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Review of Tariff Application

Commissioned by
Electricity Regulatory Authority of Uganda and the
Norwegian Water Resources and Energy Directorate

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Executive Summary

Abstract

We have reviewed the price application made by the Ugandan Electricity Board to the Electricity Regulatory Authority of Uganda. We have proposed various changes to the methodology adopted, and implemented these changes to arrive at revised price schedules.

Background

The Electricity Regulatory Authority (ERA) of Uganda was established in 2000 with the function of regulating the electricity industry in Uganda. Under new legislation, the Ugandan Electricity Board (UEB) is obliged to apply for tariff approval to ERA. Since UEB is in the process of being restructured into separate companies (Generation, Transmission, Distribution and a Holding Company), UEB is required to apply for prices for each of these separate companies. UEB submitted its price application to ERA on 8 February 2001.

ECON has been appointed to support the ERA by reviewing UEB's tariff application for 2001. Prices are required to be cost reflective, thereby ensuring adequate revenue to support the operations of the company, and providing appropriate price signals to consumers.

The appointment is funded through the Norwegian Water Resources and Energy Directorate's (NVE) programme of support to the ERA.

Pricing methodology

With regard to generation pricing, we recommend that ERA should provisionally accept the proposed method, and review its practicality over the course of 2001. Should its implementation prove difficult, ERA should seek to design a new pricing approach from 2002 onwards.

With regard to pricing of bulk supply to distribution, we recommend that ERA should accept the proposed approach for 2001, but seek to design an alternative during 2001 that smoothes in the introduction of higher costs associated with the Bujagali power station.

With regard to distribution pricing, we recommend that the cross-subsidies from Codes 30 and 20 to other codes be removed. This report presents prices calculated without this cross-subsidy.

ERA will be able to improve the cost-reflectiveness of distribution prices with better load profile data and improved cost allocation approaches.

Price schedules

We summarise below the price schedules based on an exchange rate of 1800 Ushs/US\$. In arriving at these schedules, we have implemented the following alterations to the tariff model:

- The allocation of interest expenses has been revised
- The allowance for non-technical losses has been reduced by 2 per cent so that total distribution losses are 33 per cent
- The cost allocation method in devising distribution prices has been revised to remove cross-subsidies from customers paying a maximum demand surcharge.

Table A Capacity price charged by Genco to Transco, based on a maximum available capacity of 242 MW

Maximum available capacity 242 MW	Capacity price 26,700 Ushs/MW
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Table B Bulk supply tariffs (Ushs/kWh), based on expected demand

	Peak	Shoulder	Off-peak
Time period	18:00 – 23:00	05:00 – 18:00	23:00 – 05:00
2001	70.1	58.4	43.3
2002	72.2	60.2	44.6

Table C Tariff schedule for end-user tariffs

Tariff code	Power supply charge Ushs/kWh	Fixed monthly fee Ushs/mth	Maximum demand charge 1 Ushs/kVA	Maximum demand charge 2 Ushs/kVA	Energy charge Ushs/kWh	Effective average tariff Ushs/kWh
Code 10	103.6	1 000	N/a	N/a	76.2	183.8
Code 20	103.6	10 000	5 000	N/a	58.0	174.9
Code 22	72.5				17.1	
Code 30	68.9	15 000	3 300	3 000	25.5	82.5
Code 32	47.7				10.6	
Code 50	99.4	4 000	N/a	N/a	67.0	170.3
Code 60		15 000	3 000	3 000		82.5
Peak	77.2				28.6	
Shoulder	64.4				23.8	
Off-peak	47.7				10.6	

Updating of price schedules

The pricing methodology allows for prices to be updated on a periodic basis to reflect changes in exchange rates and actual costs of power purchases by Transco. We recommend that this updating be undertaken on a quarterly basis, i.e. every three months.

ECON has developed a spreadsheet model that allows ERA to implement these price adjustments. We recommend that ERA assume responsibility for managing this process, setting up appropriate information exchange routines to enable it to do so.

In order to undertake the updating process, ERA should collate the following data on a quarterly basis:

Table D Data required for tariff updating

Data from the preceding three month period	Units	Source
The Maximum Available Capacity	MW	Genco
The average exchange rate	Ushs/US\$	Bank of Uganda
The power purchase costs of Transco	Ushs	Transco
The amount billed by Transco to Disco	Ushs	Transco
The volume of energy purchased by Transco	GWh	Transco
The volume of energy exported by Transco	GWh	Transco

It should be noted that the average exchange rate of January and February 2001 is 1780 Ushs/US\$ - slightly lower than the rate of 1800 used in these calculations. Hence, the tariff to be adopted from 1 April 2001 may be slightly lower than the prices presented here.

We recommend that on 2 April 2001 the spreadsheet model be used to determine the prices from that date onwards, making use of exchange rates from 1 January to 30 March 2001.

ERA Board resolutions

Following the submission of the draft report, the ERA Board discussed the recommendations contained herein and passed resolutions dealing with the recommendations made here (see Annex O). The only exception relates to the issue of a lifeline tariff, where the ERA resolved to retain the lifeline for Code 10 customers, and add a lifeline surcharge to other customers in order to pay for the cost of the lifeline. The lifeline was set at 50 Ush/kWh for the first 30 kWh consumed per month, and the surcharge added to other customers was 10 Ush/kWh.

1 Introduction

The Electricity Regulatory Authority (ERA) of Uganda was established in 2000 with the function of regulating the electricity industry in Uganda. Under new legislation, the Ugandan Electricity Board (UEB) is obliged to apply for tariff approval to ERA. Since UEB is in the process of being restructured into separate companies (Generation, Transmission, Distribution and a Holding Company), UEB is required to apply for prices for each of these separate companies. UEB submitted its price application to ERA on 8 February 2001.

ECON has been appointed to support the ERA through this process by reviewing UEB's tariff application for 2001. The appointment is funded through the Norwegian Water Resources and Energy Directorate's (NVE) programme of support to the ERA.

This report presents our findings and recommendations arising from the review.

Documentation submitted

The price application was submitted on 8 February in the following format:

- A covering letter
- A set of Excel spreadsheets containing the tariff model

The covering letter is attached in Annex D. Following correspondence from ERA (see Annex G), UEB submitted further documentation (see Annex K). In addition, further information was submitted in response to ECON queries for more information (see Annex K).

The level of documentation submitted should be considered by ERA inadequate for a price application. In particular, the following are noted:

- There is no documentation of the costs of supply other than information in the tariff model;
- There is no specification of assets and breakdown of asset values; and no information on depreciation calculations or loan obligations;
- The methodology for the allocation of distribution costs to customer categories is not documented;
- There is no documentation of load information used to structure distribution and bulk supply tariffs;
- There is no justification of the allocation of costs to MV and LV levels; and

- There is no justification for the 120 per cent factor used to determine prices during the peak period.

However, given the urgency of the price review process, and the limited capability at UEB to provide such documentation, we recommend that ERA accept the documentation as provided, without setting this as a precedent for future applications.

Future standards for documentation

During the course of 2001, ERA should seek to establish an appropriate minimum set of documentation necessary for annual submissions to ERA, as well as additional information required for price revisions. A suggested minimum set of information requirements is presented below.

Table 1.1 Suggested scope of submissions to ERA

Annual submission	Price application
Financial (regulatory) accounts	As for annual submission plus:
Asset register documentation	Specification of future investments
Specification of investments	Breakdown of budget
Summary of customer information (Distrib)	Pricing methodology description
Records of energy sales, exports & purchases	Load profiles & losses information
Availability (Generation)	Proposed tariffs & connection fees
Quality of supply measures (Trans & Distrib)	

2 The revenue requirement

Prices in all parts of the industry are based on the revenue requirement of the relevant parts of the business. We review here how the revenue requirement has been calculated.

Section 2.1 presents the composition of the revenue requirement for each part of the business, as presented in the Excel spreadsheets provided to us. The following sections examine each component in more detail. Annex A contains more detail on each element of the revenue requirement.

2.1 Total revenue requirement

The figures presented here come from the Excel spreadsheets submitted as part of the price application on 8 February 2001. The 1999 figures are based on UEB's 1999 accounts. The 2000 figures are estimates extrapolated from 1999 figures, and the 2001 figures are based on UEB's budget.

The ERA should be aware that there may be windfall profits or losses as a result of actual 2001 figures differing from budgeted figures. Given that certain cost elements, such as operating expenses, represent allowances, this implies that the companies have incentives to improve efficiency and so would capture windfall profits. An exception to this may be interest expenses, where it is acknowledged that UEB is undergoing debt restructuring, and interest expenses may well vary significantly from those budgeted for. In this case, ERA may wish to insist on an adjustment in 2002 to account for this.

Generation

The revenue requirement for 2001 is made up of elements presented in Table 2.1. The 2001 figures are also compared with 2000 and 1999 figures.

Table 2.1 Revenue requirement for generation

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Operating expenses	13,735	13,735	7,881	0%	-43%
Depreciation	5,807	5,818	14,883	0%	156%
Interest expense	8,425	28,162	13,698	234%	-51%
Return	-	-	-	0%	0%
Tax	-	-	-	0%	0%
TOTAL	27,967	47,715	36,462	71%	-24%

The increase in revenue requirement from 1999 to 2000 is due to a large increase in interest expenses.

There is a reduction in revenue requirement from 2000 to 2001 and this is due to decreases in operating costs and interest expenses. These decreases are partly offset by increases in depreciation expenses. These issues are examined in more detail in Annex A.

Transmission

Table 2.2 presents the revenue requirement for transmission for 2001, and compares it with previous years.

Table 2.2 Revenue requirement for transmission

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Operating expenses	6,864	6,864	17,482	0%	155%
Depreciation	5,119	5,155	7,899	1%	53%
Interest expense	4,206	7,009	12,176	67%	74%
Return	0	0	0	0%	0%
Tax	0	0	0	0%	0%
TOTAL	16,188	19,028	37,557	18%	97%

The increase in revenue requirement from 1999 to 2000 is due to a 67 per cent increase in interest expenses.

This is followed by a 97 per cent increase in 2001 and this is due to increase in operating costs, depreciation and interest.

Distribution

Table 2.3 presents the revenue requirement for distribution for 2001, and compares it with previous years.

Table 2.3 Revenue requirement for distribution

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Operating expenses	33,470	33,470	29,209	0%	-13%
Depreciation	10,222	10,294	15,783	1%	53%
Interest expense	8,399	14,696	24,859	75%	69%
Return	-	-	-	0%	0%
Bad debt	4,500	3,933	10,272	-13%	161%
Tax	-	-	-	0.0	0.0
TOTAL	56,591	62,392	80,122	10%	28%

The 10 per cent increase in revenue requirement from 1999 to 2000 is entirely due to the 75 per cent increase in interest expenses.

This is followed by a 28 per cent increase in 2001 and this is due to increase in depreciation, interest and bad-debt. These increases are partly off-set by a reduction in operating expenses.

Total revenue requirement across the industry

Table 2.4 presents the total revenue requirement across the industry.

Table 2.4 Total revenue requirement

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Generation	27,967	47,715	36,462	71%	-24%
Transmission	16,188	19,028	37,557	18%	97%
Distribution	56,592	62,393	80,122	10%	28%
Total	100,747	129,135	154,141	28%	19%

Overall, costs increase by 28 per cent from 1999 to 2000, and this rise is due to increased interest expenses. Costs increase again from 2000 to 2001, due to increases in transmission and distribution costs.

2.2 Key issues in the revenue requirements

Annex A contains a more detailed analysis of the composition of the revenue requirements. The key issues arising from this are:

- **Allocation of operating costs:** The allocation of UEB's operating costs to Genco, Transco and Disco in 2001 differs significantly from 2000. This was queried with UEB and they responded that the difference arises from a more thorough and revised approach to cost allocation, although no documentation was submitted in support of this (see Annex J).
- **Interest expenses:** The allocation of interest expenses in 2001 was also different from previous years. This was queried with UEB and they responded with revised figures allocating interest in the same way as previous years, i.e. in proportion to asset values, as shown in Table 2.5.

There remains uncertainty regarding UEB's debt obligations due to ongoing discussions regarding debt restructuring. ERA should request to be updated on this issue as it progresses, and reserve the right to make adjustments to the tariffs to cater for any windfall losses or profits that may result.

Table 2.5 Revised interest allocation in 2001

	Interest (original)		Interest (revised)		Assets in 2001	
	Ushs mill	%	Ushs mill	%	Ushs mill	%
Genco	13,698	27%	31,318	62%	468,486	62%
Transco	12,176	24%	6,213	12%	92,938	12%
Disco	24,859	49%	13,202	26%	197,479	26%
Total	50,733	100%	50,733	100%	758,903	100%

- **Bad debts:** UEB was requested to justify the bad debt allowance of 6.9 per cent, which they did in terms of their experience in 2000.
- **Losses:** UEB was also asked to justify the loss estimates. They indicated that technical losses for 2001 should be on a par with experience in 2000, with expectations for a 3 per cent improvement in 2002 once the Urban Power Rehabilitation Project is under way. UEB comment that non-technical losses can be expected to reduce by 2 per cent per annum.
- **Load profiles:** UEB was requested to justify the load profile data, which they assert is based on 1999 information. However, no documentation of this was submitted. It will be appropriate for ERA to update this information for 2002.
- **Foreign exchange component:** UEB had requested (see Annex C) to increase the proportion of costs designated foreign exchange. UEB were asked to confirm the details of this request, which they did so. UEB further requested that operating expenses be indexed to inflation.
- **Electrification investment:** Domestic customers pay a connection fee lower than the costs of connection to the LV network (see Annex N). UEB informed us that the shortfall is not reflected in the investment figures for

distribution in the tariff model, but that the shortfall is too small to warrant an adjustment to the tariff.

2.3 Revisions to the revenue requirement

Based on the above, and the responses from UEB, the following revisions to the revenue requirement are necessary:

- Revise the allocation of interest expenses
- Reduce the allowance for non-technical losses by 2 per cent
- Revise the portion of the tariff designated foreign exchange.

Regarding UEB's request to index operating expenses to inflation, a mechanism is already in place to revise operating expenses on an annual basis in response to Ugandan inflation.

ECON has incorporated these adjustments into our price calculations presented in the following section.

3 Generation tariffs

3.1 Tariff methodology

Annex B presents the method used for calculating generation tariff and bills. The Annex also includes ECON's comments on this methodology.

The description of the method does not correctly refer to the impact of availability on prices. The application states that *“Each month, UEB will calculate an hourly Capacity Price equal to the Monthly Generation Cost divided by the product of the sum of the Maximum Actual Capacity for all generating units multiplied by the total hours in said month. Kiira will have a target availability of 96 per cent and Nalubaale will be rated at 162 MW and have a target availability of 95 per cent.”*

This statement should read *“Each month, UEB will calculate an hourly Capacity Price equal to the Monthly Generation Cost divided by the product of a) the sum of the Maximum Actual Capacity for all generating units, b) the target availability, and c) the total hours in said month. Kiira will have a target availability of 96 per cent and Nalubaale will be rated at 162 MW and have a target availability of 95 per cent.”*

Our main reservation is that the method will prove difficult to implement and monitor since it depends on measuring the availability of units, even when these units are not dispatched.

3.2 Prices proposed by UEB

The key price in the proposed algorithm is the Capacity Price. No values for this price have been proposed in the tariff application made by UEB.

UEB has proposed (see Annex C) that the target availability should be 96 per cent for Kiira and 95 per cent for Nalubale. The latter figure takes into account the fact that one 18 MW unit at Nalubale will be out for maintenance during 2001. Taken together, this gives a weighted average for the target availability of 95.3 per cent and maximum available capacity of 242 MW for 2001.

3.3 Prices calculated by ECON

ECON has translated the proposed algorithm and implemented it in spreadsheet form.

Taking the MAC as equal to 242 MW for 2001, and using the proposed availability figures gives a capacity price of 26,770 Ushs/MW. This price is based on an exchange rate of 1800 Ushs/US\$.

In 2002, the Capacity Price will decrease to 24,301 Ushs/MW once the unit out for maintenance at Nalubale is returned to service and as the revenue requirement for 2002 decreases in real terms.

There will be periodic adjustments in response to exchange rate fluctuations (and changes in Maximum Available Capacity). The spreadsheet developed by ECON allows the user to enter the exchange rate and Maximum Available Capacity for a specific period, and will then calculate the resulting Capacity Price.

Actual payments made by Transco to Genco will depend on availabilities on an hourly basis. It is important that Transco and Genco develop an approach to determining and verifying availabilities and hence monthly payments.

3.4 Recommendations for generation prices

Price structure

We recommend that ERA monitor the implementation of the proposed approach over the course of 2001 with a view to assessing the practicality of the proposal. A sketch of an alternative approach has been outlined in our report “Cost structure and tariff study for Uganda”, and could form the basis for a revised system of pricing between Genco and Transco.

Should the implementation of this method prove difficult, ERA should seek to design a new pricing approach from 2002 onwards.

Price schedule

We summarise in Table 3.1 the price schedule for generation prices calculated by ECON as part of this review. The price is based on an exchange rate of 1800 Ushs/US\$, a maximum available capacity of 242 MW and target availability of 95.3 per cent.

Table 3.1 Capacity price charged by Genco to Transco, based on an exchange rate of 1800Ushs/US\$

Maximum available capacity	Capacity price
242 MW	26,700 Ushs/MW

Updating of tariff

The pricing methodology allows for prices to be updated on a periodic basis to reflect changes in exchange rates and Maximum Available Capacity. We recommend that this updating be undertaken on a quarterly basis, i.e. every three months.

ECON has developed a spreadsheet model that allows ERA to implement these price adjustments. We recommend that ERA assume responsibility for managing

this process, setting up appropriate information exchange routines to enable it to do so.

In order to undertake the updating process, ERA should collate the following data:

Table 3.2 Data required for tariff updating

Data from the preceding three month period	Units	Source
The Maximum Available Capacity	MW	Genco
The average exchange rate	Ushs/US\$	Bank of Uganda

It should be noted that the average exchange rate of January and February 2001 is 1780 Ushs/US\$ - slightly lower than the rate of 1800 used in these calculations.

We recommend that on 2 April 2001 the spreadsheet model be used to determine the prices from that date onwards, making use of exchange rates from 1 January to 30 March 2001.

4 Bulk supply tariffs

The Bulk Supply Tariff (BST) is the tariff to be charged by Transco to Disco.

4.1 Tariff methodology

Annex B presents the method adopted for calculating bulk supply tariffs. The proposed tariff structure is a time-of-use tariff, with three different energy rates for peak, shoulder and off-peak periods.

The application states that *“Prices calculated in accordance with this methodology reflect actual transmission loss factors (costs are divided by energy sales delivered to UEB Distribution and exports at the transmission system connection points) However, in order to ensure that UEB Transmission is given an incentive to improve its operating efficiency, ERA may establish target loss factors in lieu of actual measured losses as the basis for determining the BST prices for all, or some component of, the costs of providing bulk power supplies”*.

We recommend that ERA does in fact use target transmission losses rather than actual losses.

Our other comments on this method are:

- The price method will result in large price increases in 2005 when Bujagali is commissioned.
- The price signal of a 20 per cent surcharge during the peak period is fairly muted, i.e. a relatively small premium over a long period.

4.2 Prices proposed by UEB

As with the generation tariffs, the proposal here is an algorithm rather than a set of prices. The spreadsheet provided as part of the tariff application gives an indication of what the average BST would be, based on the expected generation costs, demand and exports for the year. These are shown in Table 4.1.

Table 4.1 Bulk supply tariffs (Ushs/kWh), presented in spreadsheet model (after interest adjustments have been made)

	Peak	Shoulder	Off-peak
Time period	18:00 – 23:00	05:00 – 18:00	23:00 – 05:00
2001	70.1	58.4	43.3

The parameters driving these prices, apart from the revenue requirement and demand, is the load profile of demand supplied to Disco, the factor used to determine peak prices and the portion of export profits used to subsidise prices in Uganda. These are as follows:

- Percentage of energy consumed in peak: 30.5%
- Percentage of energy consumed in shoulder: 45.9%
- Percentage of energy consumed in off-peak: 23.6%
- Peak pricing parameter: 120%
- Portion of export profits used to subsidise Uganda prices: 0%

4.3 Prices calculated by ECON

ECON has translated the proposed algorithm and implemented it in spreadsheet form. Actual prices in each period will depend on generation payments, demand and exports in the previous period.

Using expectations of these variables, we find the following prices as shown in Table 4.2. The price for the first period (i.e. once the new pricing system is effective) is the price given for 2001, and agrees with the price presented in the spreadsheet model (see Table 4.1). Thereafter, price adjustments are made in accordance with the spreadsheet model provided.

Table 4.2 Bulk supply tariffs (Ushs/kWh), based on expected demand and exports and an exchange rate of 1800Ushs/US\$

	Peak	Shoulder	Off-peak
Time period	18:00 – 23:00	05:00 – 18:00	23:00 – 05:00
Price (Ushs/kWh)	70.1	58.4	43.3

4.4 Recommendations for Bulk Supply Tariff

Price structure

Our key recommendation is to accept the methodology for 2001, but to introduce a revised approach in 2002 which smoothes in the introduction of Bujagali costs over a longer time period. This revised method should also give consideration to a maximum demand element to the tariff to provide stronger price signals relating to the costs of peak demand.

ECON has been engaged to propose such a smoothing mechanism, and will submit a report in April 2001.

Price schedule

The recommended price schedule for the first price period is presented in Table 4.2.

Updating of tariff

The pricing methodology allows for prices to be updated on a periodic basis to reflect changes in actual costs of power purchases by Transco and sales to Disco. We recommend that this updating be undertaken on a quarterly basis, i.e. every three months.

ECON has developed a spreadsheet model that allows ERA to implement these price adjustments. We recommend that ERA assume responsibility for managing this process, setting up appropriate information exchange routines to enable it to do so.

In order to undertake the updating process, ERA should collate the following data:

Table 4.3 Data required for tariff updating

Data from the preceding three month period	Units	Source
The power purchase costs of Transco	Ushs	Transco
The amount billed by Transco to Disco	Ushs	Transco
The volume of energy purchased by Transco	GWh	Transco
The volume of energy exported by Transco	GWh	Transco

Prices for the first period cannot be based on the actual purchase costs of power and sales to Disco, since there will be no prior records. Hence, prices can only be updated as from the following period, i.e. commencing 1 July 2001.

5 End-user tariffs

5.1 Tariff methodology

Distribution tariffs contain two components:

- Power supply tariff, reflecting the costs of purchases from Transco. This is structured as an energy charge.
- Distribution tariff, reflecting the costs of distribution and retail services. This is structured as a monthly fixed fee, a maximum demand charge (not applicable to all customers), and an energy charge.

The method for calculating these tariffs is described in Annex B. The key issues arising from our review of this method and the way it has been applied are:

- The power supply tariff for off-peak Codes 22 and 32 does not reflect the lower Bulk Supply Tariff in off-peak.
- There are cross-subsidies from customers paying maximum demand charges to those who do not. This inflates prices to Codes 20 and 30.
- Distribution costs are allocated to MV and LV levels on the basis of the ratio 65:35. There is no justification given for this allocation.
- Distribution costs are allocated to customer groups largely on the basis of their energy consumption. Generally, asset costs are driven by peak demand and not energy consumption. A more cost-reflective method would be to allocate 1) assets costs – depreciation, interest, return – in proportion to share of system peak; 2) losses in proportion to energy consumption; 3) network operations and maintenance costs in proportion to either energy or share of peak demand, and 4) customer service costs in proportion to customer numbers. Given that there is little data on load profiles, it is difficult at this stage to implement this method.
- Maximum demand charges, based on historical figures, are too high. This is particularly the case for Code 30 customers, where the revenue from the maximum demand charge is in excess of the costs of supplying these customers.
- Maximum demand charges for Code 60 are levied in all periods – peak, shoulder and off-peak. This is inappropriate and should only be billed on the customer's peak demand in the month.
- The tariff application by UEB states that: "It is recognised that customers in rural areas impose higher costs on the system, and therefore they pay a

surcharge”. ERA has previously determined that the rural surcharge will not be levied.

We recommend that the prices be recalculated to remove cross-subsidies, and that the maximum demand charge element of tariffs be reduced. In future, ERA should re-examine distribution pricing in the light of additional load profile and cost of supply information.

5.2 Prices proposed by UEB

The prices proposed by UEB are presented in Table 5.1.

Table 5.1 Tariff schedule for end-user tariffs

	Power supply charge Ushs/kWh	Fixed monthly fee Ushs/mth	Maximum demand charge 1 Ushs/kVA	Maximum demand charge 2 Ushs/kVA	Distribution charge Ushs/kWh	Effective average tariff Ushs/kWh
Code 10	98.2	1 000	N/a	N/a	70.3	170.0
Code 20	96.5	10 000	10 000	N/a	70.3	210.8
Code 22					35.3	
Code 30	61.8	15 000	10 000	8 000	33.6	127.4
Code 32					21.4	
Code 50	99.8	4 000	N/a	N/a	62.5	166.5
Code 60		15 000				
Peak	66.9		10 000		37.6	
Shoulder	55.8		10 000		31.4	
Off-peak	51.2		5 000		21.4	

5.3 Cross-subsidies

The Minister of Mineral and Energy Development has indicated in a letter (see Annex L):

“Government Policy is that subsidies should be applied to buy down capital costs in order to reduce the tariff in the power sector, particularly in Rural Electrification. Government will also invest in consumer awareness and demand side management so that electricity is used in a prudent manner, which has an impact of lowering bills. Government is not in a position to support consumer subsidies.

As an internal policy, however the Authority while establishing a tariff structure may wish to adopt a certain level of cross-subsidisation and phase it out gradually as the industry develops”

Consequently, ERA should seek to establish prices with no cross-subsidies, but has the discretion to phase-in the elimination of cross-subsidies over time.

However, to retain cross-subsidies in the tariff will require significant price increases for Code 30 industrial consumers (approximately 50 per cent increase)

whereas the current proposals have a 15 per cent decrease for these consumers. The overall economic impact of large price increases for Ugandan industry will inevitably be negative.

For this reason we recommend that ERA look to implement the policy of removal of cross-subsidies in one year, i.e. 2001.

5.4 Prices proposed by ECON

Power-supply element of tariffs

We have calculated the power supply element of end-user tariffs to reflect the BST, taking account of technical and non-technical losses in each consumer group.

We have also made allowance for power-supply prices for off-peak codes 22 and 32 to reflect the lower costs of power during the off-peak period.

Distribution element of prices

In calculating the distribution element of prices, we have revised both the maximum demand charge, and the energy charges.

To determine the maximum demand charge, we have allocated the asset-related costs equally to the maximum demand element and the energy element of the tariff. Taking account of the 65:35 allocation of costs to MV and LV levels, this provides an approximate price signal of:

- 5,000 Ushs/kW/month at LV level
- 3,300 Ushs/kW/month at MV level

We have calculated the distribution element of prices with no cross-subsidies between user groups. The resulting tariff schedule is given below.

Table 5.2 *Tariff schedule for end-user tariffs, based on an exchange rate of 1800 Ushs/US\$*

Tariff code	Power supply charge Ushs/kWh	Fixed monthly fee Ushs/mth	Maximum demand charge 1 Ushs/kVA	Maximum demand charge 2 Ushs/kVA	Distribution charge Ushs/kWh	Effective average tariff Ushs/kWh
Code 10	103.6	1 000	N/a	N/a	76.2	183.8
Code 20	103.6	10 000	5 000	N/a	58.0	174.9
Code 22	72.5				17.1	
Code 30	68.9	15 000	3 300	3 000	25.5	82.5
Code 32	47.7				10.6	
Code 50	99.4	4 000	N/a	N/a	67.0	170.3
Code 60		15 000	3 000	3 000		82.5
Peak	77.2				28.6	
Shoulder	64.4				23.8	
Off-peak	47.7				10.6	

5.5 Recommendations on end-user tariffs

Tariff structure

We recommend that the pricing methodology be revised to remove the cross-subsidy from maximum demand charges to other consumer groups.

ECON has developed a spreadsheet that implements the revised method and this is submitted along with this report.

Price schedule

The recommended price schedule for the first price period is presented in Table 5.2.

Should the ERA wish to phase-out cross-subsidisation over several years, it will be necessary to make adjustments to this proposed schedule.

Updating of tariff

The pricing methodology allows for prices to be updated on a periodic basis to reflect changes in exchange rates and changes in the Bulk Supply Tariff. We recommend that this updating be undertaken on a quarterly basis, i.e. every three months.

ECON has developed a spreadsheet model that allows ERA to implement these price adjustments. We recommend that ERA assume responsibility for managing this process, setting up appropriate information exchange routines to enable it to do so.

In order to undertake the updating process, ERA should collate the following data:

Table 5.3 Data required for tariff updating

Data from the preceding three month period	Units	Source
The average exchange rate	Ushs/US\$	Bank of Uganda
The Bulk supply Tariff for the forthcoming period	Ushs/kWh	ERA

It should be noted that the average exchange rate of January and February 2001 is 1780 Ushs/US\$ - slightly lower than the rate of 1800 used in these calculations.

We recommend that on 2 April 2001 the spreadsheet model be used to determine the prices from that date onwards, making use of exchange rates from 1 January to 30 March 2001.

Annex A: Composition of revenue requirement

A.1 Operating expenses

In 2001 operating expenses decrease for generation and distribution, but increase for transmission. The table below shows operating expenses across all parts of the industry, and it can be seen that in 2001 a re-allocation of expenses from generation and distribution to transmission occurs.

Table A 1 Operating expenses (mill shillings)

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Generation	13,735	13,735	7,881	0%	-43%
Transmission	6,864	6,864	17,482	0%	155%
Distribution	33,470	33,470	29,209	0%	-13%
Total	54,069	54,069	54,571	0%	1%

This change in allocation of operating expenses was queried with UEB (see Annex H), and their response is reported in Annex J and summarised in section 2.2.

A.2 Depreciation expenses

These expenses are constant from 1999 to 2000, then increase by 81 per cent in 2001.

Table A 2 Depreciation expenses (mill shillings)

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Generation	5,807	5,818	14,883	0%	156%
Transmission	5,119	5,155	7,899	1%	53%
Distribution	10,222	10,294	15,783	1%	53%
Total	21,148	21,267	38,565	1%	81%

The increases from 2000 to 2001 are due to:

- The increase is particularly large for **generation**. This is explained by a 139 per cent increase in the asset base. The effective depreciation rate also increases slightly (2.33 per cent to 2.5 per cent) due to a change in relative weights of different assets, although depreciation policy remains the same.
- For **transmission**, the increase can again be explained by the change in asset base, plus an increase in effective depreciation rate (2.33 per cent to 3.2 per cent). Again, depreciation policy remains the same.

- For *distribution*, the increase is explained by an increase in the asset base, and a change from effective depreciation rate of 2.3 per cent to 3.1 per cent. Again, the depreciation policy remains the same.

Table A 3 Gross assets (mill shillings) – revalued assets

Item	Values (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 – 2001
Generation	248,889	249,376	596,462	0%	139%
Transmission	222,343	223,906	246,822	1%	10%
Distribution	444,042	447,163	508,024	1%	14%
Total	915,275	920,444	1,351,307	1%	47%

Asset values increase due to plant additions in 2000. The increase is particularly large for generation, where new units at Kiira power station have been installed in 2000.

Medium term financial modelling has used depreciation rates of 2.5 per cent for generation, 3.5 per cent for transmission and 3.5 per cent for distribution.

ERA should include in its schedule of price submission requirements an asset register so that depreciation allowances can be checked. This information has not been provided as part of this price application.

A.3 Interest expenses, return and tax

Return is zero in each case because the revenue requirement is designed to cover only interest obligations and not to earn a return on assets. For this reason, taxation is also zero.

Interest expenses increase for generation from 1999 to 2000, and thereafter decrease again. For transmission and distribution, interest expenses increase in both 2000 and 2001. While an increase in interest expenses for generation can be expected in 2000 due to the loans associated with Kiira power station, it is not clear why interest expenses would decline again in 2001.

The allocation of interest in 2000 to generation, transmission and distribution is in proportion to net asset values in that year, i.e. 56:14:29. However, in 2001 the allocation is 27:24:49 – very different from the ratios of net asset values in 2001 of 62:12:26.

These two issues were queried with UEB and as a result the allocation of interest was recalculated. The results of their new submission are presented in 2.2 and removes the anomalies identified above.

When comparing the total interest expenses in 2001 with the figures given in the loan analysis spreadsheet, there is a large discrepancy. The total in the loan analysis spreadsheet is sh 27,395 mill compared to sh 50,733 mill. This was queried with UEB and it is apparent that the loan analysis spreadsheet assumed that a portion of debt (approximately 50 per cent) would be written off. This assumption was later discarded given the uncertainty in negotiating UEB's debt

restructuring. ERA should be aware that this issue is ongoing and should keep informed of the status decisions regarding of UEB's debt.

Table A 4 Interest expenses (mill shillings)

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 – 2001
Generation	8,425	28,162	13,698	234%	-51%
Transmission	4,206	7,009	12,176	67%	74%
Distribution	8,399	14,696	24,859	75%	69%
Total	21,031	49,867	50,733	137%	2%

A.4 Bad debt expenses

Bad debt expenses only arise in the case of distribution because it is only distribution that has an interface with end-use customers.

The allowance for bad debts increase from 3.4 per cent in 2000 to 6.9 per cent in 2001. This increase may be considered a once-off allowance to cope with the losses expected with the programme of disconnection. However, ERA should expect the allowance to decrease again from 2002 onwards.

Annex B: Price methodology

B.1 Method for calculating generation tariffs

The method proposed for calculating generation tariffs (between Genco and Transco) has been described in the document contained in Annex H. In summary, the proposal is as follows:

- Genco will establish the Maximum Actual Capacity (MAC) of each unit by demonstrating the available capacity for each unit at least once per month.¹
- The Revenue Requirement for Genco will be converted to a Monthly Generation Cost (MGC) - presumably a proportion of the annual requirement - and Genco will then calculate an Hourly Capacity Price (HCP) for each month, where:

$$\text{HCP} = \text{MGC} / (\text{MAC for all units} * \text{hours in the month}) \dots\dots\dots (i)$$

- It is proposed that Genco should be paid the HCP multiplied by the MAC for each 24-hour period that the unit can be shown to be available during that month, regardless of whether or not it is generating.
- If a unit is not available, or is only partially available (due to either forced or planned outage), for any time during the 24-hour period, then:
 - the HCP applicable to that unit for that 24-hour period shall be reduced by 50 per cent, and
 - payment will only be made for complete hours that the unit is available, based on the 50 per cent HCP multiplied by the ratio of the actual unit capacity to the Maximum Actual Capacity (MAC).

An example is presented below:

During a 24 hour period, all units at Kiira (80 MW) were declared available, but one 18 MW unit at Nalabale (162 MW) was unavailable for 6 hours of the day. Given a Capacity Price of 26,700 Ushs/MW, payment would be calculated as:

Kiira:	80 MW * 26,700 Ushs/MW * 24	= 51 264 000 Ushs
Nalabale:	144 MW * 26,700 Ushs/MW * 24	= 92 275 200 Ushs
	18 MW * 50% * 26,700 Ushs/MW * 18	= 4 325 400 Ushs

Comment

ECON has commented on this proposal in our report “Cost structure and tariff study for Uganda”. Our main comments are edited and reproduced below.

¹ It is not clear to whom the availability capacity should be demonstrated – would it be the ERA, UEB transmission, or another authority?

- The algorithm as outlined above will only allow the Genco to achieve its full revenue requirement if availability is 100 per cent for every hour of the year. Both planned and unplanned outages mean that this is unrealistic. This can be corrected by setting a target availability and altering equation (i) to read:

$$\text{HCP} = \text{MGC} / (\text{MAC for all units} * \text{hrs in month} * \text{target availability}) \dots \text{(ii)}$$

- There is an error in the calculation of the payment for capacity at reduced capability. At present it is expressed as:

$$\text{Payment} = 50\% * \text{HCP} * (\text{Actual unit capacity} / \text{MAC}) \dots \text{(iii)}$$

This gives a result in units of shilling/MW instead of shilling. The formula should read:

$$\text{Payment} = 50\% * \text{HCP} * \text{Actual unit capacity} \dots \text{(iv)}$$

- The penalty for reduced generating unit availability is seemingly arbitrary, i.e. 50 per cent of the normal per MW capacity payment. This figure does not appear to be supported by any documentation or analysis.
- “Policing” of generating unit availability will be a critical aspect of the proposed generating pricing, since all risks to Genco (and other generators), other than generating unit availability, will be passed through to the single buyer (Transco). It is not clear how this will be handled. In the short term, this should not present a serious problem, as the system is capacity constrained (at peak). However, it remains a problem for off-peak hours, and will become increasingly important during peak periods once there is spare/reserve capacity on the system.
- The question of transmission line outages is not covered in the pricing approach. Under these circumstances, Transco is still obliged to pay Genco on the basis of plant availability, but is unable to deliver energy to Disco. The principle should be that end-use customers should not pay for power that Transco was unable to deliver. This matter should be dealt with in contracts between Disco and Transco.
- Whilst the method selected, and described above, is certainly straightforward we have doubts about the workability of the proposals. On the one hand it is easy enough to verify power supply predicated on a maximum demand and energy tariff by metering which is both accurate and can be readily verified. On the other hand, we foresee difficulties with the selected method for the following reasons:
 - All the payments will depend on the "availability" of generating units and, more than that, on the capability of units when they are available. Our concern is that there may be a lot of scope for "manipulating" the rules.
 - Verification will be difficult. Who will do it? It almost certainly requires an independent authority respected by both Genco and Transco. It seems unlikely that the ERA would undertake this role, nor have the resources to do it.

B.2 Method for calculating bulk supply tariffs

The method proposed for calculating the bulk supply tariff (BST) charged by the Transmission company is as follows:

The costs included in the BST are:

- power supply payments to generators;
- transmission services – comprising direct costs (approved by ERA) plus depreciation of assets and existing interest obligations;
- reconciliation adjustments – required to reconcile its bulk supply costs with revenues received from Disco, and approved by ERA;
- export contribution – the difference between the export sales revenue and the average bulk supply cost.

Bulk Supply Costs (BSC) are then calculated as:

$$\begin{aligned} \text{BSC} = & (\text{Power supply} + \text{Transmission costs}) * (\text{Sales to Disco} / \text{Total sales}) \\ & + \text{reconciliation adjustments, if any} \\ & + \text{export contributions, at discretion of ERA..... (v)} \end{aligned}$$

Each year Transco will define the peak (not to exceed 8 hours per day), shoulder and off-peak periods. Loss factors will be calculated for each period based on actual measurements of generation and consumption for the previous month. In practice, ERA should establish loss factor targets as an incentive for Transco to improve its operating efficiency.

The BST price during the shoulder period will be the total Bulk Supply Costs divided by the sum of energy sales to Disco plus exports.

The peak period price will be the shoulder price multiplied by a peak period factor proposed by Transco and approved by ERA. A factor of 1.20 has been proposed.

The off-peak price will be determined by the total bulk supply costs less the revenues from the peak and shoulder periods divided by the energy consumed during the off-peak period. The tariff model makes use of load profile information in which 22 per cent of energy is consumed off-peak.

Exports will be sold on long term contracts and may generate trading profits, or losses, in hard currency. Trading profits may be used to support the connection of rural consumers through the Rural Electrification Fund.

The BST, as presently proposed allows all risks to be passed through to consumers. It is not clear however whether this includes export power risk. It is stated in the proposed transmission tariff that any profits or losses from exports should be retained in a special account. The ERA would be informed about the status of the account on a monthly basis and the contribution (profit or loss) from exports may, at the discretion of the ERA, be included in the Bulk Supply Costs.

Comment

ECON has commented on this method in our previous report. These comments are edited and reproduced here.

We believe there is an error in the algorithm described above. Equation (v) should read:

$$\begin{aligned} \text{BSC} = & (\text{Power supply} + \text{Transmission costs}) \\ & + \text{reconciliation adjustments, if any} \\ & + \text{export contributions, at discretion of ERA (vi)} \end{aligned}$$

This is because the BST during the shoulder is determined as:

$$\text{BST (shoulder)} = \text{BSC} / (\text{Sales to Disco} + \text{Exports}) \text{ (vii)}$$

Further, if ERA is to set a target transmission loss for Transco, rather than allow Transco to be automatically rewarded for actual losses, then equation (vii) should be expressed as:

$$\text{BST (shoulder)} = \text{BSC} / (\text{Energy purchases} * (1 - \text{Trans Loss Target})) \text{ (viii)}$$

Where Energy purchases refers to all energy purchases, including those for export. Trans Loss Target refers to the loss target set by ERA for Transco and applies to both losses on power exported and losses on sales in Uganda.

B.3 Method for calculating end-user tariffs

The methodology for calculating these tariffs, as we can detect from an examination of the spreadsheet model submitted by UEB to ERA on 8 February 2001, is described below.

Standing charges and demand charges

These elements of the tariff are retained at existing levels in the price application made by UEB.

Power supply

The power supply price for each customer group is calculated as the average of peak, shoulder and off-peak elements of the BST, weighted by the proportion of energy consumed by that group in each time period. The power supply price is also adjusted for losses to that customer group.

There is no differentiation of the power supply price for off-peak tariffs (i.e. Code 22 and 32) to reflect the reduced cost of Disco's power purchases during this period.

The weights are derived from the load profiles per customer group. The proportion of energy used in each time period per customer group is presented below.

Table B 1 Load profile information for customer groups

	Codes 10 & 20	Code 30	Code 50	Code 22 & 32
Peak	37.5%	35%	60%	0%
Shoulder	56.0%	65%	40%	0%
Off-peak	6.5%	0%	0%	100%
TOTAL	100%	100%	100%	100%

Note: Codes 22 and 32 are codes for energy consumed by codes 20 and 30 in off-peak periods

Distribution charges

Distribution charges are calculated in the following manner (and illustrated in Figure B.1):

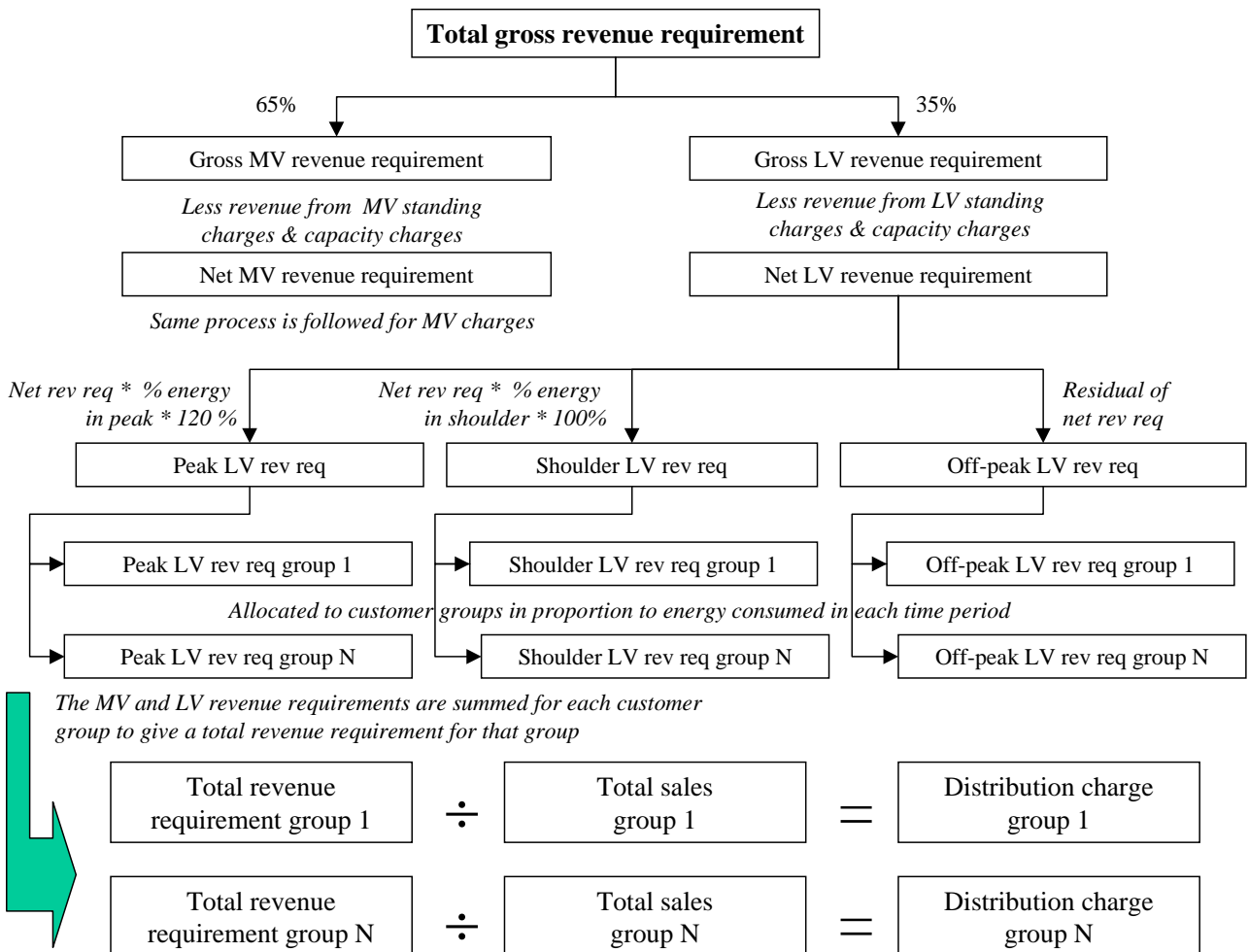
- The total revenue requirement for distribution is allocated to MV and LV networks according to the proportion 65:35. These form the basis for the calculation of MV and LV distribution charges.
- ***MV distribution charges:***
 - A net revenue requirement for MV networks is calculated as the gross revenue requirement for MV less revenue from standing charges and demand charges from customers on MV networks.
 - A net MV revenue requirement during the peak period is defined as the product of the net revenue for MV and the proportion of energy consumed during the peak period, multiplied by 120 per cent.
 - A net MV revenue requirement during the shoulder period is defined as the product of the net revenue for MV and the proportion of energy consumed during the shoulder period, multiplied by 100 per cent.
 - A net MV revenue requirement during the off-peak period is defined as the remaining revenue required.
 - The net MV revenue requirements per period are then allocated to all customer groups taking power in proportion to the energy they consume.
 - The revenue requirements per time period are then added to yield a revenue requirement per customer group. This monetary amount is then divided by the sum of energy billed per customer group to give an MV charge for that group.
- ***LV distribution charges:***
 - Similarly, a net revenue requirement for LV networks is calculated as the gross revenue requirement for LV less revenue from standing charges and demand charges from customers on LV networks.
 - Similarly, a net LV revenue requirement during peak, shoulder and off-peak is defined in the same manner as for MV
 - The revenue requirements per time period are then added to yield a revenue requirement per customer group. This monetary amount is then divided by the sum of energy billed per customer group to give an LV charge for that group.
 - Finally, the distribution charge for customers taking power on MV networks is defined as their MV charge. The distribution charge for

customers taking power on LV networks is defined as the sum of their MV and LV distribution charges.

The parameters driving this algorithm are

- the overall revenue requirement from distribution,
- the 65:35 allocation of costs to MV and LV networks
- the 120 per cent and 100 per cent factors applied to the allocation of costs to peak and shoulder time periods
- technical and commercial losses in MV networks (5 per cent and 4.1 per cent respectively)
- technical and commercial losses in LV networks (12 per cent and 18 per cent respectively)
- the load profiles and energy consumption of the individual customer groups.

Figure B.1 Illustration of calculation of distribution charges



It should be noted that the revenues from standing charges and demand payments are not credited to specific customer classes. This effectively means that those customers paying demand charges are subsidising those who do not. Thus, distribution fees paid by code 10 customers are subsidised by the demand charges paid by code 20 customers. This explains why the effective average tariff for code 20 is higher than code 10. A rough alteration to the algorithm to recognise this

would be to express the revenue from standing fees and capacity payments (per customer group) as unit revenue (sh/kWh), and subtract it from each group's distribution charge. This would result in revised distribution tariffs as shown below.

In the implementation of this algorithm, we note that LV customers are also required to bear a portion of the cost of revenue losses due to MV customers. This is an error, but only introduces a slight bias to the results.

Total distribution commercial and technical losses are taken equal to those in the supply and demand assumptions underlying the forecasts. It is further assumed that 64 per cent of the technical losses, and 77 per cent of the commercial losses occur at the LV level.

The ratio 65:35 to determine the cost allocation to MV and LV appears arbitrary. Using information from the Lahmeyer report, the ratio of replacement value of transformers and MV lines to LV lines and service connections is approximately 50:50.

The allocation of costs is in proportion to a customer's portion of total energy consumption, with some corrections made to penalise customer with low load factors (i.e. the 120 per cent factor applied to peak). Generally, asset costs are driven by peak demand and not energy consumption. A more cost-reflective method would be to allocate:

- 1) asset costs in proportion to share of system peak;
- 2) losses in proportion to energy consumption;
- 3) network operations and maintenance costs in proportion to either energy or share of peak demand, and
- 4) customer service costs in proportion to customer numbers. Given that there is little data on load profiles, it is difficult at this stage to implement this method.

This approach would require more information on load profiles and peak coincidence factors, but would be more consistent with international practice.

Annex C: Correspondence from UEB to URU – 01/02/01

The following letter was submitted by UEB to URU dealing with the price application.

Our Ref: PJM/fdnkl

1st February 2001

Mr Emmanuel Nyirinkindi
Director
Utility Reform Unit
Ministry of Finance, Planning & Economic Development
KAMPALA

TARIFF ADJUSTMENT

I refer to the meeting held in your offices on 22nd January 2001 with NVE, ERA and Econ to consider issues related to the work done by the Transaction Advisors on tariff.

Referring to the above mentioned meeting, I have now received minutes from ECON and would appreciate your confirmation of actions that must be performed prior to our submission to ERA.

Using the same numbering system as in the Minutes:

- 1.1 No further action other than in the first issue mentioned below with respect to interest charges.
- 1.2 UEB proposes a target availability of 96 per cent for Kiira Power Station. In the case of Nalubaale we propose that for 2001, the Station be rated at 162 MW (one unit at a time will be out permanently for maintenance work. This is to catch up on proper repair and maintenance that was not possible before the commissioning of Kiira.) and have an availability of 95 per cent. This reflects the current situation at Nalubaale.

The action required would be for the transaction advisor to reflect this change in the model.

- 1.3 As I understand the model, it follows UEB's Policy of not depreciating capital in the year that it is commissioned, therefore the impact of 2001 expenditure for depreciation purposes is nil. The interest cost of additional financing would be determined by whatever the market perceives the risk

to be inherent in the industry in general and the Transmission Company in particular. I believe that the transaction advisor could guide us better with an assumption here. The UEB budgeted cost of capex in 2001 for Transmission is Ushs19,646 billion. This amount however includes work worth Shs 6,92 billion on substations and interconnectors below 132kV. This should therefore be added to the Distribution investment for 2001.

Action required is concurrence that our understanding is valid and to make adjustments to the data inputs as appropriate.

- 1.4 The first actions required under this point (bullets 1 and 2) concern the submission of substantiation documents to the Electricity Regulatory Authority (ERA) at the time of application. We understand that the assumptions were derived from data obtained by the transaction advisors from UEB. In the interest of saving time, we request that the advisors prepare an appropriate document for UEB to use.

The next action is for the price to be calculated using a rolling 3 month average for export sales. We request that changes be made in the model to reflect this.

The final action under this item is for the description to be changed in the advisor's documents (now the document to be used by UEB as part of its application).

Please confirm this will be done.

- 1.5 We understand the model to allow only one depreciation percentage per company to be applied for calculations. We also understand that the average percentages assumed in the model reflect past averages in UEB. Again in the interest of saving time we request that your advisors prepare a document reflecting the make up of the average used in the model.

- 1.6 We have just closed the billing for 2000 and the distribution losses at the end of 2000 are slightly higher than our estimate of 30 per cent. They are 34.7 per cent. The calculation should reflect this. We are in the process of confirming that a level of bad debts of 6,9 per cent is appropriate. It reflects less than our average under collections against billings from month to month and includes payments by Government. UEB will write the appropriate explanation in the cover letter to the application document.

Notwithstanding the minute reflecting that there is no cross subsidy among capacity paying and non capacity paying customers, I have received notification from ECON that they have reviewed the matter and stand by their original comment. Seeing that the ERA will no doubt take ECON's advice on this matter, I believe it is important for the designers of the model to liaise with ECON and work out an acceptable solution with regard to tariff calculation in the model.

The next bullet requiring action is documentation justifying the MV & LV ratio and load profiles to determine consumption per consumer group. Once again we understand that the data was originally sourced from UEB but again, to save time it would be appreciated if the advisor could prepare appropriate documents for our submission.

The designer should also remove the 20 per cent surcharge from the document and model.

- 1.7 The final issue regarding the tariff adjustment application for 2001 is that of application documentation. We would request that the advisors make the changes to the document “2001 UEB Tariff Restructuring” and the calculation model as agreed in the meeting and discussed in this letter and submit to UEB for successful completion of the application submission task.

With respect to UEB’s review of the model we have three important issues requiring your further assistance:

1. **Interest on Loans**

The current calculation reflects interest charges on loans for six months of the year. Two issues arise: the time factor and clarification on Government Policy with regard to interest charges on loans not excused or converted to equity.

With respect to time we believe that it (time) should reflect the period in 2001 that the successor companies are active. Please confirm.

With respect to interest charges we note that the calculation of interest is based on all loans continuing as before, albeit for six months. This contradicts our understanding that Government proposes to turn most of the debt to equity and impose back to terms between lenders and UEB for those loans that will remain. Whilst we understand that lenders consents and Government approval must still be obtained, this item has a sizable impact on the tariff. To apply for tariff adjustment on the current basis and have the interest cost dramatically adjusted shortly thereafter would send inconsistent signals to customers.

Your guidance in this matter is requested.

2. **Export Sales**

The model as presently constituted assumes export sales of 300 Gwh per annum. It has recently come to our attention that our buyers do not have a continued appetite for this volume at current prices. Our view is that the assumption should be closer to what is envisaged in our contract, i.e. 113 Gwh.

Should this adjustment be made we believe the impact on the average tariff would be an increase of approximately 7 per cent or 8 per cent higher than is the case before the adjustment.

Your view on this would be appreciated.

3. **Currency Exchange Fluctuations**

It is our understanding that currency fluctuations in the model are catered for only on investments. If this be the case then a model should be modified to allow calculation of currency fluctuations on interest payments as well as on a portion of “repair and maintenance costs”. The costs in the three successor companies that need to be linked to currency fluctuations in 2001 are:

Generation	-	Ushs 1bn
Distribution	-	Ushs 3.2bn

Transmission - Ushs 1.6bn.

These costs were derived assuming a rate of 1900 Shillings to the dollar.

Whilst it is accepted that UEB is the institution responsible for the tariff adjustment application it should also be acknowledged that given the fact that we have very limited capacity in the field of tariff calculations and also that UEB only received the tariff document and calculations within the last few weeks, our application submission will rely almost completely on continued support and input from the Privatisation Unit in general and its advisors in particular.

In the time available prior to submission of the application, UEB is very reluctant to take responsibility for making any adjustments to the calculation model. It would be far too risky, seeing that the model was not designed as a user friendly tariff calculation tool. We would not want to compromise the model's integrity by making changes which we do not understand the impact of. I trust that you concur that any adjustments, whether they be data input or calculation changes, be done by the designers.

I look forward to your positive and timely response. Once this is received UEB will be in a position to submit the tariff adjustment application.

PAUL J MARÉ

c.c. General Manager (F& IT)

General Manager (S)

Annex D: Tariff application by UEB – 08/02/01

Our ref: PJM/fdnkl

8th February 2001-03-26

Mr Ben Dramadri
Chairman
Electricity Regulatory Authority
Communications House
KAMPALA

TARIFF AND LICENCE APPLICATION

I refer to the tariff work done by the transaction Advisor to the Utility Reform Unit and the subsequent amendments agreed thereto in the meeting held on 22nd January 2001.03.26 Following on that meeting UEB has reviewed its data inputs and calculated tariffs for the three Successor Companies to be formed in accordance with UEB's Privatisation process. The Distribution Company tariff will be utilised by UEB until the successor companies are formed. Attached are schedules reflecting the input data and the resultant tariffs.

I would like to highlight certain key changes in data that have been made since the original document was reviewed by ERA.

1. It has been assumed that there will be no ERA Levy other than the = 3 per cent maximum mentioned in the act.
2. UEB has calculated interest due on existing loans with Government at existing rates. This has the largest impact on the tariff.
3. Exports have been revised from 300 GWh to 113 GWh which more closely resembles current levels.
4. Depreciation split between the successor companies is a best estimate but will be revised upon capture of assets into the relevant assts registers

I would request that prior to the finalisation of the concessions, UEB or the successor companies be granted the opportunity to apply to ERA to review the tariffs from Generation and Transmission. The reason for this is the successor companies to confirm the split of costs and resources between them as allocated

form UEB. The price to the end customer would not be affected in this process as it merely reallocates costs from one company to the other.

Given that the revision of tariffs is a prerequisite to the final lender approvals for the Bujagali project as well as the Power IV loan, UEB is available to react without delay to the ERA's questions and directions. To sustain profitability, UEB's 2001 budget assumed an increase in tariffs. To receive the ERA's decision as speedily as possible for this reason too, would be most appreciated.

Concerning the license application, UEB hereby applies for temporary licenses for the Successor Companies for the period until the private concessionaires take over. The successor companies will be:

- | | |
|----------------------|---|
| Generation company | - The Nalubale and Kiira power stations |
| Transmission company | - Will also act as system operator,
Exporter/importer and Bulk supplier |
| Distribution company | - Retailer and exporter/importer to Rwanda |
| Holding company | - Holding loans, some assets and isolated
generators and distribution system |

The name of the successor companies are not yet known but will be advised by the Minister of State for Finance (Privatisation) as soon as they are known.

I look forward to a mutually satisfactory conclusion.

PAUL J MARÉ

Annex E: Correspondence from URU to UEB – 08/02/01

8th February 2001

Mr Paul Maré
Managing Director
Uganda Electricity Board
Amber House
Kampala

Dear Mr Maré

Re: Tariff Adjustment

Your letter dated 1st February (PJM/fdnkl), and the subsequent meetings between UEB and URU refer.

I believe that in our recent discussions we have come to a common understanding on issues 1.1, 1.2, 1.3 and 1.6 raised in your letter, and on the sub-sections regarding interest expense, exports and currency exchange. In order to assist you in completing the tariff application, the Transaction Adviser team has reflected these changes in the tariff model. I request that you highlight these amendments in your submission to the ERA, in particular those relating to interest expense and the volume of electricity exports.

Points 1.4 and 1.5 of your letter refer to instances where the ERA has requested documentation to support certain assumptions, such as the availability of the generation plant and the calculation of depreciation rates. In this regard I request you to note that it was not part of the Transaction Adviser's terms of reference to investigate these issues in detail, and the assumptions included in the model at present are therefore based on observations of UEB past practice and the experience of the Transaction Advisers from other countries. While URU will happily support you in these tasks, it is more appropriate that UEB should take the lead in providing such documentation to ERA.

I would also like to clarify URU's expectations with regard to the tariff application process. The November 2000 report on tariff structure and level made by the Transaction Adviser team was intended as a recommendation to both Government, ERA and UEB. URU's role in the process is to provide objective technical support to UEB and ERA, given that both organisations are relatively new to tariff regulation. It is therefore not appropriate for the Transaction Adviser to prepare the final form of tariff application on behalf of UEB as requested in

section 1.7 of your letter. Rather, I would like to propose that you submit your tariff request, along with supporting spreadsheets to ERA, while referring to the Transaction Adviser's earlier recommendations and the consensus reached to date on tariff structure.

In response to your point that UEB is apprehensive about making changes to the tariff model, I would like to propose that UEB personnel should be given more training in its use. I think this would be especially valuable to the managers in the successor companies who will be responsible for regulatory affairs and future tariff submissions. If you are agreeable to this proposal, I request that you nominate members to undergo a short course of training from the Transaction Adviser team.

Lastly, I would like to assure you of the URU's commitment to supporting UEB throughout the process of tariff reform and privatisations.

Yours sincerely,

J Wright

For Director, Utility Reform

Annex F: First request by ECON to UEB for further information – 14/02/01

The following email was sent by ECON to UEB on 14 February 2001 requesting clarification of certain issues.

Dear Mr Mare

As you know, I've been asked to assist ERA review the UEB tariff application. We received information earlier this week and I have some (early) questions for you.

1. I've been provided with the set of spreadsheets from ERA. Can I confirm that this constitutes the tariff application, or is there a written submission as well?
2. The spreadsheets contain links to several sheets not provided. These include UEB Consolidated – Proforma financials A.xls, UEB Proforma accounts 1999 REV-B.xls, SS Inv.program.xls, Loan analysis.xls, Companies' Budgets 2001C.xls and UEB PROFORMA ACCOUNTS 1999D.xls. In fact, I have all of these except the last one, provided by PA Consulting in Jan this year. It's a fairly easy task to recreate the links to the versions of these missing spreadsheets that I have, but can I assume that there have been no changes to these spreadsheets since mid-Jan?
3. The pricing paper given to us last year (titled "2001 UEB Tariff Restructuring"), prepared by PA Consulting, contained a lot of detail on approach to pricing, including indexing of tariffs to foreign exchange rates, ways of calculating the payments to generation, the bulk supply tariff etc. Will this paper be part of the pricing application?
4. As mentioned above, the original pricing paper had proposals for indexing prices to foreign exchange rates with adjustments on a monthly basis and so on. Are you planning to implement these proposals this year? And is the ERA being asked to approve this price adjustment process as contained in this original paper?
5. The spreadsheets only give us end-user tariffs, although the information is there to calculate the transfer prices as well (i.e. the Capacity Price to be charged by Generation and the Bulk Supply Tariff to be charged by Transmission). Is UEB only applying for end-user tariffs, or also the transfer prices? Or will transfer pricing only be implemented from next year?
6. The calculation of the Capacity Price for generation requires a target availability, as we discussed at the meeting. Have you proposals for what such a target should be?

7. I notice in the spreadsheets that total losses, including technical losses across T&D as well as non-technical losses, amount to 38 per cent of generation. The data we had from 2000 had losses running at around 30 per cent. Didn't we agree to adjust loss estimates downwards to 2000 levels?
8. Was there any further discussion on the issue of cross-subsidies from consumers paying a capacity charge? As far as I can see, this remains a problem in the spreadsheets given to me. It gives rise to certain anomalies, e.g. the average effective tariff for Code 20 is 213 sh/kWh, whereas it is 177 sh/kWh for Code 10. Normally one would expect a larger customer (i.e. Code 20) to have a lower average price.
9. Can you clarify tariff Codes 22 and 32 for me? Are these Codes for customers who only use energy in off-peak, or is it the rate paid by Code 20/30 customers during the off-peak period? If a customer is on Code 22/32, what do they pay during other periods – Code 20/30 rates?
10. Is there such a thing as a Code 60 Time of Day tariff? Such a thing is mentioned in the original pricing paper, but does not appear in the spreadsheets or anywhere else.

Regards

Mark Davis

ECON Centre for Economic Analysis
PO Box 6823, St Olavs Pl, 0130, Oslo
Tel: +47 22 98 98 70
Fax: +47 22 11 00 80
<http://www.econ.no>

Annex G: Correspondence from ERA to UEB – 07/03/01

ERA requested additional information from UEB in the letter reproduced below.

7th March 2001

Mr. Paul Mare
Managing Director
Uganda Electricity Board
Amber House
KAMPALA

Dear Mr. Mare,

Re: UEB APPLICATION FOR ASSESSING 2001 TARIFF

As you are aware, ERA has contracted ECON as the technical advisor on tariff issues under ERA/NVE cooperation. Consequently, ECON has prepared follow up questions in addition to positive dialogue between you and Mark Davis of ECON with a view to getting more information on tariff.

We note that the application received from you has insufficient information on a number of key issues, such as justification for tariff increase, specification of preconditions and methodology for calculating the new tariffs. Too much of the preconditions and rationale in tariff application is specified in cells in the spreadsheet, attached to the application.

I suggest you send a new application that is comprehensive and self-explanatory which both the Authority and Management can understand. The following issues should be addressed:-

- Justification why the tariff increase is necessary
- Specify the methodology used to arrive at the suggested tariff.
- Specification of input information and preconditions

If necessary we can amplify the above issues.

Let me point out that the issue of cross subsidies (life line tariff) is a policy one, which falls under the jurisdiction of the Ministry of Energy and Mineral Development. We have, therefore, requested the Minister to give a clarification

on this matter. I strongly suggest that you should continue to base your calculation on the basis of no cross subsidies which you can, however, adapt it to your model at a later stage if the Ministry requests you to.

We are planning to finalize the tariff application by the end of April/beginning of May. This will, however, depend on how fast you respond to our request for additional information.

We would have liked to synthesize as much as possible the information received from you but owing to lack of internal capacity, we shall not be able to do that. We therefore, wish to point out that approval of the tariff in future will not mean that all basic documents and information received have been approved also. We reserve the right to look critically at the information received at a later stage and take appropriate measures in accordance with the Act in the event you have not complied with the relevant provisions of the Act.

Please feel free to give direct to ECON the necessary information with a copy of your correspondence to ERA were necessary.

We look forward to continued fruitful co-operation.

Yours sincerely,

Ben Z. Dramadri

CHAIRMAN/ERA

Annex H: Second request by ECON to UEB for further information – 13/03/01

The following letter was sent by ECON to UEB requesting further information.

UEB
Amber House
Kampala
Uganda

Att.: Paul Mare

Your ref.

Our ref.
34511

Place
Oslo, 13 March 2001

UEB Tariff application

I have been asked by ERA to collate any additional and outstanding queries with regard to the tariff application and forward these to you. I have attempted to do so below.

Operating expenses

1. I notice from the spreadsheets that the budget for 2001 implies some reallocation of operating expenses between G, T & D compared with previous years (see table below). Effectively some 43 per cent of G's operating costs have been reallocated to T, and 13 per cent of D's operating costs have also been reallocated to T.

Can you clarify this for me, i.e. confirm that this is the result of a reappraisal of cost allocation among the three groups?

Table H 1 Operating expenses (mill shillings) (from Tariff Calculations C.xls)

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Generation	13,735	13,735	7,881	0%	-43%
Transmission	6,864	6,864	17,482	0%	155%
Distribution	33,470	33,470	29,209	0%	-13%
Total	54,069	54,069	54,571	0%	1%

Interest expenses

2. Regarding interest expenses, I notice that the total interest expenses budgeted for 2001 is Ushs 50 733, with is considerably larger than the Ushs 27 395 given in the loan analysis spreadsheet. I assume this is because some interest was rolled over from the previous year. Can you confirm this is the case and clarify how the two figures relate to one another? I note in your letter to URU (1 Feb 2001) your comments regarding the proposal to covert existing debt to equity and hence an expectation that the interest burden will be reduced.

3. Also regarding interest expenses, I notice that the tariff model (Tariff Calculations C.xls) allocates total interest in 2000 to G, T & D in proportion to net asset values in that year, i.e. according to the ratio 56:14:29. However, in 2001 the allocation of interest does not appear to resemble the relative asset values. Can you clarify how total interest expenses have been allocated to the three business units?

Table H 2 Interest expenses (mill shillings) (from Tariff Calculations C.xls)

Item	Costs (sh million)			Increase (%)	
	1999	2000	2001	1999 - 2000	2000 - 2001
Generation	8,425	28,162	13,698	234%	-51%
Transmission	4,206	7,009	12,176	67%	74%
Distribution	8,399	14,696	24,859	75%	69%
Total	21,031	49,867	50,733	137%	2%

Bad-debts and losses

4. I note in your letter to URU dated 1 Feb 2001 that you were in the process of confirming that an allowance for bad debts of 6.9 per cent was appropriate. Can you inform me of the outcome of this process?

5. I note that the following loss information is included in the tariff model for 2001:
 - Transmission losses: 4.8 per cent of power supplied to the transmission system
 - Distribution losses: 34.7 per cent of power supplied to the distribution system, of which
 - Technical losses: 14.0 per cent
 - Non-technical losses: 20.7 per cent

Total distribution losses are thus set at 2000 levels. ERA may decide to set loss targets for 2001 equal to 2000 levels, but your view on reasonable expectations for improvements in 2001 would be valuable input.

Load profiles

6. I have collated below the relevant load profile information used in the tariff calculations. This is derived from the figures in the tariff model. Can you confirm that this information is appropriate, as it influences price determination and will constitute baseline information for the future? This data gives us an overall load profile of Peak = 30.5 per cent, Shoulder = 45.9 per cent and Off-peak = 23.6 per cent. I note that at present there is no energy consumed on Code 60, and so I have taken the load profile of any future consumption on this tariff equal to the combination of Codes 30 & 32.

Table H 3 Load profile information (from Tariffs 2001 Calc - C.xls)

<i>Proportion of energy consumed in each time period</i>							
	Code 10	Code 20	Code 22	Code 30	Code 32	Code 50	Code 60
Peak	38%	38%	0%	35%	0%	60%	10%
Shoulder	56%	56%	0%	65%	0%	0%	19%
Off-peak	6%	6%	100%	0%	100%	40%	71%
<i>Proportion of total energy billed consumed by each customer category</i>							
	Code 10	Code 20	Code 22	Code 30	Code 32	Code 50	Code 60
	59.0%	15.3%	2.2%	6.8%	16.4%	0.3%	0.0%

Foreign exchange component

7. At present the tariff model has a foreign exchange component of revenue requirement for each element of the business as follows:

- Generation: 78% of Ushs 36,462 mill
- Transmission: 53% of Ushs 37,557 mill (only transmission costs)
- Distribution: 64% of Ushs 80,122 mill (only distribution costs)

These percentages are calculated by deeming the foreign exchange portion of costs equal to the entire revenue requirement (for each element of the business) less O&M costs. An exchange rate of 1800 Ushs/US\$ is used in the calculations.

I note in your letter to URU of 1 Feb 2001 that you request a portion of the O&M costs in each company to be designated as foreign exchange expenses. Using your figures of Ushs 1bn, 3.2bn and 1.6bn for G, T and D respectively, and noting the exchange rate used of 1900 Ushs/US\$, this would increase the foreign exchange proportion as follows:

- Generation: 81% of Ushs 36,462 mill
- Transmission: 61% of Ushs 37,557 mill (only transmission costs)
- Distribution: 66% of Ushs 80,122 mill (only distribution costs)

Can I confirm that my interpretation of your request, as given above, is correct?

This seems to cover my outstanding queries. I believe once we have had an opportunity to clarify these matters, I will be in a position to submit my report to ERA.

In addition, I note your proposal with regard to target availability for Kiira and Nalubale.

Yours sincerely

Mark Davis

Annex J: Correspondence from UEB to ERA – 15/03/01

The following response was submitted by UEB in response to the queries from ECON contained in Annex E.

Our Ref: PJM/fdnkl

15th March 2001

Mr Ben Dramadri
Chairman
Electricity Regulatory Authority
P O Box 10332
KAMPALA

UGANDA ELECTRICITY BOARD TARIFF APPLICATION

Further to our application dated 8th February 2001 and ECON letter of 13th March 2001, hereunder are the responses to the seven issues mentioned in the letter:

1. Operating Expenses

Operating costs were previously split largely on the basis of manpower allocation. In the current tariff application costs have been more accurately split between the operating companies.

2. Interest Expenses

The loan analysis spreadsheet reflects 50 per cent of the then estimated interest bill for 2001. I believe this was to take into account the effect of converting debt into equity. However, in the absence of approved government policy regarding loans, the loan interest was recalculated to reflect the actual current UEB obligation.

3. Interest Expenses

An error was made in allocating the interest expenses across the successor companies. The allocation should be:

Generation	-	Ushs	31,318m
Transmission	-	Ushs	6,213m
Distribution	-	Ushs	<u>13,202m</u>
TOTAL	-	Ushs	<u>50,733m</u>

I attach revised calculation sheets to reflect the charges brought about by this revision.

4. **Bad Debt**

UEB is currently collecting about 90 per cent of its monthly billing. Notwithstanding efforts to collect arrears, including the use of debt collectors, the debt is growing at about 7 per cent per annum. Once security deposits can be effectively implemented then the trend will be reversed. This will take sometime to effect. The provision is therefore in our view justified.

5. **Losses**

Using 1999/2000 as an indicator we believe that a target of reducing non-technical losses by 2 per cent per annum is a reasonable one. The technical losses will start to show improvement towards the end of 2001 when the Urban Power Rehabilitation Project gets underway. Technical losses should reduce by about 2 per cent - 3 per cent between the last quarter of 2001 and the end of 2002.

6. **Load Profiles**

The data used for load profiling comes from 1999 invoicing. As this application is for a price adjustment for 2001/2002 it will be appropriate to review this data within 12 months of the Electricity Regulatory Authority's determination of this application.

7. **Foreign Exchange Component**

The ECON interpretation of the UEB request to link portions of the revenue requirement to movements in the United States Dollar to Uganda Shilling Exchange Rate is correct. On a related issue UEB also hereby requests that the operating expenses be linked to US inflation, as measured by the US Consumer Price Index, for the component linked for Foreign Exchange purposes and to the Uganda inflation as measured by the Uganda Consumer Price Index, for the balance of the operating expenses. The base date for such adjustment would be June 2001.

PAUL J MARÉ

Annex K: Correspondence from UEB to ERA – 15/03/01

UEB submitted additional documentation in March 2001 in support of the tariff application, in response to the letter reproduced in Annex G. This is reproduced below.

15th March 2001

Mr Ben Dramadri

Chairman
Electricity Regulatory Authority
Communications House
P O Box 10332
KAMPALA

UEB Tariff Application 2001

Thank you for your letter of 7 March and our subsequent clarification meeting held on 14 March.

In accordance with our understanding of the requirement of the ERA as expressed in its letter of 7 March and clarified at the above mentioned meeting, we now deal with the three issues highlighted therein.

Justification for tariff increase

Tariffs for electricity were last reviewed in 1993. With the advent of the new electricity act and the privatisation of UEB, it has become necessary to apply for a new structure of tariffs that will apply to the operating companies that will result from the privatisation. In the period between the last tariff review in 1993 and this application in 2001, costs have increased (CPI movement of approximately 50 per cent) and investments have grown. The exchange rate between the Ugandan Shilling and other foreign currencies has weakened substantially in the past 7 years (50 per cent depreciation). All these costs and investments need to be reflected in the selling price of electricity to ensure the viability of the sector.

Methodology used to determine tariffs

The following general principles have been used to develop the restructured tariffs applied for in our document of 8th February:

- The tariff is for one year, and is not intended to apply beyond that.
- The tariff assumes a full unbundling of UEB, as required by the Electricity Act of 1999
 - Therefore, separate tariffs are needed for the generation, transmission, and distribution businesses.
 - The tariffs for each are based on the nature of the respective businesses, including the specific risks and rewards involved.
- The tariff obtains full cost recovery, as required by the Electricity Act.
 - Therefore, separate costs are estimated for the generation, transmission, and distribution businesses.
 - Therefore, previous subsidies for some customers no longer apply.
 - Customers are charged based on the costs they impose on the system, rather than some other basis (such as their economic class, or type of premises).
 - It is recognised that customers in rural areas impose higher costs on the system, and therefore they pay a surcharge
- The tariff allows the investor a fair return on investment, as required by the Electricity Act.
 - Therefore, UEB will earn a return on its invested assets.
 - We expect UEB to pay Government a dividend.
- The tariff is restructured to remove certain anomalies.
 - Residential customers who run small businesses out of their houses will no longer receive lower tariffs than those who run businesses out of commercial premises
- The tariff will be supplemented by a schedule of separate Connection Charges to be established by the ERA to compensate UEB Distribution for its costs of connecting new customers to its system, to the extent that such costs are not recovered in tariffs.
- The tariff shall be adjusted periodically to compensate for changes in exchange rates and inflation as may be necessary to maintain the effectiveness of cost recovery through prices charged to consumers.

Tariff Structure

UEB Generation

The UEB Generation business consists largely of the Nalubaale and Kiira complex. These consist of the original plant and the newly commissioned extension.

The structure of tariff recommended for generation is **monthly capacity payments** to be paid by UEB Transmission (the bulk supplier), based on demonstrated available daily capacity, As follows:

- UEB Generation will develop an annual budget. In its budget, UEB Generation will be allowed to earn a return on its fixed investment. Together, these costs will be converted to a Monthly Generation Cost.

- UEB Generation will establish the Maximum Actual Capacity of each unit by demonstrating the available capacity for each unit at least once per month.
- Each month, UEB will calculate an hourly Capacity Price equal to the Monthly Generation Cost divided by the product of the sum of the Maximum Actual Capacity for all generating units multiplied by the total hours in said month. Kiira will have a target availability of 96 per cent and Nalubaale will be rated at 162 MW and have a target availability of 95 per cent.
- For each 24-hour period during which the generation company can demonstrate that the Maximum Actual Capacity of any unit is available for the full 24 hours, UEB Generation will be paid an amount equal to 24 times the hourly Capacity Price multiplied by the Maximum Actual Capacity of each such unit.
- If a unit is on outage or reduced capability (either planned or forced) for any of the 24 hours in question:
 - the hourly Capacity Price applicable to that unit for that day shall be reduced by 50 per cent, and
 - payment will be made only for all full (60 minute) hours (of the 24) that the unit is available, by applying the reduced Capacity Price (50 per cent of the normal rate per MW) to the actual unit capacity in each hour to the unit.

The reasons for this structure include the following:

- Precedent set by Bujagali, which sets forth capacity payments (not energy);
- Desirability of structuring the generation sector around the capacity form of payment, therefore enhancing chances of attracting future IPP's;
- Desirability of introducing the capacity payment form of compensation for generation as early as possible, thereby demonstrating Uganda's commitment to future development;
- Inability of generation company to control water flow through the Nile, due to riparian agreements, variations in climatic conditions or acts of God;
- Inability of generation company to control off-take of energy for sales to energy consumers (whether in Uganda, or for exports);
- Preference to set up new generation concession as a relatively low-risk business;
- Need to give incentive to Generation Company to keep units available, and to quickly repair units.

The result is a tariff that enables UEB Generation to recover its costs, and to earn a fair return. The result is also that UEB Generation is compensated for its available generating capacity and not for its sales of “kWh”, or “energy”.

UEB Transmission

The UEB Transmission business will be responsible for several things, including dispatch of the generators, operation & maintenance of the high voltage lines,

exports to neighbouring countries, system reliability, data acquisition services, and other technical works. UEB Transmission will also administer the wholesale market in Uganda, in its current embryonic form, as “single buyer”.

UEB Transmission will sell energy to UEB Distribution on the basis of the **Bulk Supply Tariff (BST)**. The structure of BST tariff recommended is a **per unit energy charge** (shillings per unit), with peak and off-peak components.

In calculating the BST, UEB Transmission will take several steps:

Cost of Service

- **Power Supply:** UEB Transmission will make monthly payments to UEB Generation, based on available generating capacity as previously described. These will be relatively constant, month-to-month amounts.
- **Transmission Services:** UEB Transmission will develop an annual budget covering its direct costs. In its budget, UEB Transmission will be allowed to earn a return on its fixed investment. Together, these will be converted to a monthly sum.
- **Reconciliation Adjustments:** UEB Transmission will determine the amount required to reconcile its Bulk Supply Costs and revenues obtained from UEB Distribution under its BST, as approved by ERA.
- **Export Contribution:** UEB Transmission will determine its **profit and loss on exports** by applying the difference between the export unit sales price(s) (based on long-term export contracts) and the average bulk supply cost each month. Any profits or losses from the exports will be retained in a special account. UEB Transmission will inform ERA each month of the results of its exports for the previous month, and the status of the account.
- **Bulk Supply Costs:** UEB Transmission’s monthly costs of bulk supply shall be equal to the sum of: (1) the total costs of Power Supply and Transmission Services, (2) Reconciliation Adjustments, if any, and (3) any Export Contribution amounts applied to such costs at the direction of the ERA.

Calculation of the BST:

- Each year, based on an analysis of system loads, UEB Transmission will define its peak/shoulder/off-peak periods (peak not to exceed 8 hours per day).
- UEB Transmission will measure the output of UEB Generation (energy in MWh), delivered to the transmission network, using its SCADA system, and will record the data periodically, but not less than hourly.
- Similarly, UEB Transmission will measure the consumption of UEB Distribution and export sales, and will record the data periodically, but not less than hourly.
- UEB Transmission will total both power generated and energy consumed during the established peak, shoulder and off-peak periods for the preceding month and calculate the actual transmission losses associated with each time period.

- The BST price during the Shoulder Period shall be set equal to total Bulk Supply Costs divided by total sales by UEB Transmission to UEB Distribution and exports.
- The BST price during the Peak Period shall be set equal to the Shoulder Period price multiplied by a peak period factor (e.g., 1.20) proposed by UEB Transmission and approved by the ERA.
- The BST price during the Off-peak Period shall be calculated by: (1) subtracting revenues calculated on the basis of the Shoulder and Peak Period prices as applied to the energy consumed during each period, respectively, from total Bulk Supply Costs, and (2) dividing this amount by the energy consumed during the Off-peak Period of the previous month.
- UEB Transmission shall calculate its Bulk Supply Costs and BST prices in sufficient detail, as ERA may direct, to permit the separation of costs and revenues related to purchased power supplies from those related to its role as Transmission Operator, System Operator or Bulk Power Supplier.
- Prices calculated in accordance with this methodology reflect actual transmission loss factors (costs are divided by energy sales delivered to UEB Distribution and exports at the transmission system connection points) However, in order to ensure that UEB Transmission is given an incentive to improve its operating efficiency, ERA may establish target loss factors in lieu of actual measured losses as the basis for determining the BST prices for all, or some component of, the costs of providing bulk power supplies.

The reasons for this structure include the following:

- UEB Transmission will also be responsible for taking certain risks; most notably the risk associated with capacity purchases under both the Owen Falls and Bujagali power purchase agreements. To the extent that it continues as “single buyer”, UEB Transmission may undertake other such risks in the future.
- UEB Transmission will also have the opportunity to obtain certain rewards, in exchange for taking some of these risks. Most notable of these rewards is the export of electricity for hard currency.
- In its capacity as central dispatch, and using its SCADA system, UEB Transmission will be in the best position to use the available data to convert tariffs from capacity payments to energy payments. UEB Transmission’s ability to export electricity will also enable it to best balance the needs of Ugandan consumers against exports.
- Exports will be sold on the basis of long-term contracts. To the extent that exports generate windfall profits for UEB Transmission, these may be distributed to customers in Uganda, or may be directed to the Rural Electrification Fund, as determined by the Minister of Energy as a matter of energy policy, with implementation undertaken by the ERA.

The result is a tariff that enables UEB Transmission to recover its costs, and to earn a fair return for investors (now Government). The result is also that UEB Transmission is selling bulk power “kWh” (energy) services. It has the data, the responsibility as single buyer, and the financial resources as exporter to serve as the point of conversion of capacity payments to an energy tariff.

UEB Distribution

The UEB Distribution business will be responsible for several things, including operation & maintenance of the medium and low voltage lines, supply (sales) to energy consumers, and expansion of the system.

The structure of tariff recommended for UEB Distribution is in two parts: **(1) a per-unit energy distribution charge** to be applied to all energy sold; an additional monthly per-customer charge, the **(2) standing service fee**, will also form part of the tariff.

In addition, UEB Distribution will preserve UEB's existing two-part tariffs, to the extent that they are judged by ERA to send appropriate price signals to consumers, such as:

- demand metering and two part (energy + capacity) tariffs for large consumers.
- time-of-use metering and peak and off-peak tariffs to encourage consumers to adjust their energy use in response to appropriate price signals.

UEB Distribution will purchase energy on the basis of the **bulk supply tariff (BST)**.

- The customer's BST will be printed as a separate line on the customer's bills.
- The distribution charges will be shown as separate items on each bill.

In calculating the distribution tariff, UEB Distribution will take several steps:

- UEB Distribution will develop an annual budget, for approval by the ERA. In its budget, UEB Distribution will be allowed to earn a return on its net investment in fixed assets.
- UEB Distribution will determine its **distribution charges** once each year. The charges will be based on the annual budget, divided by unit sales (or other billing parameters) recorded in the previous year.
 - In years in which generation availability has changed significantly (such as 2001 as compared to 2000), a normalisation adjustment will be developed and agreed with ERA.
 - The charge is set in advance based on historic energy use, thereby giving UEB Distribution (and its successor, the disco concession) the incentive to connect additional customers and to sell additional units.
- Loss adjustment factors will be included in the tariff to account for medium and low voltage network technical losses, and for non-technical losses. ERA will set these factors, and in doing so will ensure that UEB Distribution is given an incentive to improve its operations (especially as regards non-technical losses).
- UEB will restructure its customer classes into classes based on cost of electricity service (e.g., voltage level, size of service) rather than apparent occupation or economic class (e.g., domestic, commercial, industrial).
- Per-customer standing service charges will be retained at current UEB levels, in order that the bills of the smallest consumers be minimally

impacted. For example, if a customer used no energy in the month (perhaps because his equipment was out of service), he would receive no increase.

UEB Distribution will establish different levels of its distribution charge, as follows:

- Customers connected at higher voltage will receive a lower distribution energy charge (Shillings/KWh), reflecting the appropriate loss factor(s). Similarly, energy charges for those customers taking low voltage service will be adjusted upwards to compensate for the greater losses incurred.
- Larger customers connected with demand meters (over 50 kVA) and subject to separate demand charges will receive a reduction in the distribution energy charges per kWh. However, their demand charge will continue at 1999 UEB levels.

The reasons for this structure include the following:

- UEB Distribution will be the precursor of the distribution concession. To the extent that a cost-reflective and properly structured tariff can be established prior to the transaction, the transaction should be more attractive.
- UEB Distribution (and more notably its successor) will be responsible for taking certain risks, most importantly the risk associated with the investments required to reinforce the network and to connect new customers.
- UEB Distribution will also have the opportunity to obtain certain rewards, in exchange for taking some of these risks. Most notable of these rewards is the revenue generated by its tariffs. The connection fees obtained from new customers may also be a benefit, as may be proceeds from the Electrification Fund.

The result is a tariff that enables UEB Distribution to recover its costs, and to earn a fair return for investors (now Government). Another result is that UEB Distribution (and the distribution concessionaire in future) has financial incentives to connect new customers, and to promote growth.

Exchange rate adjustments to tariffs

Virtually all of the fixed asset investments to date and those under construction or planned for the future (including anticipated investments by future concessionaires) are denominated in foreign currencies. Since the Ugandan shilling has experienced significant depreciation against these other currencies in the past, it is necessary to adjust tariffs expressed and collected in Ugandan shillings for changes in exchange rates in order that prices remain cost-reflective. All investment-related costs must be repaid in the same or equivalent foreign funds with values comparable to the original amounts invested. Only operating costs incurred through local procurement of labour, materials and services are exempt from the necessity to make this periodic adjustment to prices.

Time is of the essence if value is to be retained (witness the sensitivity of forex exchange street prices to fluctuations in relative currency values). Therefore, price adjustments for foreign exchange changes must be made as a routine matter. An

Exchange Rate Adjustment shall be made regularly to each of the tariffs determined as described in this report as follows:

- On the 25th of each month, the average exchange rate of Ugandan shillings to United States dollars during the period commencing on the 25th day of the prior month and ending on the 24th day of the current month shall be determined based on data obtained from the Central Bank of Uganda (or such other source or sources as ERA may approve);
- All tariff prices to be applied to bills during the month next following the current month shall be multiplied by:
 - 1) the ratio of the average exchange rate determined for the current month to the average exchange rate determined for the month preceding the current month, and;
 - 2) further multiplied by an Exchange Rate Factor established separately for UEB Generation, UEB Transmission and UEB Distribution companies and approved by ERA that shall be expressed as a percentage equal to the ratio of costs related to foreign investments to the total amount of the costs of providing service for each of the companies.

Input Information and Preconditions

We understand this requirement to refer to the needs of ECON in assessing the application for the ERA. UEB has submitted input information, clarification and conditions that have been requested by ECON. For the sake of brevity I have not repeated them here. However should the ERA require it, we will naturally do so.

I trust that this covers the requirements of the ERA letter of 7 March. If there are any further requirements please let me know and we will submit them without delay.

Yours

PJM

cc Dr M. Davis - ECON

Annex L: Correspondence from MEMD to ERA – 15/03/01

UEB 186/292/01

15 March, 2001

The Chairman
Electricity Regulatory Authority
Communications House
KAMPALA

RE: TARIFF REVISION IN THE ELECTRICITY INDUSTRY

Please refer to your letter dated 14th March 2001 regarding UEB's application to revise the tariff.

Government Policy is that subsidies should be applied to buy down capital costs in order to reduce the tariff in the power sector, particularly in Rural Electrification. Government will also invest in consumer awareness and demand side management so that electricity is used in a prudent manner, which has an impact of lowering bills. Government is not in a position to support consumer subsidies.

As an internal policy, however the Authority while establishing a tariff structure may wish to adopt a certain level of cross-subsidization and phase it out gradually as the industry develops.

Syda N. M. Bbumba (Mrs.)

MINISTER OF ENERGY AND MINERAL DEVELOPMENT

c.c. Permanent Secretary
Ministry of Energy and Mineral Development

Annex M: Correspondence from UEB to URU- 16/03/01

Our Ref: PJM/fdnkl

16th March 2001

Mr Ben Dramadri
Chairman
Electricity Regulatory Authority
Communications House
KAMPALA

INTERIM LICENSES AND TRANSFER PRICING

I refer to our discussion on 14th March 2001 where we discussed several issues, amongst them being the legal arrangements for the Successor Companies during the period from incorporation (1st April 2001) up to finalisation of the tariff and license application.

Please consider the following:

1. License

Please issue a temporary license to the Successor Companies as follows:

Generation - generation and sale

Transmission - system operator, exporter, importer and domestic sales

Distribution - retailer, exporter, importer and generator

Statutory Company (UEB) - holding loans, assets and generating and selling power in non-grid systems.

2. Interim Transfer Pricing Proposal:

Until a deliberation is made on the tariff application, the Generation Company will charge the Transmission Company and the Transmission Company will charge the Distribution Company a monthly interim fee to cover the month's cash expenditure. Once tariffs have been determined by

the Electricity Regulatory Authority then the Companies can charge each other appropriately and set off these interim fees.

I believe this to be the most practical process and hope the Electricity Regulatory Authority agrees.

PAUL J MARÉ

c.c. The Permanent Secretary
Ministry of Energy & Mineral Development
Management Board

Annex N: Connection fee schedule – 16/03/01

Our Ref: PJM/fdnkl

16th March 2001

Mr Ben Dramadri
Chairman
Electricity Regulatory Authority
Communications House
KAMPALA

TARIFF PRICE APPLICATION

Further to our letter of 8th February 2001, I submit for the Electricity Regulatory Authority's consideration an application for connection fees to be charged by the Distribution Company.

1. Domestic Customers

The application is that the current Uganda Electricity Board charges are retained, that is Ush 80,000/= for a "no pole" service and Ush. 276,000/= for a "one pole" service. This will lead to a small under recovery in the year 2001 but will be amended in the tariff application for 2002.

2. All Other Customers

Full cost recovery. This is the current Uganda Electricity Board Policy and reflects the fact that no costs for customers in this category have been included in the budget or tariff calculation.

PAUL J MARÉ

c.c. Dr M Davis - ECON (Via E-mail)

Annex O: ERA Resolutions

Passed at the ERA Board meeting of 27 April 2001

Board Resolution 1: Generation price method

The proposed system for pricing output of Kiira and Nalubaale is provisionally accepted by ERA and should be implemented once the new tariffs become effective. Within four months of implementation, ERA will require UEB Transmission to report on the experience with this pricing system, specifically focussing on the arrangements for measuring and verifying plant availability.

Board Resolution 2: Bulk Supply Tariff method

The proposed system for pricing the Bulk Supply Tariff is accepted by ERA for implementation in 2001. From January 2002, a new method will be adopted by ERA. This amended method will smooth in the impacts of Bujagali costs. ERA will issue details concerning the proposed new pricing method before July 2001.

Proposed Board Resolution 3: End-user pricing method

ERA notes the method used to arrive at end-user prices, and recognises that this method has the potential to be improved once better load profile information is available. For prices in 2001, the method should be adapted so that:

- Reduce non-technical losses from 21% to 19%
- Adjust the off-peak power supply charges for codes 22 and 32 to reflect the off-peak Bulk Supply Tariff
- Reduce the maximum demand charges to Ush 5000 for Code 20, and Ush 3300 for Codes 30 and 60.
- Ensure that revenues from a customer's maximum demand charges are off-set against the price paid by that customer.

Board Resolution 4: Price schedule

ERA resolves that new price schedules will be effective from a date to be determined by ERA (see section 2). These schedules (excluding VAT) are:

Generation tariffs

Capacity fee = Ush 26 770 / MW per hour

Bulk supply tariffs (Ush/kWh)

	Peak	Shoulder	Off-peak
Time period	18:00 – 23:00	05:00 – 18:00	23:00 – 05:00
2001	70.1	58.4	43.3

End-user tariffs

End-user tariffs will contain a charge for power supplied, a fixed monthly charge, a maximum demand charge (applicable to Codes 20, 30 and 60), a distribution charge, and a life-line charge. The last item, the life-line charge, is a cross-subsidy required to support the retention of the lifeline element of Code 10 prices.

The lifeline element of Code 10 prices is as follows: Customers billed on Code 10 will have the first 30 kWh of their consumption charged at a life-line rate. Any consumption above this level will be charged at the higher Code 10 price.

Any customer making use of Code 22 or 32 will have consumption outside the off-peak period charged at Codes 20 or 30 respectively, and will be subject to the monthly fee and maximum demand charges of Codes 20 or 30 respectively.

The tariff schedule hereby approved by ERA is given below.

Tariff code	Power supply charge	Fixed monthly fee	Maximum demand charge 1	Maximum demand charge 2	Distribution charge	Lifeline charge
	Ush/kWh	Ush/mth	Ush/kVA	Ush/kVA	Ush/kWh	Ush/kWh
Code 10	103.6	1 000	N/a	N/a	76.2	10.0
	The first 30kWh per month will be charged at 50 Ush/kWh					
Code 20	103.6	10 000	5 000	N/a	58.0	10.0
Code 22	72.5				17.1	10.0
Code 30	68.9	15 000	3 300	3 000	25.5	10.0
Code 32	47.7				10.6	10.0
Code 50	99.4	4 000	N/a	N/a	67.0	10.0
Code 60		15 000	3 300	3 000		
Peak	77.2				28.6	10.0
Shoulder	64.4				23.8	10.0
Off-peak	47.7				10.6	10.0

Board Resolution 5: Periodic price adjustments

Prices will be adjusted on a periodic basis. The first adjustment will take place on 1 July 2001, and thereafter will occur every three months. ERA will issue the adjusted price one week prior to its implementation.

The most important parameters for the periodic adjustment are the proportions of the tariffs designated foreign exchange. These proportions are:

- Generation: 81%
- Transmission: 61%
(Note: adjustments of Transmission revenue requirement occur annually not quarterly)
- Distribution: 66%

Board Resolution 6: Public hearings and implementation of new prices

ERA resolves not to hold a public hearing, but will communicate the Board's decisions through a press conference.

The new prices will be effective from XXX.

Board Resolution 7: Phasing in the costs of Bujagali

ERA accepts the proposal submitted by ECON, but needs to investigate its practical implementation in Uganda, particularly with regard to location of the Fund and the tax implications. ERA will undertake this investigation, but further requests ECON to integrate the phasing-in mechanism into the quarterly price adjustment mechanism.

Board Resolution 8: Dealing with hydrological limitations

Should hydrological limitations lead to power shortages, then ERA will consider a request from the Distribution Company to adjust tariffs accordingly. This will be implemented by basing tariffs on a revised sales forecast, taking account of the lost sales due to hydrological limitations.

Board Resolution 9: Dealing with transmission outages

The Transmission Company should report to ERA on a quarterly basis the occurrence of transmission outages. This report should include an assessment of the quantity of lost load as a result of the outages, based on a comparison with demand in that period in preceding months.

ERA will include the estimate of lost load when it comes to updating the Bulk Supply Tariff, and will also adjust the sales forecast used to calculate Distribution Charges.

Board Resolution 10: Finalisation of regulatory framework

ERA accepts the description of the regulatory framework as contained in the document (*Draft Regulatory Framework*) prepared by ECON for ERA, with the

requirement that the description be amended to reflect ERA's policy on lifeline tariffs.

ERA requests NVE to negotiate with ECON for them to meet with the investment bankers and finalise the presentation of the regulatory framework based on this interaction and subsequent consultation with ERA.