed as questioning the legitimacy of the transactions or the beneficiaries; simply that at the level of this assessment the information could not be found.

Implementation Issues

3.2 **Civil Works Contract.** One of the most problematic issues during project implementation was the poor performance of the civil works contractor, Sietco of China. The cancellation of the Sietco contract, and subsequent rebidding and mobilization of a new contractor resulted in a delay of about 4 years and additional costs of $26 million. Box 3 summarizes the key events in this situation.

Box 3. Delay and Additional Costs of Civil Works Contract

In March 1992, UEB's consultant advised the Bank that 40 companies had submitted prequalification packages and recommended that 23 be accepted. In April 1992, the Bank cleared the prequalified companies and the bidding documents. Tenders were received from 13 companies. In May 1993 the Bank received the bid evaluation and recommendation proposing that the contract be awarded to Sietco, the lowest evaluated bidder (the difference between Sietco and the next higher bidder was about $15 million). The Bank provided its no objection in October 1993 and the contract with Sietco was signed in November 1993.

Sietco encountered delays and financial problems almost from the start. To help avoid further delay, the Bank agreed to advance $10 million to Sietco. However, by March 1996, some 29 months after award of the contract, the contracted works were only 26 percent complete versus a planned 70 percent. UEB finally called for new bids on January 1997, and the contract with a new contractor was signed in September 1997. An additional cost of $26 million had been incurred, and the civil works contract was only completed in 2001, about 4 years behind the original schedule.

3.3 Although responsibility for contractor prequalification remains with the borrower (and in this case, with the borrower's engineering consultants as well), the Bank should have more carefully scrutinized the qualifications of Sietco, given the importance of the civil works components and their share of the total cost and the time needed to complete the work. Further, a long time passed between when it became evident that Sietco's qualification was an issue and the time that the new contactor was selected and mobilized.

3.4 **Engineering and Construction Supervision Contract**. In 1989, UEB selected the Acres consulting firm to examine the feasibility of extending the Owen Falls dam under the Power II project. UEB (and Acres) insisted that the Bank extend Acres' initial contract under Power II to cover the detailed engineering and construction supervision of the project under Power III, without going through competitive bidding. Their argument was based on the potential delay (6 months) that could result. While the Bank agreed to extend the Acres contract until a bidder had been selected to construct the civil works, it did not agree to proceed with Acres on "single source" basis due to the size of the contract (an estimated $20 million). The contract was eventually awarded to Acres who emerged as the winning bidder from a "two envelope" competitive bid in line with the Bank's procurement guidelines for the selection of consultants.[17] By the time the contract was signed, three years had elapsed.

[17] Two-Envelope procurement is when bidders submit their bids in two envelopes: one contains the details of the bid except the price, and the other envelope contains price details. Both envelopes are submitted at the same time but the technical bid is initially opened and evaluated. The bidders which are technically responsive are notified, and the price envelopes are opened publicly.

There is no evidence that the resulting continuity with Acres helped the implementation of the project.

3.5 **Reform**. By late 1996, the government faced numerous issues stemming from UEB's poor performance and was considering a fundamental change in its approach, such as seeking a strategic partner or putting UEB under a management contract. The Bank was advising the government to move toward privatizing the sector, arguing that substantial private capital flow would lessen the government's financial burdens. The government's sector restructuring activities were in part funded through $3.5 million of technical assistance to the Ministry of Finance, a component under the Supplementary Credit.

3.6 Several positive steps in this direction were taken toward the end of the project implementation, including the passage of an Electricity Act, the establishment of a new Electricity Regulatory Authority (ERA), and the corporatization of the generation, transmission, and distribution functions (Box 4). While the Bank encouraged the government to reform the sector, it is not clear whether the new structure of the sector arose from the Bank's advice. Regardless, private sector participation in Uganda's power sector might improve technical and managerial efficiency, but it is unlikely to relieve the government of much of its financial liability. Private investors have shown very little interest in investing in Uganda's power sector without substantial government guarantees, which would subject the government to significant real or contingent liabilities.

Box 4. Sector Reform

In June 1999, the cabinet approved the Power Sector Restructuring and Privatization Strategy, and a new Electricity Act was passed in November 1999. The Act established the Electricity Regulatory Authority (ERA), which became operational in 2001. In April 2001 the government unbundled UEB's functions into generation, transmission, and distribution, and subsequently formed UEGCL, UETCL, and UEDCL respectively. UETCL was to remain a state-owned bulk single-buyer entity.

The government was reluctant to sell its assets and viewed privatization as a long-term prospect rather than an immediate solution to the problems in the sector. In November 2002, Eskom of South Africa negotiated a 20-year concession contract to lease UEGCL's generation assets under a Power Purchase Agreement (PPA). Under the terms of the PPA, UETCL is obligated to purchase capacity (MW) from Eskom on a take-or-pay basis, irrespective of the market requirements into which it has to sell, and irrespective of hydrological behavior of the Lake. Eskom is obligated to maintain generating capacity availability of 95 percent, and invest a relatively small amount ($6.8 million) and to receive a rate of return of 12 percent on this investment.

Subsequently, Eskom, in a joint venture with Globeleg of UK, formed Umeme. The new entity started operation in March 2005 and under a 20-year concession contract leased UEDCL's assets for distribution. Umeme is required to provide a minimum of 15,000 new connections per year in the first four years and then 25,000 per year thereafter, with a total investment of up to $350 million over the concession period, depending on the tariff level.

3.7 It is too early to judge the long-term sustainability of the current concession-type contracts for generation and distribution, which are presently dependent on Bank support and the government's assumption of contingent liabilities. In the distribution sector, in addition to re-lending $11 million (from the Power IV project) to finance investments in the system, the

Bank provided a Partial Risk Guarantee (PRG) of about $5.5 million (reallocating from the Privatization and Utility Sector Reform project) to Umeme, the concession holder, to mitigate electricity payment risks. Thus, the government's contingent liabilities continue to increase as Umeme will have recourse to a liquidity facility if the Uganda Distribution company defaults on its obligation. Overall, it is estimated that under current concession contracts, the government is expected to subsidize the sector for $400-$450 million over the next 4-5 years.

3.8 **Inspection Panel and Environmental Issues**. In July 2001, about 6 months before project closing, the Bank's Inspection Panel received a complaint from several NGOs[18] of failures and omissions of the project's design and implementation that negatively affected their rights and interests. The projects referred to were Power III and Bujagali. Management responded to the complaint in September 2001 and the Panel decided to launch a formal investigation and issued its investigation report in May 2002. The investigation report covered the Power III, Supplementary Credit, Power IV, and Bujagali projects. Box 5 presents the Inspection Panel findings relevant to Power III and the Supplementary Credit.

18. National Association of Professional Environmentalists of Kampala, Uganda Save Bujagali Crusade, and other local institutions.

Box 5. The Inspection Panel's Findings and the Management Response

The Panel concluded (and the Bank's Management had responded) that:

(a) Power III project should have been fully subject to OD 4.00. Nonetheless, the Panel agreed that the environmental analysis "largely accords" with the requirements of OD 4.00. However, the procedures outlined for environmental evaluation by OD 4.00 were not "complied with in regard to both the involvement of the affected groups and the use of an environmental advisory panel." It also agreed that no additional EA for the Supplementary credit would be required, given that both Power III and the Supplementary Credit had the same objectives. Thus, the Panel found the Management in partial compliance with this policy.

(b) While OMS 2.36 did not mandate the use of Sectoral Environmental Assessment (SEA), OD 4.00 of 10/31/1989 had introduced them. The project appraisal report for Power III called for SEA but it was never carried out. According to the Panel, "the failure to perform SEA for the Power III project was a violation of the terms and conditions under which the Board approved the Credit." In the Panel's view, this led directly to many of the concerns related to the Bujagali project. Management agreed to this shortcoming and stated that the rationale for not pursuing a SEA during supervision should have been documented and discussed. However, it should be noted that the project intended to carry out a SEA, and even the TOR for the SEA had been prepared and included in the project's documents.

(c) Although cumulative effects analysis was not included in the Bank's directives at the time, but since good practice required such analysis, the Panel argued that such analysis should have been carried out as part of the Power III project (i.e., to assess the potential cumulative effects of various schemes under consideration at the time). The Panel further argued that since the TOR for the SEA states that SEAs are particularly suitable for reviewing the cumulative impacts of many relative small investments which do not merit individual EA, therefore by not doing the SEA, the Management is not in compliance with OD 13.5 on project supervision.

(d) The Panel further argued that the change in the project's configuration from original 3X34 MW to 5X40 MW was not discussed at the time of the Board presentation of the project and thus did not meet the requirements of OD 10.00 on Investment Lending. The Management agreed that there should have been "a full and frank disclosure of this situation."

(e) The requesters also had asserted that Power III project was not in compliance with OP10.04 (which was issued in 1994, or over two years after the project was approved), by not including the costs of externalities in the EIRR. The Management responded that in addition to the fact that such inclusion was not required at the time, the cost of externalities were insignificant in comparison with the capital costs of the project. The Panel agreed that the OP 10.04 did not apply to Power III project but nonetheless noted that the required procedures were not observed "since the only way to confirm that the magnitudes of externality costs are significant or insignificant is to prepare and include" the estimated cost of externalities.

3.9 Although the Panel raised several valid points regarding procedural compliance, there are two substantive issues. First, the Bank neglected to follow up on the sectoral environmental assessment (SEA). The Panel found that although the Bank had prepared the TOR and allocated the budget, it did not implement the assessment. Second, the Bank failed to investigate the potential cumulative effects of other smaller schemes. Both issues, as well as lack of disclosure to the Board of changes made to project configuration, further enforce this assessment's finding regarding the poor quality of the project at entry.

4. Project Performance and Outcome

Relevance

4.1 The two project objectives related to improving the safety of the existing dam and expanding Uganda's transmission and distribution system were and continue to be relevant to the development priorities of the country and to the Bank's country and sector strategies. One of the five pillars of Uganda's most recent statement of development priorities, the 2004 PEAP, is to increase investment, including in the energy sector.

4.2 However, the key development objective—enhancing the performance of the now defunct UEB—is no longer relevant. Further, it is unclear that increasing the generation capacity at Owen Falls would remain relevant to the future development priorities of the country as the least-cost alternative. Owen Falls currently has a high level of unutilized generation capacity and it is highly uncertain that the full capacity could be utilized through the remaining economic life of the project. In addition, system losses continue to be high (35-40 percent), suggesting that extensive rehabilitation and renovation of the system's transmission and distribution network should in any case take precedence over further expansion of its capacity. (MEMD is of the view that capacity expansion is of equal importance to system loss reduction, and the two should be handled simultaneously through short- and medium-term measures.)

4.3 Considering the above, the overall relevance of the project is judged to be modest.

Efficacy

Dam Safety

4.4 Improving the safety of the existing Owen Falls dam was achieved. The problem proved to be less difficult to solve than originally envisioned. The estimated cost of this item at appraisal was about $32 million, but the actual cost was about $10 million.

Physical Objectives

4.5 **Construction of Feeder Canal, Extension Dam, and the Spillway**. This objective was achieved. This item was primarily financed by the Bank. From the total amount of $152 million disbursed by the Bank under the project, $135 million was used for this component, including for the financing of engineering and construction supervision.

4.6 **Installation of 3X34 MW Turbo-Generator Sets and Associated Equipment**. The configuration of the new power plant was changed from 3X34 MW units and the associated civil works that would have accommodated 5X34 MW units in future, to 3X40 MW and the civil works that would have accommodated 5X40 MW units in future. Norway provided cofinancing for two of the turbines (Units 11 and 12). The units were eventually installed in May 1998 and end-1999. However, Unit 13 was financed by Norway directly. Although it was scheduled to be commissioned in October 2001, it was commissioned in May 2002, about 6 months after the project close. Due to the low level of Lake Victoria, Unit 13 is no longer under the concession as its transformer is being used to evacuate power from a recently installed thermal plant.

4.7 Thus, the additional generating capacity installed under the project was only 2X40 MW (Units 11 and 12), and not 3X34 MW.[19] This objective was therefore partially achieved.

4.8 **Transmission and Distribution**. None of the transmission and distribution components described in the project appraisal report's third objective were included in the project. Rather, they were part of the program and financed directly through bilateral funding and were completed in different timeframe. Therefore, it is difficult to assume that the physical completion of these components was fully achieved as a result of the project, and as described in the project. The physical achievement of this objective therefore is not rated.

4.9 Although one of the objectives was partially achieved and one was not rated, the achievement of the physical objectives of the project is assessed to be substantial due to completion of the civil work which was an important physical component of the project.

DEVELOPMENTAL OBJECTIVES

4.10 **UEB's Performance**. UEB's finances and arrears did not improve at all under the project. The appraisal report provided two key financial covenants: (a) earning an annual rate of return of not less than 8 percent from 1993 onward; and (b) not incurring any debt unless UEB's net revenue is at least 1.5 times its debt service requirements.[20] Neither of the two covenants was met during the entire 10-year project implementation. Arrears climbed from UGS 8 billion in 1991 to UGS 69 billion in 1997. UEB was dissolved mostly as the result of its unmanageably burdensome finances, including arrears.

4.11 *Losses* continued to be high throughout the project implementation period, dropping from 40 percent in 1990 to 36 percent in 1997, but they remained at 36 percent when the project closed in 2001. Figure 2 shows the percentage of system losses, the tariffs increases, the arrears, and the ROR during project implementation.

4.12 *The number of registered customers* per employee did not improve during UEB's time. The number of UEB employee increased by 50 percent between 1991 and 1993. Further, the linking ("twinning") arrangement with a utility in a "developed country" did not prove to be effective.

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19. Units 11 and 12 currently have vibration problems, as reported by the Eskom (see Annex C10).

20. The project's monitoring targets included additional financial indicators such as operating ratio, internal cash generation requirement, debt-equity ratio, and current ratio. However, except for the current ratio, which measures the liquidity of the entity, the debt-equity ratio and debt service covenant requirements are substitutes, and therefore do not have to be used together. Likewise, the operating ratio and net internal cash generation are both revenue-type covenants, similar to the rate of return. Thus, the principal financial covenants basically were the ROR and DSCR.

4.13 **Increasing access**. The total electrification rate in Uganda is about 4 percent, with about 1 percent of the rural populations having access to electricity.[21] The increase in the number of connections during the 10 years of project implementation averaged about 5 percent. The number of customers increased from 130,000 in 1991 to 165,000 in 1997 and 200,000 in 2001. The increase was mainly in the number of urban consumers. When taking into account the persistent losses, including nontechnical losses, and the current underutilization of generation capacity, while connections have increased at 4-5 percent annually, the effective increase in access to electricity as the result of the project was marginal. The government's target is a 10 percent electrification rate by 2012. However, this is not likely to be achieved because it implies doubling the number of connections over the next six years, or adding about 50,000 connections per year, or twice the current rate—provided the generation capacity would be available.

4.14 In summary, the achievement of the developmental objectives of the project was negligible. Therefore, despite some achievement of physical objectives, the overall efficacy of the project is rated as modest.

Efficiency

4.15 The efficiency of the project in meeting its development objectives is negligible. The project failed to achieve any of its critical efficiency objectives—improvement in UEB's finances and operating and management capability, reductions in the high system losses, and increased collection of arrears. The improvement in UEB's finances fell significantly short of targets to the extent that the entity was dissolved, the system losses did not decline, and the arrears increased.

4.16 Further, the project suffered significant delays and a substantial cost overrun. The project's original closing date was June 1997 but it closed on December 2001, more than four years after the original closing date. Due to the inadequate qualifications of the main civil works contractor, and the resulting rebidding of the contract, the cost of the civil work contract increased by $26 million.

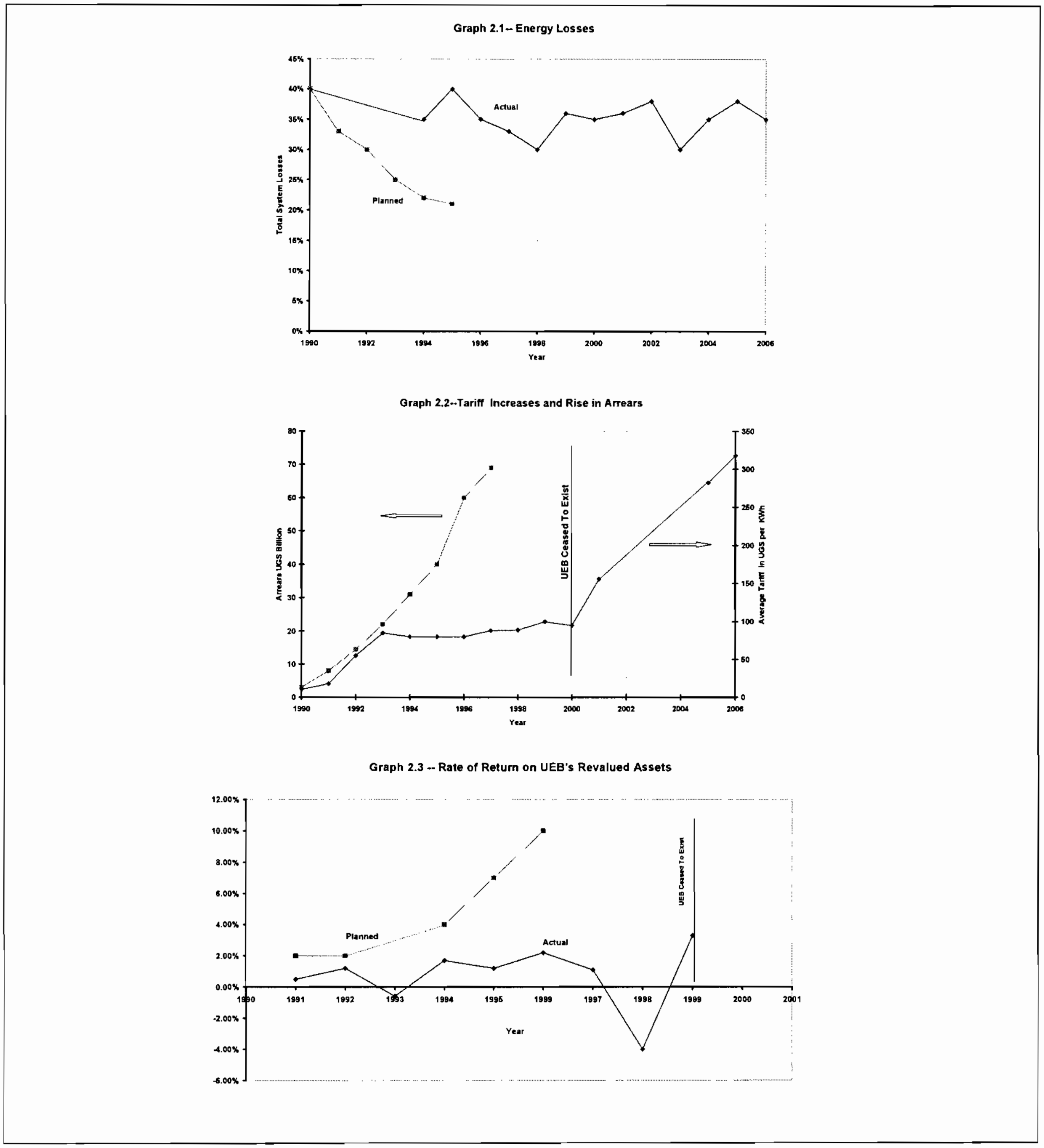
4.17 With regard to economic analysis, the calculation (or recalculation) of the EIRR would not be meaningful. If it was based on current level of asset utilization, the EIRR would be significantly below the opportunity cost of capital. Also, the future use of the project's assets is not certain given the uncertainty surrounding the future water level of Lake Victoria. The appraisal report provided an EIRR of 16.5 percent, assuming a benefit stream corresponding to the sales of electricity generated by 3x34 MW units (102 MW),[22] as well as assuming substantial decrease in system losses. However, at the time of the assessment mission the project assets were significantly underutilized, and only 120 MW from a total of 380 MW installed capacity was being used. Although units 11 and 12 (part of the project) were in operations and generating a share of the120 MW, the two units could theoretically be

21. Uganda recently has changed the number of persons in a household from six to eight people.

22. An emergency diesel unit was assumed to be the standby.

considered redundant—since the 120 MW capacity could be met by the original 10 units. Since this implicitly questions the rationale for the Kiira Power Station project, MEMD in its comments dated June 13, 2008 (see Annex C) clarified that the main consideration for increasing the capacity at Kiira was the physical condition of the Nalubaale Power Station. MEMD indicated that the 1997 Hydropower Development Master Plan gave Nalubaale a life expectancy of 25 years given its huge cracks and the movement of concrete which affects the alignment of the shafts. MEMD further clarified that the Kiira Power Station (base load plant) is a new installation meant to replace the the ageing Nalubaale Power Station (peaking power plant).

FIGURE 2.



Outcome

4.18 Based on the foregoing assessment of relevance, efficacy, and efficiency the outcome of the project is rated unsatisfactory.

4.19 The quality of the project at entry was highly unsatisfactory, and the shortcomings of its design affected its implementation. Few substantive actions were taken during implementation period to remedy the shortcomings. Moreover, it is unlikely that the shortcomings of this project will be reversed or mitigated in future in a manner sufficiently to alter the outcome of the project.

4.20 The design of the project was only modestly relevant to its development objectives, focusing almost entirely on constructing an extension dam and achieving financial soundness for UEB. Considering the high level of system losses and UEB's substantial inefficiency, the design should have focused more on reducing losses and enhancing the overall performance of UEB rather than focusing primarily on improving its finances.

4.21 The efficacy of the project was modest. Some of the key development objectives of the operation were not achieved at all. Of those that were achieved, most of them physical outputs, some were only partially achieved. The extent to which the objectives were achieved efficiently is negligible, since the system losses continued to be high.

Risk to Development Outcome

4.22 The Risk to Development Outcome is significant because of two related uncertainties that the project faces over its remaining economic life. The first is the uncertainty associated with the future hydrological behavior of Lake Victoria, and hence the water level and the usable generation capacity. On October 21, 2006, the lake reached its lowest level since 1923 (at approximately 10.41 meters). Except for some brief intervals, the water level has been continuously dropping since its highest level in 1961-64, and the drop has particularly been steep since 1999 (Figure 1). Although there has been a slight recovery very recently (the result of unusual rains in late 2006), the drop in the lake level has been persistent. The government first set the discharge level at equivalent of 135 MW generation capacity (850 cubic meters per second) but in August 2006 had to reduce it to 750 cubic meters per second, equivalent to 120 MW of continuous capacity.[23] In fact, Unit 13 has been withdrawn from the concessionaire for a period of two years to use its transformers to evacuate the power generated from the recently installed 50 MW thermal plant. It is uncertain whether the lake level could rise enough to ensure the viability of the project for the remainder of its economic life. This assessment concludes that there is significant risk that the water level will not rise enough to allow utilization of the project's assets as originally envisioned. However, in its comments (see Annex C), MEMD indicated that a very low level for Lake Victoria and a return to the low hydrology of the 1900-1960 period should not be assumed, given (a) the paucity of authoritative literature that can predict with a high degree of certainty what the lake's hydrology will be in the next half century and (b) the protracted drought of 2003-2006 which also affected Tanzania, Rwanda and Kenya.

4.23 The second uncertainty facing the project is the financial viability of the sector. To meet the electricity demand when the lake level is low, the country has to rely on thermal

23. Because of the peak and off-peak variations in electricity demand, the capacity use changes between 70 MW and 145 MW.

power generation, as currently is the case (50 MW Aggreko I and II). The cost of thermal generation in Uganda is high, and its mix with hydropower raises the level of tariff. The current tariff at about 18 cents per kWh is already high. Considering the prevailing poverty, any further tariff increase would exacerbate the affordability issue, resulting in either much lower rate of electrification, or higher nontechnical losses due to increase in the number of unregistered customers. This would further undermine the finances of the sector. Given the current concession contracts for generation and distribution, which are linked to the volume of electricity sold and the level of tariff, the government would have to assume substantial financial liabilities.

4.24 These uncertainties present significant risks to the operation of the project assets over its remaining economic life. The nature of these risks is such that it is difficult to implement cost-effective measures to mitigate or avoid them.

Bank's Performance

4.25 **Quality at Entry**. The quality at entry is rated highly unsatisfactory based on unrealistic expectations on the financial improvement of UEB, inadequate analysis of risks and the lack of readiness of the project for approval (see paras 2.10 onwards).

4.26 **Quality of Supervision**. The Bank put in considerable efforts during supervision, given the number of issues related to the quality of the project at entry, which consumed substantial supervision time. The supervision missions were regular, frequent, and well documented (Annex 11). The mission team aggressively followed up with the issues before them, and management was regularly informed of the issues. Management also actively participated in trying to resolve issues such as arrears, UEB's finances and poor performance, and project delays. Particularly notable was the Bank's encouragement of sector reforms, though those efforts came toward the end of the project with most of the reform-related activities taking place under the Power IV project.

4.27 There were two areas in which the Bank's performance during supervision fell short. First, the supervision focused on implementing the project "as is." No innovative measures were introduced to restructure the project, or formally change its objectives to mitigate or remedy the project's poor quality at entry. Even after six years of implementation, and continuously poor financial performance of UEB, poor collection records, and high losses, no consideration was given to restructuring the project, or to a comprehensive midterm review. Second, the Bank cleared the prequalification of a civil works contractor who had to be terminated due to inadequate qualifications. Although the borrower (and in this case, its engineering consultants) bears responsibility for contractor prequalification, the Bank should have more carefully scrutinized the qualifications of the contractor and should have expedited the rebidding process.

4.28 The quality of the Bank's supervision performance during the implementation of the project is rated moderately satisfactory. However, due to poor quality of the project at entry and its impact on project outcome, the Bank's overall performance for the project period as a whole (1991-2001) is assessed to be unsatisfactory.

Borrower Performance

4.29 The government raised the tariff twice, approximately within the timeframe agreed with the Bank, though it did not take the final step of increasing it by 5 percent annually in real terms. By then it had become obvious to all parties that tariff increases were not enough to overcome UEB's poor performance. Further, the government helped to improve the finances of UEB by converting $40 million of its loan to UEB into equity. Also, the government, within its capacity, facilitated the resolution of key implementation issues and its relationships with the donors were cooperative. However, the government did not provide the enabling environment to improve the collection of arrears—particularly the 10-15 percent owed to UEB by government ministries and parastatals. Thus, the government's overall performance during project preparation and implementation is rated moderately unsatisfactory.

4.30 Some of the same points apply to UEB, the implementing agency. Although UEB did not meet the agreed financial covenants, the arrears were mostly the product of an unrealistic tariff. Nonetheless, UEB should have raised concerns about (or rejected) the unrealistic financial covenants at the time of loan negotiations. Had the lessons of the Power II project been taken into account, it would have been obvious that UEB could not have met the financial covenants under the Power III project. While it can be argued that UEB must also bear some responsibility for misjudging the qualifications of the first civil works contractor, which resulted in substantial delay and cost overrun, it was difficult for UEB itself, given its weak institutional capacity, to conduct a detailed prequalification analysis, a task that should have been conducted by its engineering consultants. Taking these factors into account, the performance of the implementing agency during the preparation and implementation of the project is rated moderately unsatisfactory.

4.31 Overall Borrower performance is thus rated moderately unsatisfactory during the project's implementation period.

Monitoring and Evaluation

4.32 The project had no formal requirement for monitoring and evaluation. To the extent that M&E was carried out during implementation, it was only partial. Further, as shown in the appraisal report, the monitoring guidelines provided indicators for the period between 1990 and 1995 but the project closed in December 2001. Therefore, for half of the project's implementation period there were no monitoring or performance targets. With the dissolution of UEB, many of the indicators were rendered meaningless. The losses and ROR are shown in Figure 2.

5. Lessons and Perspectives

Lessons

5.1 The lessons emerging from this assessment are as follows:

- Power sector reforms need to be very country-specific in order to produce improved sector performance and increased access to electricity by the poor. The Bank's power sector policy and lending strategies of the1990s, with their strong emphasis on unbundling and privatization, did not lead to better performance of the sector and increased access, because they were not applied with due consideration to the country's characteristics.
- Private sector participation in major power projects can create significant contingent liabilities for the governments. Therefore, the Bank needs to encourage and help governments to develop an appropriate framework for risk sharing with the private sector.
- Risk analysis needs to be subject to a wide array of sensitivities to potential risks, rather than measuring the sensitivity only with respect to changes in the economic rate of return.
- The Bank needs to accept some responsibility for contractor prequalification. In some cases, the Bank might be better off using the services of outside consulting firms rather than relying on its own expertise.
- The project restructuring and midterm review in infrastructure projects should be used more liberally, considering that most infrastructure projects have long implementation periods during which the original objectives and project configuration could change.
- Conditions for effectiveness and disbursement need to be minimized. In the event that a condition for disbursement is necessary, design of the condition needs to be such that failure to meet it does not delay project implementation or jeopardize the project's overall viability.

Perspectives

5.2 The options available to Uganda's power sector over the next 15 to 20 years are mostly unattractive. The sector is tangled in a complex set of issues that will take considerable time and effort to overcome. Further, the trade-offs among various alternatives have substantial economic, social, and environmental implications. Against this overall dismal picture, however, it should be noted that there are generation projects at different stages of development, namely the Bujagali project, a 50-MW heavy fuel oil plant to be commissioned in October 2008, and the Kaiso Tonya 50-MW plant based on locally produced oil that is due for commissioning in 2010.

5.3 Uganda's endowment of commercial energy resources is very limited. The exploitation of its hydro resources is capital-intensive, subject to interruption by drought, and influenced by environmental and social factors. The importation of petroleum fuels is very expensive and any thermal-based power generation would result in a very high tariff. Therefore, when the hydro-based generation is supplemented with thermal-based, as currently is the case, the cost of electricity supply becomes expensive. Even if the entire generation is hydro-based, the cost of transmission and distribution is still high, considering (i) the poor conditions of the transmission and distribution assets, with technical losses ranging from 15-35 percent (average of 17 percent), and (ii) characteristics of the residential consumers, most of whom (88 percent) are rural, have low consumption levels, and who require lengthy transmission lines far from the load center. While the incremental cost of only the distribution connections for each consumer ranges from \$100-\$150, the average revenue from a typical rural household is in the order of \$2-\$3 per month.

5.4 Uganda is still one of the poorest countries in Sub-Saharan Africa and the cost of electric power is out of reach for many of its people. Despite its strong economic performance over the past two decades and poverty reduction achievements, poverty remains a persistent problem particularly in the rural areas. With income per capita of only \$280, the average tariff in Uganda is currently 18 cents per kWh, compared with average tariff of 9 cents per kWh in the United States. Considering that the average consumption in a residential household in 2006 was 1,090 kWh, the share of the electricity expense as percentage of income in a typical household is 12-13 percent, compared with 2 percent in the United States.[24] When the electricity cost represents such a high share of the income in a poor population, it results in high arrears and high nontechnical losses (17-20 percent), and slows the electrification rate.

5.5 The high cost of supply and the low level of affordability are further complicated by the major constraint on power production—the low level of water in Lake Victoria, partly due to persistent drought and partly because of increasing water drawdown for power generation. The challenge therefore is to supply electricity to a population whose average income per capita is about 4 percent of the world average income per capita, and at a price which is about twice the average world price. Policy makers face a daunting task: if the high tariff is passed on to consumers, a large segment of the population cannot afford to pay; if it is not passed on, then the government has to undertake huge financial burdens, either directly or through the private sector, to subsidize the sector.

5.6 There have been substantial discussions regarding the role of the private sector to alleviate these problems. However, it is unrealistic to expect the private sector to invest in Uganda's power sector without shifting almost all risks to the government. Private investors so far have shown little interest in Uganda's power sector. During the 10-year project implementation period (1991-2001), the foreign direct investment rose from \$50 million to \$250 million, but mostly related to projects for food and agro industries. Despite enactment of an electricity law, establishment of an energy regulatory authority, and privatization of generation and distribution, the power sector has attracted only a few investors. In fact, there was only one serious bidder for the concession contract. Even at that, the nature of both

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24. The government subsidizes the first 15 kWh at 3 cents per kWh. Considering the balance at 16 cents per kWh and the fixed monthly of about \$1.1, the average tariff is still is about 16 cents per kWh.

contracts is such that the government has to bear significant costs (estimated at $400-$450 million over the next four to five years) to sustain the power supply.

5.7 It is outside the scope of this assessment to provide detailed discussions regarding above issues or a future strategy for the sector. However, to pave the way for a viable, well-performing power sector in Uganda, elements of a strategy could include:

- Reducing the system losses. Given the current high level of losses, this would provide 50 MW to 60MW of capacity. In addition, reducing the nontechnical losses would send the correct signal to the nonpaying consumers.
- Expanding off-grid rural electrification, along the lines of some of the components of the ongoing Energy for Rural Transformation project (independent grid connection and photovoltaics), but without the expectation of vast private sector participation.[25] Other sources of concessionary financing should be pursued including substantial contribution by IDA.
- Development of a cascade-type hydro project such as Bujagali or Karuma, based on (i) a comprehensive and rigorous multisectoral study to address the optimum utilization of Lake Victoria; and (ii) a realistic framework for risk sharing between the government and the private sector; and (iii) a transparent PPA which would be publicly disclosed at the initial stages of the project.
- Creating a cadre of experts (in energy economics, financing, markets, pricing, forecasting, and institutional aspects) to support policy makers. With the concessionaires taking over the distribution and generation functions, and UEDCL and UEGCL virtually having ceased to exist, the know-how and the expertise have been dispersed. The MOE does not have the capability to address the various energy-related issues to ensure its value added involvement.
- Bringing expectations regarding the power sector's performance in line with Uganda's context, with respect to social, economic, and sectoral indicators.
- Preparing a coherent, free-standing joint (between the GOU and the Bank) energy sector strategy for Uganda that could be renewed periodically.
- Conducting a detailed assessment of the performance of the Power IV project.

[25] The MEMD clarified (see Annex C) that construction of small hydropower plants with an aggregate capacity of 40 MW is underway, as well as power sales from three sugar mills to the grid, all by the private sector. Discussions on the Karuma Hydropower Project (a public-private partnership) are also underway.

Annex A. Basic Data Sheet

THIRD POWER (CREDIT NO. 22680-UG); AND SUPPLEMENTAL CREDIT NO. 22681-UG

Key Project Data *(amounts in US$ million)*

	Appraisal estimate	*Actual or current estimate*	*Actual as % of appraisal estimate*
Total project costs	335	313	0.93
Loan amount	125	158	1.27
Cofinancing	210	168	0.80
Cancellation	--	13	--
Institutional performance	see text	see text	see text

Project Dates

	Original	*Actual*
Initiating memorandum	--	--
Negotiations	--	29/05/91 & 21/12/99
Board approval	--	13/06/91 & 20/01/00
Signing	--	09/01/92 & 22/02/00
Effectiveness	09/04/92	08/10/92 & 21/03/00
Closing date	30/06/97	12/31/01 & 12/31/01

Staff Inputs (staff weeks)

	Actual	
	N° Staff weeks	*USUS('000)*
Preappraisal	64.2	147.6
Appraisal/Negotiation	28.9	68
Supervision	243.95	779.8
ICR	8.42	26.2
Total	345.47	1021.6

Mission Data

	Date (month/year)	No. of persons	Staff days in field	Specializations represented	Performance Rating: Implementation Progress	Performance Rating: Development Objective
Identification/ Preparation	March 1990	4		SPE, SFA, ES, OA		
Appraisal	June 1990	4		SPE, SFA, ES, OA		
Supervision	August 1991 (initial summary)	1		PE	S	S
	June 1992	1		SPE	S	HS
	August 1992	1		SPE	HS	HS
	Update September 1992	1		SPE, FA, FA	S	S
	December 1992	3		SPE, FA, FA	S	S
	June 1993	2		SPE, FA	S	HS
	Update September 1993	2		SPE, FA	S	HS
	December 1993	3		SPE, FA, EA	S	HS
	March 1994	2		PFA, EA	S	HS
	Update September 1994	0			S	S
	December 1994	2		EE, SFA	S	S
	Update June 1995	2		EE, SFA	S	S
	July 1995	2		EE, SFA	S	S
	April 1996	1		EE	U	U
	October 1996	2		EE, SFA	U	U
	June 1997	1		PE	U	U
	Update July 1997	0			U	U
	January 1998	2		PE, SFA	S	S
	June 1998	1		PE	S	S

Date (month/year)	No. of persons	Staff days in field	Specializations represented	Performance Rating	
				Implementation Progress	Development Objective
February 1999	1		PE	S	U
May 1999	1		PE	S	U
June 1999	3		PE, PE, LS	S	U
December 1999	2		SES, PE	S	S
Update April 2000	0			S	S
August 2000	2		SFA, PE	S	S
Update March 2001	1		SPE	S	S
June 2001	1		SPE	S	S
December 2001	4		SPE, EC, FA, FMS	S	S
Update December 2001	0			S	S
Completion					

PE = Power Engineer; SPE = Senior Power Engineer; FA = Financial Analyst/Financial Assistant; EE = Electrical Engineer; SFA = Senior Financial Analyst; EA = Energy Advisor; PFA = Principal Financial Analyst; LA = Lead Specialist; SES = Senior Environmental Specialist; EC = Energy Economist; FMS = Financial Management Specialist; ES = Environmental Specialist; OA = Operations Analyst

Other Project Data

Borrower/Executing Agency: GOU

FOLLOW-ON OPERATIONS

Operation	Credit no.	Amount (US$ million)	Board date
Power IV Project	CR-3545-UG	70	July 03, 2001
Energy for Rural Transformation	P069996	$12 million Plus GEF	December 13, 2001

Annex B1—List of Documents Reviewed and Bank's Energy-Related Activities

1. Power Project (P002894) ----1961
2. Energy Assessment Report---1983
3. Power project II (P002917) ---1985
4. Petroleum Exploration Promotion project (P3919) ---1985
5. Power System Efficiency Study (ESM92) ---1988
6. Power project III-Original (P002929) ----1991
7. Kikagati Mini-hydro Rehab project Study---1992
8. Country Assistance Strategy---1993
9. Country Assistance Strategy---1994
10. Country Assistance Strategy (14460-UG) ---1995
11. Petroleum Exploration Promotion --- 1995
12. Power project II --Completion Report (PCR# 15194)---1995
13. Energy Assessment ---ESMAP Report #ESM193---1996
14. Country Assistance Strategy (16540-UG) ---1997
15. Rural Electrification Strategy---ESMAP Report No. ESM221-1999
16. Power project III—Supplemental (P069840)---2000
17. Power III –Supplemental-DCA and PA Amendment---2000
18. Privatization and Utility Sector Reform -- (Report 20016)--2000
19 Report on Power Sector Reform and Regulation Strategy Workshop---2000
20. Country Assistance Evaluation and Stakeholders Voices ---2000
21. Supplementary Credit Relating to the Impact of Oil Prices on Africa---2000
22. Country Assistance Strategy (20886-UG) ---2000
23. Power project IV (P002984)--CR-3545-UG--2001
24. Country Assistance Evaluation: Policy, Participation, People (RN 22551) ---2001
25. Private Solutions for Infrastructure: Opportunities for Uganda---2001
26. Inspection Panel Notice of Registration--Power III and Power IV---2001
27. Key Factors for Private Sector Investment in Power Distribution---ESMAP Report #23873---2001
28. Power III and Bujagali --Inspection Panel Report and Recommendation---2001
29. Bujagali Hydropower (P078024) (Same as P063834) and cancelled---2001
30. Energy for Rural Transformation (Plus GEF and Carbon Fund) (P069996, P070222, P072090)--2001
31. Bujagali Private Hydropower Development (P063834, Guarantee B-00-UG)---2001
32. Inspection Panel Investigation Report-Bujagali ---2002
33. Management Response to Investigation Report---2002
34. Power project III and Supplemental Credit—ICR--(Report number 24406)--2002
35. Second Private Sector Competitiveness --2004
35. Second Private Sector Competitive project (Credit Number 3975-UG)--2005
36. Power Sector in Africa: assessing impact on poor people--2005
37. Bujagali Hydro Power -PCN (Report Number 33722-UG)--2005
38. Joint Assistance Strategy (2005-2009)
39. Country Assistance Strategy--Completion Report---2006
40. Uganda Poverty and Vulnerability Assessment—2006

Annex B2—Donors & UEB's Loans-December 2000

Lender	Date	Amount	Currency	US$ Equivalent	Loan Reference
AfDB					
Denmark DANIDA	March '95	111,700,000	DKK	18,232,336	(95)
EIB	December'96	11,000,000	ECU	13,725,748	(UEB-91)
Finland Exportfin	November'97	12,127,287	NOK	1,825,174	(97)
Finland NDF	1990	4,000,000	SDR	5,687,602	(P-II/90)
Finland NDF	August '94	5,000,000	SDR	10,111,352	(1300FE93)
Japan JICA	January '94	1,436 million	Yen	25,144,801	(3Proj-UEB)
Japan JICA	March '95	1,144 million	Yen	11,802,010	(IV-1999)
IDA	March '92	18,620,389		19,014,505	(IDA 15600)
IDA	April '92	66,100,000	SDR	106,422,512	(IDA 22680)
IDA	June '95	24,000,000	SDR	15,152,323	(IDA 22681)
Norway	January '94	116,800,000	NOK	17,312,626	(111CR94)
Norway	January '94	16,500,000	NOK	3,175,775	(CRPower2)
Norway	November'99	48,000,000	NOK	5,493,478	(Kab-Lira-To)
Norway NORAD	June '95	112,000,000	NOK	17,655,972	(UGD-014)
Norway NORAD	June '95	64,000,000	NOK	3,680,863 (??)	(U13)
Norway NORAD	June '95	55,487,975	NOK	3,416, 536	(UGA-023)
UK	June '89	5,660,000	GBP	14,581,410	(UG89-Nasy)
UK ODA	April '92	7,110,847	USD	7,404,750	(P2L/Convr)
UK ODA	November'92	140,090	GBP	613,148	(92-UEB)
UK ODA	March '93	144,094.15	GBP	2,487,849	(93-UEB)
UK ODA	June'93	9,723,000	GBP	24,964,707	(UG93-Nasy)
UK ODA	December'98	346,000	GBP	819,115	(98-Nasy)
Sweden BITS/SIDA	March '95	95,824,000	SEK	17,943,150	(OFE3 AB)
Sweden BITS/SIDA	June '95	69,848,077	SEK	7,417, 113	(15150)
Swiss	March '94	5,000,000	SFR	5,150, 869	(UEB 94)

Annex B3—Components of UEB's Development Program

The following comprises the components of the UEB's development program for 1992 -1996, as provided in the APPRAISAL REPORT.

(1) a canal-fed extension of power generating facilities at the Owen Falls site consisting of three 34 MW units, a double circuit 132 kV transmission line linking it to the rest of the UEB grid; the canal will have a throughput capacity of 4,200 cubic meters of water per second, and with gates at its down-stream will have the capacity to draw-down the lake in the event of heavy rains to ensure that the Owen Falls dam is not overtopped;

(2) the employment by the UEB of consultants and a panel of dam experts to advise on the condition and steps required to strengthen the existing Owen Falls dam;

(3) measures to strengthen the Owen Falls dam;

(4) a structured rehabilitation, by UEB staff, using mainly indigenous poles to replace unsound ones, of the existing 132 kV transmission line from Kampala via Kabulasoke to Masaka, and a supply and erect contract for a new (285 km) 132 kV transmission line from Masaka via Mbarara to the western region including the Hima cement factory, together with substation reinforcements at Masaka, and a new 132 kV/33 kV substation at Mbarara;

(5) institution-building activities including a training workshop and provision of associated training equipment, a 4-year technical assistance link with an established overseas electricity utility to provide training and experience in the areas of operations, financial control, management systems, and modem methods of routine maintenance, and training, other technical assistance and in-house and overseas training for UEB employees;

(6) supply and erect contracts for the rehabilitation of transmission and distribution systems and substations at 132 kV, 33 kV and 11 kV on the UEB grid throughout the country;

(7) support to the Ministry of Energy including interventions in the household energy sector;

(8) rehabilitation of the fabric of two of UEB's buildings—its head-office and the Owen Falls power station;

(9) electrification of selected rural and semi-urban areas resulting from the recommendations of the recently completed National Electrification Planning Study;

(10) an environmental impact review of Uganda's least-cost hydroelectric plan;

(11) an engineering design for the next hydro site to be developed in Uganda's least cost power development plan; and

(12) a study to pre-feasibility level of hydroelectric sites with medium-sized (about 10 MW) capacity.

Annex B4.1—Power III Project Cost Estimate and Financing Plan (1991 US$ Million)*

	Components	Total Cost	IDA	AFDB	ISDB	ODA	BITS	OECF	NORWAY	SIDA	UEB	OTHERS	Total Finance Available	Short Falls
1	Civil Work (including spillway)	165.2	65.2	45	20						15.6		145.8	19.4
2	Dam strength	30.2	27.8								2.4		30.2	0
3	Equip supply construction (gates, guides, etc.)	14.0									0.5		0.5	13.5
4	Turbines and Governors -3X35	22.1							21		1.1		22.1	0
5	Generators and Exciters -3X34	21.5									1.1		1.1	20.4
6	Gen Transformer +Switchgear	1.6								1.6	---		1.6	0
7	132 kv transformer +switchgear	10.1					8.6				1.5		10.1	0
8	Mechanical and Electrical installation contract	12.6									1.4		1.4	11.2
9	Owner costs (housing)	12.0								2.4	9.6		12.0	0
10	Engineering and Supervision	24.0	22.8								1.2		24.0	0
	Total OFE and Dam strengthening	313.3	115.8	45	20	-----	8.6	------	21.	4.0	34.4		248.8	64.5
11	TA support for EB	8.1				8.1					0		8.1	0
12	Next Major Hydro	3.6							3.6		0		3.6	0
13	Power II T&D (33kv and 11 kv) –see footnote "a"	8.0	7.9 (Ref from P.II)								0.1		8.0	0
14	TA to MOE	1.1	0.5			0.6					0		1.1	0
15	PPF repayment	0.8	0.8										0.8	0
	Total Other Components	21.7	9.2	----	----	8.7	----	----	3.6	---	0.1		21.6	0
	Total -Power III	335.0	125.0	45	20	8.7	8.6	--	24.6	4.0	34.5		270.4	64.5

*Includes 12% ($32.4 million) physical and 12% ($36.2 million) price contingencies.

a) This component was to be financed under Power II but due to shortage of funds was shifted to Power III.

Annex B4.2—Summary of Power III and Supplementary Credit Cost Estimate and Financing Plan

(US$ millions)

Components	Power III (1991 estimate)					Suppl. Credit (2000)			Total			
	Total Costs	IDA	GOU	COF	Gap	Total costs	IDA	GOU	Total	IDA	GOU	COF &Gap
Civil works including the spillway	165.2	65.2	15.6	65	19.4	34.2	28.6	5.6	199.4	93.8	21.2	84.4
Dam strengthening	30.2	27.8	2.4						30.2	27.8	2.4	
Turbo-generators and machineries	71.8		4.1	22.6	45.1				71.8		4.1	67.7
Transmission	10.1		1.5	8.6					10.1		1.5	8.6
Owners costs	12		9.6	2.4					12		9.6	2.4
Engineering and Supervision	24	22.8	1.2			0.25	0.25		24.25	23.05	1.2	
Total cost of OFE and dam strengthening	313.3	115.8	34.4	98.6	64.5	34.45	28.85	5.6	347.75	144.65	40	163.1
TA to UEB and MOE	9.2	0.5	0	8.7		0.65	0.65		9.85	1.15		8.7
Next major hydro site	3.6	-	0	3.6					3.6			3.6
PPF	0.8	0.8	0						0.8	0.8		
T&D from Power II	8.1	7.9	0.1		0.1				8.1	7.9	0.1	0.1
TA to MOF	--					3.5	3.5		3.5	3.5		
Total	335	125	34.5	110.9	64.6	38.6	33.0	5.6	373.6	158	40.1	175.5

Source: World Bank

Annex B5—Power Sector Investment Program (1992-1996)—Cost Estimate (1991 US$ million)

A. Owen Falls Extension	Components	Cost	(PR), Program (PM)
1	Civil work including the construction of canal and spillway	165.2	PR
2	Dam strengthening	30.2	PR
3	Equipment supply contract for power station & spillway gates, guides, hoists and superstructure	14.00	PR
4	Turbines and Governors—3X35 MW	22.1	PR
5	Generator and Exciter— 3X34 MW	21.5	PR
6	Generator transformer and switchgear	1.6	PR
7	Transmission and switchgear	10.0	PR
8	Mechanical and electrical installation	12.6	PR
9	Owners costs (housing and facilities)	12.0	PR
10	Engineering/supervision of construction, dam investigation and POE	24.0	PR
	Total Owens Falls	313.2	
B. Other Components			
1	132 kv Western transmission line, substation and rehabilitation	33.3	PM
2	132 kv Western transmission line, engineering and supervision	2.1	PM
3	Technical assistance to UEB	8.1	PR
4	Transmission and distribution -132 kv substation	1.9	PM
5	Transmission and distribution—33 and 11 kv substation	24.3	PM
6	Transmission and Distribution-Pole treating plant	1.9	PM
7	Transmission and distribution-distribution materials, erection costs, telecom and vehicle	38.28	PM
8	Transmission and distribution- engineering and supervision	2.7	PM
9	Rehabilitation if the fabric of OFE's HQ	4.8	PM
10	Rural electrification	11	PM
11	Next major hydro site feasibility study	3.6	PR
12	Pre-feasibility study of medium range hydro site	1.8	PM
13	Sector environmental review	1.1	PM
14	Support to Ministry of Energy	1.1	PR
15	PPF's repayment	0.8	PR
	Total Costs of	326.8	
	Total non- cost	123.2	
	Total costs of Program	450.0	

Annex B6—Monitoring Guidelines (from SAR)

Description	1989	1990	1991	1992	1993	1994	1995
	Actual	Estimate	<-------------Proposed Targets------>				
Technical							
Installed Dependable capacity (MW)	112	123	133	145	152	159	232
System Demand							
Uganda (GWh)	503	541	580	621	660	700	744
Kenya (GWh)	157	200	200	200	200	200	236
Total (GWh)	660	741	780	821	860	900	980
(MW)	112	122	127	133	142	151	164
System Losses:							
Non-Technical (%)	25	21	16	13	9	7	7
Non-Technical (GWh)	126	114	93	81	59	49	52
Technical (%)	19	19	19	17	16	15	14
Technical (GWh)	96	103	110	106	106	105	104
Total (%)	44	40	35	30	25	22	21
Total (GWh)	221	216	203	186	165	154	156
Billed sales (GWh) 1/	279	314	354	397	442	478	504
Institutional							
No. of un-registered domestic and commercial users	33,000	25,000	15,000	10,000	7,000	4,000	1,000
No. of registered Domestic and commercial users	94,074	102,074	112,074	116,928	122,274	128,038	134,240
Industrial	10	12	14	17	21	25	30
General	803	851	902	956	1,014	1,075	1,139
Hotels and clubs	829	854	879	906	933	961	990
Street lighting	95	96	97	98	99	100	101
Total number of connections	128,811	128,967	128,887	128,905	131,340	134,198	137,499
Billed sales/consumer (kWh)	2,166	2,436	2,745	3,080	3,365	3,562	3,665
No. of employees	2,100	2,188	2,188	2,338	2,500	2,550	2,600
No. of consumers	95,811	103,887	113,967	118,905	124,340	130,198	136,499
No. of consumers/employee	46	47	52	51	50	51	52
Billed sales/employee (MWh)	133	144	162	170	177	187	194
Financial							
Operating Ratio (%)	99	60	102	63	48	43	40
Rate of Return (%)	2	2	-	4	7	10	7
Current Ratio (times)	4.1	1.7	8.4	19.9	37.4	50.4	58.0
Debt/Equity Ratio	94/6	18/82	19/81	34/66	43/57	48/52	51/49
Debt Service Coverage (times)	0.04	0.1	1.1	1.2	1.5	1.5	1.1
Net Internal Cash Generation as a percentage of new investment (%)	12.6	8.9	10.1	10.4	16.5	21	29.7
Accounts receivable as % of sales	48%	52%	26%	25%	25%	25%	25%
Accounts receivable in months of sales	5.8	6.3	3.1	3	3	3	3

1/ Uganda sales assuming low growth.

Annex B7—World Bank Statement on Lake Victoria Water Level

March 16, 2006—The World Bank is concerned about the decrease in Lake Victoria's water level. This is a very complex situation, given the environmental, social and economic importance of Lake Victoria, the prolonged period of regional drought, and significant hydropower shortfalls throughout the region.

Recent reports, including a report of the East African Community (EAC) Regional Technical Working Group in January 2006, as well as Bank analysis of available data, attribute the falling water levels to the extended 3-year period of drought in the region and over abstraction of water for power generation. The Bank continues to work with partner states on improving water management, and addressing the prevailing power shortages as a matter of urgency.

Water management: Through the regional Lake Victoria Environmental Management Project (LVEMP) and the Nile Basin Initiative, the Bank is supporting improved environmental management of the Lake Victoria and the Nile basin. Specifically, LVEMP has assisted the countries to:

- better measure stocks of fish
- reduce infestation of water hyacinth to manageable levels through biological and other controls
- understand issues of hydrology of the lake and water quality
- react appropriately to a temporary ban on exports of fish imposed by the EU
- improve the livelihoods of selected lakeside communities through micro-investments,
- lay the foundation for enhanced regional management of the lake through establishment of the Lake Victoria Basin Commission.

Partner states— Uganda, Tanzania and Kenya— continue to monitor the Lake levels and are implementing short term measures recommended by water experts. On World Bank advice, these countries commissioned a situational analysis of Lake Victoria and its catchment hydrology and meteorological regimes, which was discussed by a technical working group in January 2006. Heads of State will come together on April 5 to discuss this critical issue. The World Bank will continue to provide technical support to this process. Affected countries are also looking to establish regional mechanisms for more effective water management, expected to be supported by a second phase of the Lake Victoria Environmental Management Project. In addition, there are World Bank projects under preparation that will contribute to better water management in upper catchments close to the Lake, thereby benefiting the Lake indirectly.

Power: The World Bank has proposed to assist countries for the loss of hydro-power, by installation of thermal and gas as well as accelerating regional interconnectivity. The quickest wins will come from improving overall efficiency and performance, followed by environmentally sustainable investments in least-cost generation and related transmission and distribution. In parallel, the World Bank is helping countries meet the energy needs of unserved rural populations.

To respond to the prevailing energy situation in the region, the Bank and other partners are discussing a number of options with the affected Governments, including:

- procurement of short-term generation capacity;
- instituting measures for accelerated efficiency in electricity transmission and distribution, with the objective of reducing power losses; and
- the development of longer term, least-cost power generation.

Annex B8—Actual Bank Disbursement per Category (Original US$ Million)

Description	Category	Disbursed (22680)	Disbursed (22681)	Total Disbursed
Civil Work	1-A	4,455,397.31	19,509,414.49	85,560,529.07
	1-B	61,595,717.27		
Equip & Machin & Dam Safety	2	21,269,535.23	None	21,269,535.23
Consulting Services	3	27,451,741.76	938,154.16	28,389,895.92
Tech Assistance	4	1,910,696.34	None	8,921,294.65
	4-A	1, 435,633.87	None	
	4-B	2,279,085.05	None	
	4-B-II	None	3,295,879.39	
PPF	5	750,986.97	None	750,986.97
Misc.	SAA	5,133.26	None	5133.26
Total		121,153,927.10	23,743,448.04	144,897,375.14

1=Civil work 100% F/10
1--A=Civil Works-Advance Payments
1--B=Civil Works-Others
2= Electrical and Mechanical Equipment
3=Consulting Services
4=Technical Assistance
4--A= Technical Assistance-UEB
4--B=Technical Assistance—MNR/MOE
4--B--II=Technical Assistance
5= Refunding PPF
SAA= Miscellaneous/Residual in Special Account

Annex B9—Actual Bank Disbursement per Beneficiary for Power III and Supplementary Credit

Contractor	Cate gory	Type of Contract	Amount US$-22680	Amount US$-22681	Total Amount US$
Greland Bank	1-B		1,905, 582.06		
Impregilo/Salini	1-B	Civil work-OFE 101	54,466,088.06		
Impregilo/Salini	1	Civil work-OFE 101		12,116,438.73	
Interfreight Corp	1-B		388,388.94		
Not Identified	1-A		3,556,179.71		
Not Identified	1-B		302,227.27		
IP Machinery	1-B		200,584.21		
SAA	1-A		899,217.60		
SAA	1-B		4,280,690.24		
Shell Uganda	1-B		52,156.49		
Stirling/Rodio	1	Dam remedy-OFE-56		7,363,683.87	
Tungabhadra	1	Gates, etc.OFE-5		29,291.81	
Total in Category 1			66,051,114.58	19,509,414.41	85,560,528.99
GTA & SAD	2		1,006,233.69		
Mowlin Interna	2	Draft Tube, etc. OFE-12	499,128.48		
Not Identified	2		10,121,121.65		
SAA	2		6,420,723.58		
Spec Comm 2	2	Citi Bank (BEF)	158,291.42		
Spec Comm 2	2	Banque Indosuez (BEF)OF-10	441,213.85		
Spec Comm 3	2	Citi Bank (GBP)	265,092.82		
Tungabhadra	2		2,357,729.74		
Total in Category 2			21,269,535.23	None	21,269,535.23
Acres International	3		7,673,679.57		
Acres International	3			552,843.33	
Alexander Gibb	3	Dam Remedy-OFE-56		385,310.83	
Huntington Williams	3		514,910.97		
Not Identified	3		6,495,204.95		
SAA	3		12,767,946.27		
Total in Category 3			27,451,741.76	938,154.16	28,389,895.92
Fielldstone Africa	4B-II	UEB Privatization		140,000	
Hagler Baily	4B-II			513,123.62	
Hubtington Williams	4-B	Legal Advisory	1,497,869.49		
Not Identified	4		844,399.25		

Contractor	Category	Type of Contract	Amount US$-22680	Amount US$-22681	Total Amount US$
(SAA)					
Not Identified	4-A		168,865.50		
Not Identified	4-B		514,910.97		
PA Government	4B-II	UEB privatization		2,642,755.77	
SAA	4		1,066,297.09		
SAA	4-A		1,266,768.37		
SAA	4-B		266,304.59		
Total in Category 4			5,625,415.26	3,295,879.39	8,921,294.65
Refund of PPF	5	Refund PPF	750,986.97	-----	750, 986.97
Total in Category 5			750,986.97		
SAA	SAA		-43,140.79		
SAA	SAA		48,274.05		
Total in SAA			5,133.26		5133.26
Total			121,153,927.20	23,743,447.96	144,897,375.2

Annex B10—Performance of Equipment installed under Power III

1st -September-2006

Background

Installations at Kiira Power station constitutes the major equipment installed under power III. It includes Generating sets of Units 11 and 12, all civil works, the water control equipment Gantry cranes and the power house crane. Also included is the switch gear, the overhead power transmission line and the booms; Trash booms, safety booms and the water Hyacinth booms at the source of the Nile. All this equipment was commissioned by year August 2000. This report the effectiveness of performance of this equipments and highlights only defects which are regarded as major and or reported during guarantee period. The report describes the performance of equipment in the order in which the equipment was commissioned.

Gantry Cranes

The gantry cranes were almost the first to be commissioned. The first failure was reported on the powerhouse crane when it failed to lift turbine equipment during first date of installation. The problem was identified as defective control system and was solved by replacement of the complete electrical controls. Both intake and tail race gantry crane operations have been characterized with multiple failures. One cannot be sure of their continuous operation during any one activity. Below are major defects registered on each of this equipment;

- **Intake gantry crane**

This crane derailed late in 2002 due to a strong storm. Its frame was deformed and was repaired. Frequent trip of the control circuit during operation, no loss of any component has been experienced as yet.

- **Tail race gantry crane**

Loss of winding of the two traverse travel electric motors was registered in November 2004. The motor winding burnt due to malfunction/ingress of water and moisture.

- **Power house crane**

Only failure of the gear box seal was recorded and breakage of the 2 Ton wire rope have been recorded.

- **Mechanical services**

These are equipment installed to facilitate proper station drainage, ventilation, compressed air and water supply, sanitation and fire fighting. The performance is good apart from defects indicated.

- **Dewatering and drainage system**

Failure of the station pump was registered in 2000. The pump was replaced with a spare one and the failed one had its winding rewound locally. Dewatering pump one has had failure of the shaft by shear twice in both case the shaft was renewed. The microprocessor of the complete dewatering mode also failed last quarter of 2004.

Generator Transformer
All are running at relatively high temperatures. One of the disc insulations on Unit 11, Blue Phase on 132KV side was shuttered in August 2005.

The turbine
The turbine operation is good. The turbine consists of the Governor system, Wicket gate apparatus, the runner and the imbedded parts. The following defects have been registered on the turbine.

- **Runner**

Loss of protective paint coating on the turbine parts and wicket apparatus was observed on both Unit 11 and 12 in 2002 during guarantee inspection.
Extensive damage of the lower turbine cover due to cavitation observed during inspection of Unit 12 in August 2006..

- **Shaft seal cooling system**

The shaft seal pump couplings have registered failure and have been replaced twice.

The generator
The generator is composed of the stator winding, the rotor, 11 KV switch gear, the excitation equipment and all the associated protection and Control equipment.

The VIMOS
The VIMOS equipment (vibration monitoring) on Unit 12 is completely failed.

- **Excitation equipment**

The field switches of both Units 11 and 12 are under rated and failure of the copper bars has been recorded. Failure of the Transducers is being experienced to date.

The 11 KV circuit breaker of Unit 12 exploded in November 2005.

Water control equipment
Water control equipment consists of all the spillway gates, stop logs, emergency control gates and trash racks. Major problems have been encountered especially with the gate controls. The workmanship was poor, the components look old and all control panels are not water proof. Specific defect are highlighted below.

- **Emergency control gates**

Multiple failures of the electrical components have been experienced. The Main a/c supply contacts have burnt twice on Unit 12. Both Unit 11 and 12 each have lost each a brake clutch due to burning. The hoist rope on Unit 12 passage 4 rolled over the drum in November 2004.

- **Spillway gates**

One contactor was lost during its operation.
Generally all the gates have lost the protective paint.

- **Booms**

The booms consist of trash booms, safety booms and water Hyacinth booms at the source of the Nile. The performance has not been reliable especially for the water Hyacinth booms. Specific defects recorded are indicated below;

- **Trash booms**

Failure of the boom clamps was registered. The wire rope is rusty shall require replacement.

- **Safety booms**

Has broken three times. The boom link fatteners are necked and rusted, resulting into joint failure due to bolt shear.

- **Water hyacinth booms**

Completely failed. All the booms have broken off at some stage or the other. The wire rope is broken. All the wire rope is rusty and has hardly worked for 5 years.

Failure of equipment due to normal aging or lack of maintenance is expected, however the equipment which was supplied under OFE 5, has exhibited failure right from the commissioning stage. It now appears normal to operated in this "ABNORMAL" operation. The steel wire ropes for both trash and water Hyacinth booms are of inferior quality, in 5 years time of operation they are all rusty. In fact the one for water Hyacinth booms is broken and they are all due for replacement.

Annex B11—Supervision Missions

Mission	Mission Date	MG LTR Date	BTOR Date	Current 590	Last 590	DO Now/Last	IP Now/Last
Supervise Power III, ICR, PLUS	September 7-20, 2001	November 8, 2001		November 21, 2001		S&S	S&S
Supervision Power III	May 21-25, 2001	June 25, 2001	June 25, 2001	June 29, 2001		S&S	S&S
Supervision PUSRP	Oct. 27-Nov 4, 2000		Nov 16, 2000				
Supervision Power III	Oct. 10-20, 2000	Nov 15, 2000	December 29, 2000	March 13, 2001 (6/29 & 12/13 w/o)			
Supervision Power III	March 13-24, 2000	May 4, 2000					
Supervision Power III	Nov 10-Nov 16, 1999	Dec 15, 1999	Dec 1, 1999	Dec 14, 1999		S &U	S&S
Supervision Power III	May31-June11, 1999	July 26, 1999	June21, 1999	June 30,1999	May 14,1999	U&U	S&S
Supervision Power III	March 16, 1999			May 14,1999	Feb 16, 1999	U&U	S&S
Supervision POE	Nov 7-13,1998						
Supervision POE	June1-5, 1998		June25, 1998	June30, 1998	Jan 29, 1998	S&S	S&S
Letter by Jim Adams	May 2, 1998						
Supervision OPE	Feb 8-14, 1998		March12, 1998				
Supervision Power III	Nov 15-26, 1997	January 9, 1998	January 14, 1998	Dec 24 1997	July 7, 1997	S&U	S&U
Supervision Power III	June1-13, 1997	June23, 1997	June30, 1997	June26, 1997	Oct 18, 1996	U&U	U&U
Supervision Power III	Feb 3-19, 1997	March 11, 1997	March 27, 1997				
Supervision Power III	Nov 19-Dec1, 1996	Dec 30, 1996	January 31, 1997				
Supervision Power III	August 11-25, 1996		October 23, 1996	Oct 18, 1996	April 25, '96	U&U	U&U
Supervision Power III	June 8-12 1996						
Supervision POE	March 24-31, 1996		May22, 1996	April 25, 1996	July20, 1995	U&S	U&S

Mission	Mission Date	MG LTR Date	BTOR Date	Current 590	Last 590	DO Now/Last	IP Now/Last
Supervision Power III	Feb3-11, 1996	March 21, 1996	March 21, 1996				
Supervision POE #6	Dec 111-14, 1995		December 15, 1995				
Supervision POE	August 6-14, 1995	September 7, 1995	September 7, 1995				
Supervision Power III	May 7-21, 1995		July 13, 1995	July 20, 1995	June29, 1995	S&S	S$S
Supervision POE	Jan 17-21, 1995		Feb 13, 1995				
Supervision Power III	Oct 29, Nov 9, 1994	January 4, 1995	Dec 29, 1994	Dec 15, 1994 (6/29 & 7/20 w/o)	Sept 26, 1994	S & S	S & S
Supervision Uganda	March 7-11, 1994		March 28				
Supervision Power III	Feb 21-March 11, 1994	April 22, 1994	March 31, 1994	March 31, 1994	December 14, 1993	1 & 1	Overall:2&2
Supervision Power III	Oct 30-Nov 7, 1993		December 20, 1993	Dec 14, 1993	September 10, 1993	1 & 1	Overall:2&2
Supervision Power III	April 17, -22, 1993		June4, 1993	June7, 1993 (9/10 w/o)	December 21, 1992	1 & 1	Overall:2&2
Supervision Power III	Nov 7-15, 1992		December 18, 1992	Dec 21, 1992	September 03, 1992	2&1	Overall:2&2
Supervision Power III	April 30-May 10, 1992		June 2, 1992	June 09, 1992 (8/27 &9/03 w/o)	None	1	Overall : 2
Supervision Power III	Sept 1-9, 1991		Sept 23, 1991	Sept 18, 1991	August 29. 1991	2&1	NR

Annex C — Borrower Comments

TELEGRAMS: ENERMIN
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IN ANY CORRESPONDENCE ON
THIS SUBJECT PLEASE QUOTE NO
ESD/141/228/01

THE REPUBLIC OF UGANDA

MINISTRY OF ENERGY AND
MINERAL DEVELOPMENT
P. O. BOX 7270,
KAMPALA.

June 13, 2008

Mr. Fernando Manibog
Sector, Thematic and Global Evaluation Division
The World Bank
1818H Street N.W.
Washington D.C. 20433
USA

Dear Mr. Manibog,

RE: UGANDA - THIRD POWER PROJECT (CREDIT NO. 22680 - UG) AND SUPPLEMENTAL TO THIRD POWER PROJECT (CREDIT NO. 22681 - UG): DRAFT PROJECT PERFORMANCE ASSESSMENT REPORT

1. Please refer to your letter dated March 7, 2008 on the above subject. Unfortunately, we received this letter late hence the late submission of our comments. By copy of this letter to the Executive Director for Uganda, we request her to bring up the issues raised herein during the discussion of the Project Performance Assessment Report (PPAR) by the Bank's Board. The following are our comments on the PPAR for Uganda's Power III project and its Supplementary Credit:

General Comment

2. The PPAR gives a fair account of the Power III project preparation and implementation. However, there are a number of areas in the report which we feel require better treatment to enhance the value of this report. Those areas are outlined below.

Uganda's Energy Resources

3. The report states in para1.7 that "Uganda is poorly endowed with energy resources...." It continues to state that "the country has no oil, gas...."Our view is that this is a misrepresentation of known facts. First of all, if the Victoria Nile hydropower potential is effectively harnessed it can make a significant contribution to the country's modern energy needs. Secondly, the country has numerous small hydropower sites (with aggregate capacity of over 200 MW) which have not been developed and if developed can have a significant impact on the provision of modern energy services to rural communities through decentralised grid systems.

4. The country has enormous biomass resources, currently contributing about 92% of the country's energy supply. The importance of biomass as an energy resource needs not be over emphasised. It provides energy for cooking and heating for the majority of the population at minimal cost to them. It is also a source of energy for a host of small and medium scale enterprises. There are efforts to utilise biomass for power generation using various technologies including gasification. For this resource, there are two major issues to consider, namely: (i) ensuring regeneration of biomass stock through deliberate reforestation programmes; and (ii) improving the efficiency of the biomass end use technologies and elimination of indoor air pollution. We have ongoing programmes in the ministry (and there are a number of private actors) to address the latter.

5. Another resource is solar energy. The solar photovoltaic and solar thermal resources are virtually untapped yet the country has sunshine throughout the year. Average solar radiation is 5.1 kWh/ m^2 per day. The country also has substantial peat resources, sufficient to produce 800 MW of electricity for 50 years, which are yet to be tapped. Wind energy in some locations can be utilised for water pumping and electricity generation is possible in some areas where wind speeds are appreciably high. Regarding the geothermal resource, feasibility studies are being carried out in the western rift valley.

6. In the area of oil and gas, commercial oil discoveries have been registered in Uganda. Government is currently working with one of the oil companies to utilise the locally produced oil to generate 50 - 100 MW of power by 2010, to alleviate part of the current power supply deficit, and increase the energy mix to mitigate against issues of climate change.

7. Government strategy is also to implement energy efficiency and demand side management measures to ensure rational use of energy. A recent distribution of energy saver bulbs resulted into a reduction of close to 30 MW, on the peak demand. The above clearly demonstrates the huge energy potential, virtually untapped, which the country enjoys. Since the report is meant to be a public document, this major anomaly regarding Uganda's energy potential needs to be corrected.

The Decline of Lake Victoria Water Level

8. The general trend is such that the Lake Victoria water level has been on a steady decline, ever since the dramatic rise in the early 1960s. However, the PPAR tends to create a misleading impression that the drop in lake level experienced during the period 2003 – 2006 is a clear manifestation that Lake Victoria has retuned to the low hydrology of the 1900 – 1960 period.

9. We have not come across authoritative literature or hydrology which with a high degree of certainly predicts what the hydrology of Lake Victoria will be in the next 30 or 40 years. What we know is that the east African region experienced protracted drought conditions during the period 2003 – 2006. Lake Victoria was not the only lake affected by the drought but also the other lakes in the region. Hydropower resources in neighbouring countries of Tanzania and Rwanda and Kenya were similarly affected. At one stage, for example, the hydropower facilities of Mtera and Kidatu in Tanzania had to be closed. Following the rains of end of 2006 and early 2007, these facilities, with a combined capacity of 280 MW are now producing at full capacity. The limitation we have in Uganda is the need to adhere to the Agreed Curve. It is ironical that with the largest lake in Africa behind the Kiira and Nalubaale facilities, we can only generate about 140 MW at the current lake level.

10. Over the years, variations in Lake Victoria water levels have been observed. For example in October 1997, the lake was at an average level of 11.32 meters at the Jinja gauge. Seven months later, in May 1998, the level had raised to 12.88 meters, following El Nino rains, a rise of some 1.5 meters Furthermore, the lake is currently recovering, though at a slow pace as the rains have not been very good, from the low level of 10.40 meters in October 2006 to the current level of about 11.40 meters. What this signifies is that it would be erroneous to assume that the lake level will remain very low, say to

the next 50 years, thus rendering Kiira Power Station a useless asset (as alluded to under para 4.22).

The Value of Kiira Power Station

11. The report implicitly questions the rationale for the Kiira Power Station project (para 4.17) since at the time of the assessment mission, only 120 MW was being generated from both Nalubaalc and Kira Power Stat ons, which capacity could well be generated by the original 10 units at Na ubaale Power Station.

12. It will certainly continue to be debated by those familiar with Uganda' s power sector, whether or not Kiira Power Station was meant to add 200 MW to raise the hydropower capacity at the Owen Falls site to 380 MW (180 MW (Nalubaale) + 200MW (Kiira)). What is clear though is that between 1971 (when the last unit was commissioned at Nalubaale Power Station) and 1999 the water outflow down the Victoria Nile at Jinja constituted two segments, one segment going through the 10 generating units at Nalubaale and the other going through the sluices to make up the quantum specified by the Agreed Curve. Analysis of the outflows during that period reveals that those segments were in the proportions of 52% and 48% of the total outflow, respectively.

13. Acre's original design of an extension of 102 MW was specifically targeting the outflows which had been 'wastefully' let down the sluices over the 30 year period. This would yield at a total installed capacity of 282MW for the Owen Falls site.

14 The main consideration to increase the capacity of Kiira Power Station from 102 MW (3 x 34 MW) to 200 MW (5 x 40 MW) was the physical condition of the Nlubaale Power Station. The Hydropower Development Master Plan Report of 1997 (Kennedy and Donkin) put the life of the rehabilitated Nalubaale Power Station at some 25 years. The power station has huge cracks and the movement of the concrete affects the alignment of the shafts. Kiira Power Station is therefore a new installation meant to replace the ageing Nalubaale Power Station. It is meant to be operated as a base load plant with operational units in Nalubaale Power Station used to provide peaking power.

System Losses

15. The issue of system losses, standing at some 40% (both transmission and distribution losses), poses a major challenge for the power sector especially at this time when expensive thermal power constitutes nearly half of the total generation. Umeme has formulated a strategy to address system losses and will be working closely with Government in this endeavour. Although the PPAR suggests that tackling system losses should take precedence over further capacity expansion (para 4.2) our view is that the issue of capacity expansion is equally important and the two should be handled simultaneously. It should be noted that losses cannot be eliminated at once. We are therefore looking short term and medium term measures of tackling this problem.

Institutional Roles and Capacity

16. Para 5.2 states that, "Uganda's power sector is in dismal state and the options available to it over the next 15 to 20 years are mostly unattractive". This is a very pessimistic view and a misrepresentation of what is happening on the ground. The sector has certainly had its fair share of challenges especially the prevailing power crisis. Those of us who are on the ground are confident that the worst is behind us. A number of generation projects are at different stages of development. Key among these is the Bujagali project with which we are all familiar. A 50 MW thermal power plant based on heavy fuel oil is due for commissioning at the end of October 2008 and will replace one of Aggreko's diesel thermal power plants. Another 50 MW plant to be built in Kaiso Tonya and utilise locally produced oil is slated to be commissioned in 2010.

17. Regarding the small renewable energy projects, already one of the sugar mills, Kakira Sugar Works Limited is selling 12 MW to the grid after completing the expansion of its co-generation plant. Two other sugar mills are also preparing expansion of their cogeneration plants. Construction of small hydropower plants with aggregate capacity of about 40 MW, is underway. All these are being developed by the private sector, having overcome the inertia experienced during the early days of private participation. Discussions for the development of Karuma Hydropower Project as a public-private –partnership venture, with the Norwegian company Norpak Power Limited, are at an advanced stage. Government intends to have a substantial stake in the development of this site.

18. Following the reforms in the power sector, different institutions have assumed specific roles. The Electricity Regulatory Authority (ERA) performs the regulatory, tariff setting and standards enforcement roles. Over time, ERA has built its capacity and has since gained confidence in performing its mandate. Uganda Electricity Distribution Company Limited (UEDCL) and Uganda Electricity Generation Company Limited (UEGCL) supervise the distribution concession and generation concession respectively. The Ministry of Energy and Mineral Development is responsible for sector policies and overall sector oversight. Certainly capacity enhancement is essential in all the institutions. It would be misleading, however, to assume that the sector is in disarray as a result of the reforms.

Conclusion

19. In a nutshell, to us there is a glimmer of hope over the horizon for Uganda's power sector. In conclusion, it is our considered view that the PPAR requires more research and enrichment in the areas highlighted above. In its present form, the report serves only a limited purpose to Uganda's power sector.

Yours sincerely,

F. A. Kabagambe – Kaliisa
PERMANENT SECRETARY

CC Ms. M. Ketsela, Executive Director for Uganda. World Bank

The Permanent Secretary/ Secretary to the Treasury
Ministry of Finance, Planning and Economic Development

Mr. Soniya Carvalho
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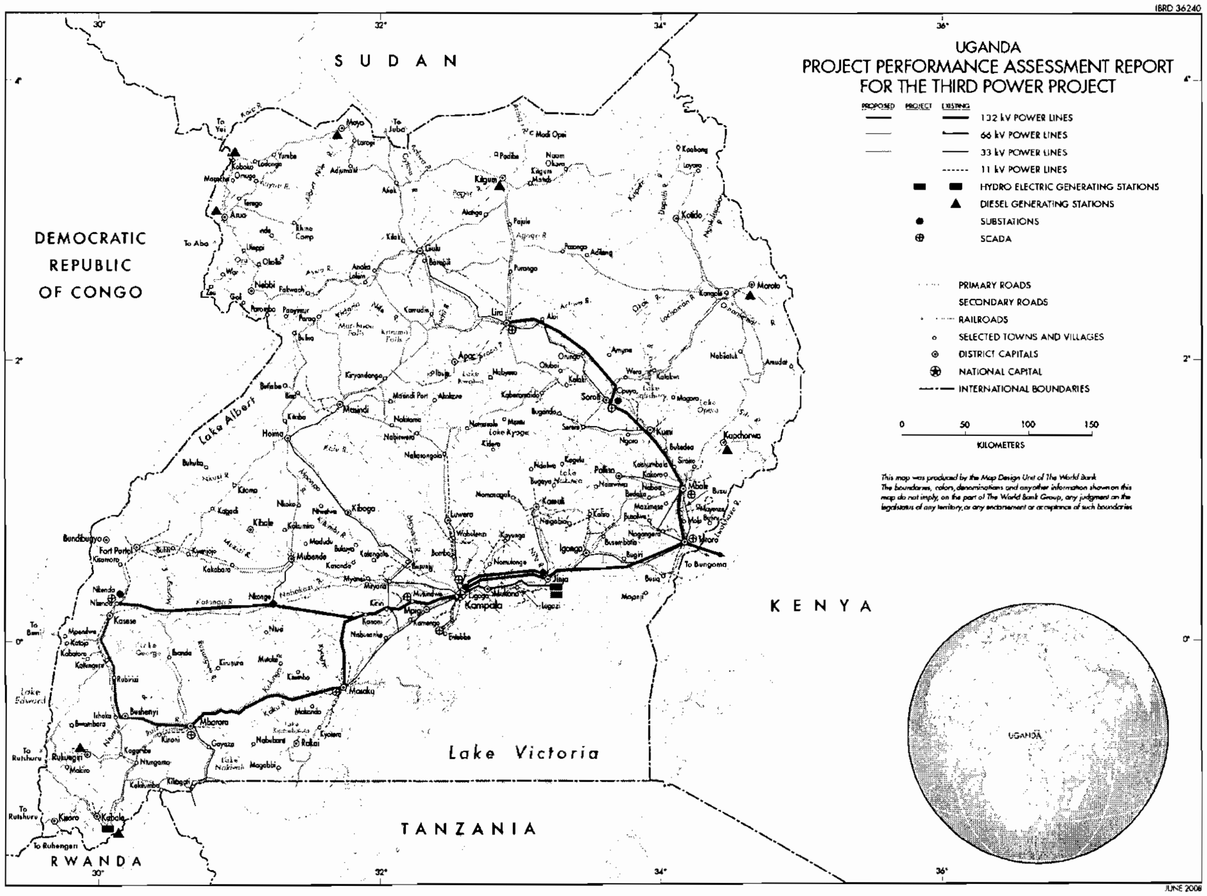
Annex D — Map


IBRD 36240
UGANDA
PROJECT PERFORMANCE ASSESSMENT REPORT
FOR THE THIRD POWER PROJECT
PROPOSED
PROJECT
EXISTING
132 kV POWER LINES
66 kV POWER LINES
33 kV POWER LINES
11 kV POWER LINES
HYDRO ELECTRIC GENERATING STATIONS
DIESEL GENERATING STATIONS
SUBSTATIONS
SCADA
PRIMARY ROADS
SECONDARY ROADS
RAILROADS
SELECTED TOWNS AND VILLAGES
DISTRICT CAPITALS
NATIONAL CAPITAL
INTERNATIONAL BOUNDARIES
0 50 100 150
KILOMETERS
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DEMOCRATIC
REPUBLIC
OF CONGO
KENYA
TANZANIA
RWANDA
Lake Victoria
Lake Albert
Kampala
Lira
Soroti
Mbale
Tororo
Jinja
Masaka
Mbarara
Kasese
Hoima
Masindi
Gulu
Kabale
UGANDA
JUNE 2008