

Report 22/01

Regulatory framework for Uganda

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Executive summary

Abstract

The Electricity Regulatory Authority's approach to regulation of electricity prices in Uganda is intended to balance incentives for improved operation with investment incentives. The process of awarding concessions for generation and distribution requires the regulatory framework to be presented to potential investors. This document forms the basis for such a presentation.

Background

The Electricity Regulatory Authority of Uganda (ERA) has amongst its responsibilities the duty to regulate electricity prices in Uganda. In the course of 2001, the generation and distribution assets of the Ugandan Electricity Board (UEB) will be leased to private operators. The award of these concessions will be on a competitive basis, with a bidding process anticipated to occur in the course of this year. As part of the process of awarding the concessions, information will be released to potential bidders. An important element of this information package will be ERA's communication on its approach to price regulation. This document sets out the basis for the content of this communication.

The presentation in this document is necessarily technical in nature, and is designed to remove ambiguity in the regulatory approach. The price adjustment formulae have been presented to show exactly how adjustments will be made. These adjustment procedures have been implemented in an Excel spreadsheet that has been developed on behalf of ERA.

The challenge of regulation of the power sector in Uganda is to reward investors fairly, yet to provide adequate incentives to minimise costs in the industry. This involves allowing for a reasonable return on investment, while ensuring the operating and investment efficiencies are achieved.

Regulatory approach

The ERA's approach to regulation fits with the restructuring of UEB into three separate entities: Generation, Transmission and Distribution. Transfer pricing in the industry will establish prices between generation and transmission; transmission and distribution; and between distribution and customers. ERA will regulate prices at each level.

Incentive elements of regulation and guarantees on rate of return

In calculating prices, ERA will determine the revenue requirement of each of the companies operating in the industry. This revenue requirement will constitute an allowance for operating costs (including any lease fees), depreciation of assets, a return on capital invested as well as taxation. As far as possible, ERA will attempt to introduce incentive elements into the regulatory system, for example by setting targets for station availability, reduction in operation costs and targets for losses.

The allowance for investment return in the revenue requirement will be based on the rate of return bid by the successful concessionaires. This rate will be applied to actual investment made over the period 2002 to 2005. From 2006 onwards, ERA plans to introduce incentives for investment efficiency, allowing companies to capture some of the gains from more efficient capital expenditure. In addition, ERA reserves the right to adjust the allowed rate of return on capital for 2006 onwards in the light of other interest rate movements in Uganda.

Price reviews

ERA will hold a new price review in the second half of 2002, and thereafter every 36 months. These price reviews will re-examine allowances for operating costs, losses and depreciation, and make adjustments based on any changes to investment levels.

Generation tariffs

In the course of 2001, a new system of generation prices will be introduced. This will calculate a Capacity Price based on the revenue requirement for the generating company and the maximum available capacity. The generating company will charge the transmission company a monthly sum based on this Capacity Price and the capacity made available for dispatch.

The capacity price will be revised on a quarterly basis to reflect changes in foreign exchange rates and maximum available capacity. A portion of the revenue requirement is designated "foreign exchange based", and this portion will be indexed to the dollar/shilling exchange rate.

ERA will evaluate this system of pricing generation in the course of 2001 and reserves the right to make amendments from 2002 onwards.

In 2002 the revenue requirement for generation will take account of inflation in 2001, the lease to be charged by the Government of Uganda, as well as the return bid by the concessionaire.

Bulk supply tariff

The transmission company will sell power to the distribution company and any other customers connected to the transmission system at a Bulk Supply Tariff. This tariff will combine the costs of transmission/system operation services with the costs of power purchases by the transmission company. The former will be based on the revenue requirement allowed for transmission and the latter will be based on power purchases from the generation company and imports.

The revenue requirement for transmission will reflect operating costs, depreciation of assets and an allowance to cover the cost of capital. This last item will be set equal to the costs of servicing the transmission company's debt.

The bulk supply tariff will be structured as a time-of-use energy charge. The average tariff will be equal to all costs divided by the sum of exports and sales in Uganda. This ensures that Ugandan consumers only pay for a proportionate share of the costs of supply.

The tariff will be updated on a quarterly basis to reflect actual costs and volumes of power purchases and exports. On an annual basis, the revenue requirement of transmission will be updated to reflect the effects of inflation and changes in foreign exchange rates.

From 2002, an adjusted bulk supply tariff will be introduced to gradually introduce the additional costs associated with the Bujagali power station. During the period 2002 to 2004, the bulk supply tariff will be above the average costs of supply, and from 2005 to 2007 prices will be below the average costs of supply. From 2008, prices will equal average costs.

End-user tariffs

End-user tariffs will consist of three components:

- Power Supply Charge, i.e. a pass through of the power purchase costs of the distribution company
- Distribution Charge, i.e. the costs of providing distribution and retailing services, based on the distribution company's revenue requirement.
- Lifeline Charge, i.e. Code 10 customers will be offered the first 30 kWh per month at a concessional rate, and all consumers will contribute to the cost of this through a special charge. The lifeline will be phased out over several years.

The power supply charge will be expressed as a unit energy charge for each tariff category. This price will be based on target losses established by ERA.

The distribution charge will be structured as either a two-part (basic fee plus energy charge) or a three part-tariff (basic fee plus maximum demand charge plus energy charge). Three-part tariffs will be charged to large commercial and industrial customers.

The lifeline charge will be structured as a unit energy charge and will be applied to all tariff categories.

End-user prices will be updated on a quarterly basis to reflect:

- Changes in the Bulk Supply Tariff (i.e. affecting the Power Supply Charge);
- Changes in exchange rates (a portion of the distribution company's revenue requirement will be indexed to the dollar exchange rate).

End-user prices will not be adjusted to reflect actual consumption levels, thereby giving the distribution company an incentive to increase sales above the expected sales established by ERA at the time of each price review.

ERA has proposed a methodology to structure end-use tariffs based on the allocation of costs to different customer categories. This allocation method will be used for prices in 2001 and 2002. ERA will reconsider revisions to this methodology in collaboration with the distribution concessionaire in the course of 2002.

1 Background

The Electricity Regulatory Authority of Uganda (ERA) was established in terms of the Electricity Act of 1999 with the responsibility to regulate the electricity industry in Uganda. The Authority consists of a Board and full-time professional staff.

Since the ERA was established, the electricity industry in Uganda has been in the process of being restructured. UEB is to be structured as three separate companies – Generation, Transmission and Distribution – with the generation and distribution assets to be leased to private operators. These private companies are expected to invest over the duration of the concession, particularly in the distribution system. In addition, a new power station at Bujagali Falls is expected to become operational in 2005.

ERA's principal regulatory duties comprise licensing and price control. This document sets out proposals for ERA's approach to price control, including the price controls for the first regulatory period, 2001 to 2002. It also sets out proposals for the approach to be adopted thereafter in setting prices at each price review.

The intention is that this document will form the basis for information provided by the ERA to bidders as part of the concession process.

1.1 Transfer pricing

Electricity prices will be set at three points in the industry:

- At the interface between generation and transmission;
- At the interface between transmission and distribution; and
- At the interface between distribution and the end-user.

The Transmission Company will act as the single buyer of electricity supplied to the transmission network in Uganda, and the sole exporter of power. Prices between generators and the Transmission Company will be negotiated between these parties, and will be subject to oversight and approval by the ERA. This document sets out the regulatory approach to prices between the Transmission Company and UEB Generation.

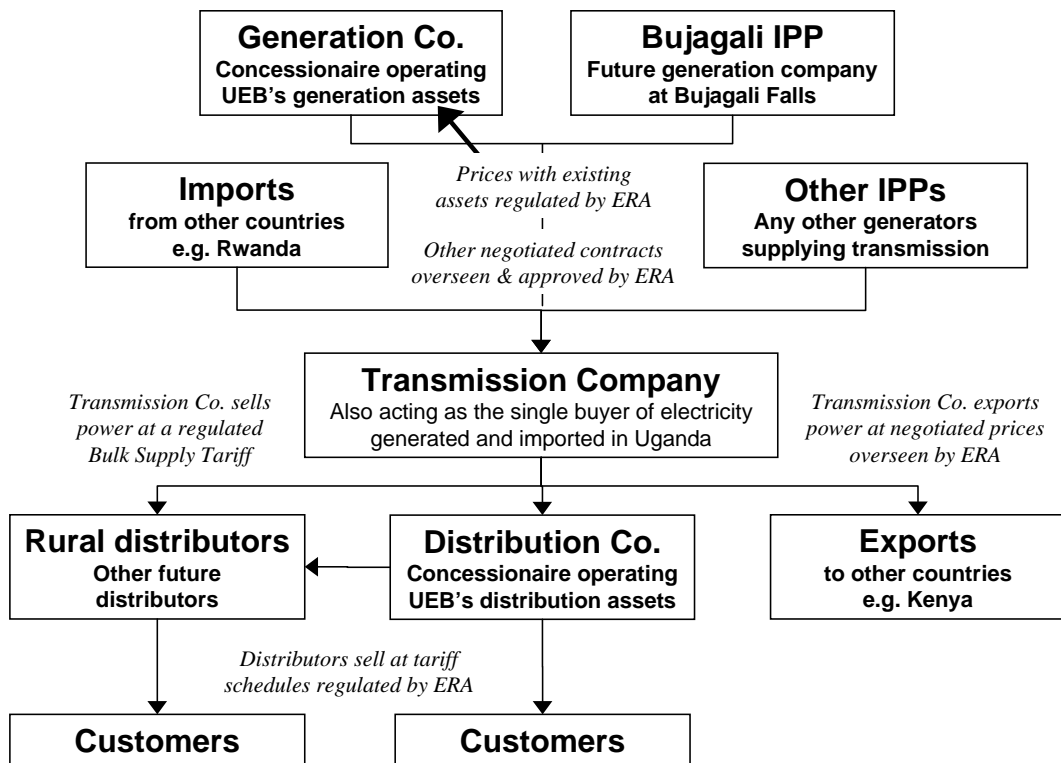
The Transmission Company will then sell power to any agent connected to the transmission network at a Bulk supply Tariff. This tariff will reflect both the costs

of power purchases from generators and the costs of transmission. The Bulk Supply Tariff is to be regulated by ERA, as set out in this document. The Transmission Company will export power at specially negotiated prices, but shall not export at prices below either the average or marginal cost of power purchases.

The Distribution Company will purchase power at the Bulk Supply Tariff, and sell it to end-use customers at a tariff schedule. This schedule of prices will reflect both the costs of power procurement as well as the costs of distribution and retail. These prices are to be regulated by ERA, as set out in this document.

Other distributors connected to the transmission network, e.g. rural networks, will purchase power at the Bulk Supply Tariff. If such distributors are connected to the distribution network, they will purchase power from the Distribution Company at the appropriate tariff. In future, ERA may allow such distributors to purchase power from the Transmission Company at the Bulk Supply Tariff and pay an appropriate “wheeling” charge to the Distribution Company. However, it should be pointed out that the pricing methodology adopted by ERA implies that there will be little difference between these two options.

Figure 1.1 Transfer pricing in the Ugandan electricity industry



1.2 Return on investment

The concessioning process will require potential concessionaires to bid their required return on investment. ERA will use this rate of return in its price calculations for generation and distribution.

ERA will adopt the following approach in calculating the return element of prices charged by generation and distribution:

- **For 2001 prices**, the return element of prices will simply be set at a proportionate share of UEB's interest obligations
- **For 2002 – 2005 prices**, the return element will be set using the rate of return bid by the successful concessionaire. The depreciation and return elements of prices will be calculated based on the expected investments to be made by the company. At each price review (i.e. end-2002 and end-2005), adjustments will be made to reflect actual investments made. That is, the asset base used for pricing calculations will be adjusted to reflect the actual assets owned by the company, and any under- or over-recovery due to investments differing from expected investment will be factored into the price calculations. In this way, the companies are guaranteed their required rate of return on actual investment.
- **From 2006 onwards**, the depreciation and return elements of prices will be based on the historical asset base owned by the company, plus expected investments. As before, the return calculation will use the rate bid by the successful concessionaire, with possible adjustment made to account for changes in interest rates in Uganda. Expected investments will be linked to targets, e.g. connection rates and quality of supply targets. At each three-yearly price review, the asset base for price calculations will be adjusted to the actual asset base, but no corrections for under or over-recovery will be made. In this way, the companies will receive their bid return on investment in they can achieve the targets within the investment allowance. They will be able to make additional returns if they achieve the targets at lower than anticipated investment. This mechanism is designed to introduce incentives for investment efficiency during the expansion of the distribution grid.

For the Transmission Company, there will be no bidding on rate of return. Instead, ERA will adopt the following approach to calculating the return element of prices:

- For historical assets (purchased prior to 2001), the return element of prices will simply be equal to a proportionate share of UEB's interest obligations. Depreciation will be based on revalued assets.
- For assets purchased thereafter, the return element will be calculated based on ERA's estimate of the Transmission Company's cost of capital.

The rate of return will be applied to capital employed by the company. This will be the sum of working capital plus the mid-point of the opening and closing asset values.

1.3 Incentive elements of regulation

Apart from the incentives related to investment efficiency discussed above, ERA will introduce other incentive elements into the price calculations. These include incentives to improve operating costs, and incentives to reduce losses.

Operating costs

Operating costs for generation, transmission and distribution for 2001 are based on UEB's budgeted figures. Thereafter, ERA will include allowances for operating costs into the calculation of the revenue requirement. These allowances will include targeted efficiency improvements in operations, implemented as real reductions in the allowances. If the company is able to reduce operating costs faster than the target, then it captures an additional financial reward.

ERA will set these targets for improvements in operating costs at each price review. Actual targets for 2001-2, and indicative targets for 2003-5 are given in this document.

In calculating distribution operating cost allowances for 2005 onwards, ERA will take account of the anticipated expansion in the customer base.

Losses and bad debts

Tariffs charged by the Transmission Company and the Distribution Company will include allowances for losses. The Transmission Company will charge for technical losses across the transmission network, and the Distribution Company will charge for both technical and non-technical losses. In addition, the Distribution Company's revenue requirement will include an allowance for arrears and bad debts.

At each price review, ERA will set the parameters to determine these allowances. If the companies are able to perform better than these targets, they will capture additional financial rewards. Actual targets for 2001-2, and indicative targets for 2003-5, are given in this document.

2 Generation tariffs

2.1 Introduction

The generation concessionaire (Genco) will lease and operate Nalubaale and Kiira power stations. Genco will sell power to the Transmission company (Transco) at a generation tariff. This tariff will be regulated by ERA. The structure of this tariff and approach to regulation is described below.

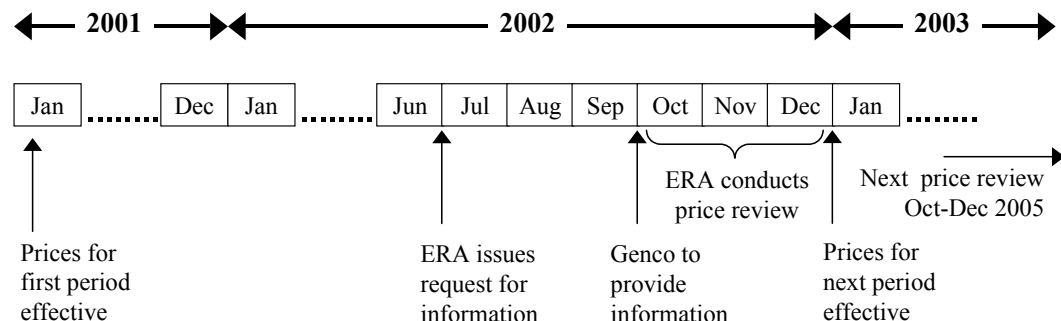
2.2 Timing of price reviews

The revenue requirement of Genco has been set by ERA for 2001 and 2002. The revenue requirement will be reset as from 1 January 2003, and thereafter reset every 36 months.

ERA will issue a request for information to Genco six months prior to prices being reset, and such information shall be provided within three months of the request. ERA will determine the scope and format of this information request prior to the call for information.

ERA will conduct a price review over the three month period prior to each resetting of the tariff. This price review will include analysis and verification of information provided by Genco, as well as public hearings conducted by ERA.

Figure 2.1 Illustration of timing of price reviews



2.3 Adjustment of prices between reviews

In between price reviews, ERA authorises Genco to adjust prices according to certain parameters. These parameters relate to foreign exchange rates, inflation, efficiency improvements and investment.

Annual adjustments for efficiency improvements

ERA will set efficiency targets for operating costs at the time of each price review. These will set a target productivity gain for Genco and will be used for price determination. These targets will be built into the annual revenue requirement calculated by ERA.

For 2001 and 2002, ERA has determined the revenue requirement in each year as shown in Table 2.1. This reflects the required operating cost target for each of these years. Note that the revenue requirement for 2002 will depend on finalisation of the lease fee for assets and the rate of return bid by the successful concessionaire.

Quarterly adjustments for foreign exchange rates

A portion of the revenue requirement will be designated the “Forex portion”. This portion will be fixed by the ERA at each price review period, and will remain constant until the next review period.

Each quarter (every three months), the portion of the revenue requirement designated the Forex Portion will be adjusted to reflect changes in the exchange rate. This implies that one portion of the revenue require will be adjusted by the new exchange rate, whereas the remaining portion will remain constant.

Consequently, each quarter Genco is required to adjust the revenue requirement according to the following formula:

$$\begin{aligned} G_Rev_Req [q,y] &= \text{Forex portion adjusted by new exchange rate} \\ &\quad + \text{Non-forex portion} \\ &= G_Rev_Req [y] * G_Forex * \frac{\text{Forex_rate [q-1]}}{\text{Forex_rate [0]}} \\ &\quad + G_Rev_Req [y] * (1 - G_Forex) \end{aligned}$$

Where

$G_Rev_Req [q,y]$ = annual revenue requirement for year y used to determine prices in quarter q.

$G_Rev_Req [y]$ = annual revenue requirement for year y as determined by ERA at the time of the price review

G_Forex = Proportion of tariff indexed to foreign exchange rates, as determined by ERA at each price review.

Forex_rate [q-1] = average shilling to dollar exchange rate in quarter q-1, as determined from Bank of Uganda statistics.

Forex_rate [0] = shilling to dollar exchange rate used by ERA at the time of the price review.

An example of implementing this adjustment is presented in the Annex.

Annual adjustments for inflation

On an annual basis, the revenue requirement will be adjusted in response to changes in the consumer price index. Only the portion of the revenue requirement not indexed to foreign exchange rates will be adjusted for inflation.

These adjustments will be made in the following manner:

$$\begin{aligned} G_Rev_Req' [y] &= \text{Non-forex portion adjusted by inflation} \\ &\quad + \text{Forex portion} \\ &= G_Rev_Req [y] * (1 - G_Forex) * \frac{CPI [y]}{CPI [0]} \\ &\quad + G_Rev_Req [y] * G_Forex \end{aligned}$$

Where $G_Rev_Req [y]$ = annual revenue requirement for year y as determined by ERA at the time of the price review.

$G_Rev_Req' [y]$ = annual revenue requirement for year y adjusted to account for inflation.

$CPI [y]$ = underlying consumer price index¹ at end of year y, as determined from Uganda Bureau of Statistics data.

$CPI [0]$ = underlying consumer price index at time of price review, as determined from Uganda Bureau of Statistics data.

An example of implementing this adjustment is presented in the Annex.

Adjustments for actual investment

ERA will set prices based on expected investment by Genco. Should actual investment differ from expected investment, ERA will take this into consideration at each price review. Any under recovery or over recovery incurred as a result of this deviation will be corrected for in new prices at the 2002 and 2005 price reviews.

¹ The Uganda Bureau of Statistics (www.ubos.org) defines both a headline and an underlying consumer price index. The latter excludes food crops, thus removing the effects of seasonal conditions and is chosen as the appropriate index to use.

Should Genco wish to apply for price adjustments between reviews as a consequence of actual investment being different from expected investment, ERA will consider such applications at the end of each financial year.

2.4 Pricing parameters for 2001 & 2002

The revenue requirement for Genco for 2001 and 2002 is set by ERA as shown in Table 2.1.

Table 2.1 Annual Genco revenue requirement for 2001 and 2002, millions of Ugandan shillings (Ush mill) – Figures are in 2001 prices

Item	2001	2002
Lease fee	-	12 787*
Operating expenses	7 881	7 881
Depreciation	14 883	-
Interest/return	31 318	47**
Taxation	-	20
TOTAL	54 082	20 735
Expected investment	819	405

* Lease fee, set in dollars, is subject to confirmation by Government of Uganda

** Return is subject to the rate bid by the successful concessionaire

The change in cost structure from 2001 to 2002 is a result of the transition to the lease and concession arrangement. Should the Government of Uganda alter the lease fee from the figure given above, ERA will adjust the revenue requirement for 2002 accordingly.

The revenue requirement for 2002 represents a 0% (zero percent) real reduction in operating expenses. From 2003 onwards, ERA will expect real reductions in operating expenses.

Depreciation is calculated at a rate of 2.5%. While the Government of Uganda allows the concessionaire a much higher depreciation rate for tax purposes (50%), ERA will set prices based on the economic life of assets. Since at the start of 2002 the concessionaire will own no assets, there is no depreciation allowance for 2002.

The return for 2002 is based on an after-tax return of 20% on investment. A 15% with-holding tax is also added to this return, so that the return is actually calculated as $20\% * (1+15\%) = 23\%$. This rate is applied to the mid-point between the opening and closing asset values owned by the concessionaire, i.e. $(0 + 405)/2$. The actual rate of return will be set during the concessioning process, and will be adjusted by ERA accordingly.

Taxation is calculated as 30% of the pre-tax return, assuming that all investment is equity financed. At each price review, ERA will examine any windfall losses/profits due to taxation variances and make adjustments to the revenue requirement accordingly.

Other parameters of significance are:

- Exchange rate: 1800 sh/USD
- Forex portion of tariff: 81%

2.5 Indicative pricing parameters for 2003-2005

The table below sets out indicative pricing parameters for Genco for the next price period, i.e. 2003 to 2005. These figures are provisional only. ERA reserves the right to adjust these parameters at the time of the 2002 price review. The lease fee is provisional and will be confirmed by the Government of Uganda.

Table 2.2 Indicative pricing parameters for 2003 - 2005

	2003	2004	2005
Real change in operating costs	-5.0 %	-4.0 %	-3.2 %
Expected investment (USD mill)	1.58	0.90	1.50
Lease fee (USD mill)	7.1	7.1	7.1
Forex portion of tariff	← 81% →		

2.6 Calculation of tariff

Genco will charge Transco a tariff that is calculated from its annual revenue requirement. The tariff will result in monthly charges for capacity made available calculated in the following manner.

Genco will establish the Maximum Actual Capacity (MAC) of each unit by demonstrating the available capacity for each unit at least once per quarter.

For each quarter of the year Genco will calculate a Capacity Price in the following manner:

$$CP [q] = \frac{G_Rev_Req [q]}{\Sigma MAC * Target_Avail * 8760}$$

Where CP [q] = capacity price for quarter q.

G_Rev_Req [q] = annual revenue requirement as determined by ERA at the time of the price review, and adjusted for quarter q (see discussion on adjustments to revenue requirement in section 2.3)

Σ MAC = Sum of Maximum Actual Capacities for all units.

Target_Avail = Target availability as determined by ERA at the time of each price review.

An example of calculating the Capacity Price is presented in the Annex.

For each 24 hour period during which Genco can demonstrate that the Maximum Actual Capacity of a unit is available for the full 24 hours, Genco will calculate a daily charge for this unit in the following manner:

$$\text{Charge [u,d]} = 24 * \text{CP [q]} * \text{MAC}$$

Where Charge [u,d] = Daily charge for unit u on day d

If a unit is on outage or reduced capability (either planned or forced) for any of the 24 hours in question, Genco will calculate a daily charge for this unit in the following manner:

$$\text{Charge [u,d]} = \Sigma (50\% * \text{CP [q]} * \text{Actual_Capacity [h]})$$

Where the summation is over the 24 hours of the day in question and:

Actual_Capacity [h] = actual capacity of the unit during hour h.

Genco will charge a monthly account equal to the sum of all daily charges over the month for all units operated by Genco.

Parameters for 2001 and 2002

ERA has set the target availability (Target_Avail) for these years as:

- 2001 95%
- 2002 95%

Review of tariff calculation method

It should be noted that this method depends on measurement of the actual capacity of each unit for each hour of the day. ERA is of the view that actual measurement may prove difficult. For this reason, this method will be implemented in 2001 and reviewed during the course of 2001. Should significant problems arise with regard to this measurement, ERA reserves the right to design an alternative pricing system.

2.7 Spreadsheet model

A spreadsheet is provided by ERA implementing the adjustments for foreign exchange rates, inflation and the calculation of the capacity price.

3 Bulk supply tariffs

3.1 Introduction

The Transmission Company (Transco) will purchase power from generators and sell this to the distribution company (Disco) and any other customers or distributors connected to the transmission network. Transco will combine the costs of power supply and transmission in a Bulk Supply Tariff (BST).

The power supply element of the BST will be a cost-pass through of Transco's purchases from generation, adjusted for losses and exports. The transmission element of the BST will be regulated by ERA. The approach to regulation is described below.

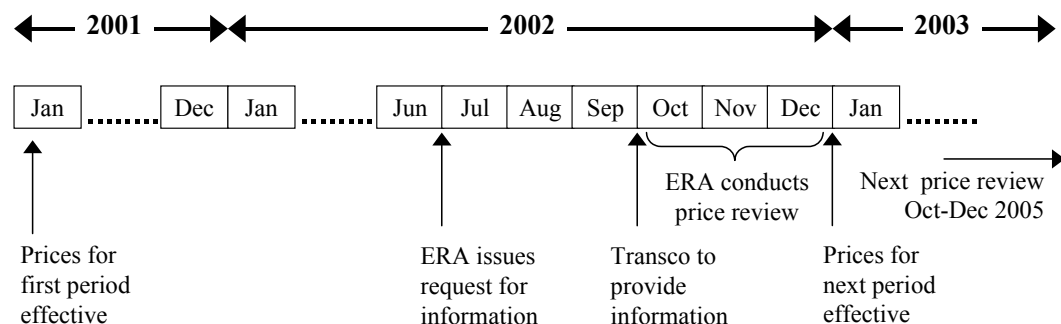
3.2 Timing of price reviews

The revenue requirement of Transco has been set for 2001 and 2002. The revenue requirement will be reset as from 1 January 2003, and thereafter reset every 36 months.

ERA will issue a request for information to Transco six months prior to prices being reset, and such information shall be provided within three months of the request. ERA will determine the scope and format of this information request prior to the call for information.

ERA will conduct a price review over the three month period prior to each resetting of the tariff. This price review will include analysis and verification of information provided by Transco, as well as public hearings conducted by ERA.

Figure 3.1 Illustration of timing of price reviews



3.3 Adjustment of prices between reviews

In between price reviews, ERA authorises Transco to adjust prices according to certain parameters. These parameters relate to foreign exchange rates, inflation, efficiency improvements and investment.

Annual adjustments for efficiency improvements

ERA will set efficiency targets for operating costs at the time of each price review. These will set a target productivity gain for Transco and will be used for price determination. These targets will be built into the annual revenue requirement calculated by ERA.

For 2001 and 2002, ERA has determined the revenue requirement in each year as shown in Table 3.1. This reflects the required operating cost target.

Annual adjustments for foreign exchange rates and inflation

On an annual basis, the revenue requirement will be adjusted in response to changes in the consumer price index and foreign exchange rates.

A portion of the tariff will be designated the “Forex portion”. This portion will be fixed by the ERA at each price review period, and will remain constant until the next review period.

Thus, the portion of the revenue requirement designated Forex portion will be adjusted to reflect changes in exchange rates, and the remaining portion will be adjusted to reflect Ugandan inflation.

Each year, Transco is required to adjust prices according to the following formula:

$$\begin{aligned} T_Rev_Req' [y] &= \text{Forex portion adjusted by new exchange rate} \\ &\quad + \text{Non-forex portion adjusted by inflation} \\ &= T_Rev_Req [y] * T_Forex * \frac{\text{Forex_rate [y]}}{\text{Forex_rate [0]}} \\ &\quad + T_Rev_Req [y] * (1 - T_Forex) * \frac{\text{CPI [y]}}{\text{CPI [0]}} \end{aligned}$$

Where $T_Rev_Req [y]$ = annual revenue requirement for year y as determined by ERA at the time of the price review.

$T_Rev_Req' [y]$ = annual revenue requirement for year y adjusted to account for inflation and changes in foreign exchange rates.

T_Forex = Proportion of tariff indexed to foreign exchange rates, as determined by ERA at each price review.

Forex_rate [y] = shilling to dollar exchange rate at end of year y, as determined from Bank of Uganda statistics.

Forex_rate [0] = shilling to dollar exchange rate as used by ERA at the time of the price review.

CPI [y] = underlying consumer price index² at end of year y, as determined from Uganda Bureau of Statistics data.

CPI [0] = underlying consumer price index at time of price review, as determined from Uganda Bureau of Statistics data.

The annex presents an example of how to do this adjustment.

Adjustments for actual investment

ERA will set prices based on expected investment by Transco. Should actual investment differ from expected investment, ERA will take this into consideration at each price review. Any under recovery or over recovery incurred as a result of this deviation will be corrected for in new prices.

Should Transco wish to apply for price adjustments between reviews as a consequence of actual investment being different from expected investment, ERA will consider such applications at the end of each financial year.

3.4 Pricing parameters for 2001 & 2002

The revenue requirement for Transco for 2001 and 2002 is set by ERA as follows.

Table 3.1 Annual Transco revenue requirement for 2001 and 2002, millions of Ugandan shillings (Ush) – figures are in 2001 prices

Item	2001	2002
Operating expenses	17 482	17 482
Depreciation	7 899	9 362
Interest/return	6 213	6 654*
Taxation	0	0
TOTAL	31 594	33 498
Expected investment**	20 667	24 657

* Depends on debt restructuring at UEB, and may be revised by ERA in the light of this restructuring.

** Takes into account work-in-progress at the start and end of the year

The revenue requirement for 2002 represents a 0% (zero percent) real reduction in operating expenses. From 2003 onwards, ERA will expect real reductions in operating expenses.

² The Uganda Bureau of Statistics (www.ubos.org) defines both a headline and an underlying consumer price index. The latter excludes food crops, thus removing the effects of seasonal conditions and is chosen as the appropriate index to use.

Depreciation is based on a rate of 3.5% per annum, with historical assets revalued in 2001. The return on assets acquired prior to 2001 is taken equal to a proportionate share of UEB's interest payments, and the return for assets acquired thereafter is based on 8% on investment.

Taxation is based on a tax rate of 30%.

Other parameters of significance are:

- Exchange rate: 1800 sh/USD
- Forex portion of tariff: 61%
- Transmission losses: 2001 = 4.8 % 2002 = 4.6 %

For an explanation of how transmission losses affect the BST, see section 0.

3.5 Indicative pricing parameters for 2003-2005

The table below sets out indicative pricing parameters for Transco for the next price period, i.e. 2003 to 2005. These figures are provisional only. ERA reserves the right to adjust these parameters at the time of the 2002 price review.

Table 3.2 Indicative pricing parameters for 2003 - 2005

	2003	2004	2005
Real change in operating costs	-2.5 %	-2.0 %	-1.6 %
Expected investment (USD mill)	30.8	30.8	16.0
Transmission losses	4.4%	4.2%	4.0%
Forex portion of tariff	←————— 77% —————→		

3.6 Calculation of tariff

Transco will charge Disco a tariff that is calculated from its annual revenue requirement and the costs of power purchases from Genco and any other generators. The tariff will be structured as a time-of-use energy charge for peak, shoulder and off-peak periods. The calculation of the tariff will be as follows (an example is presented in the Annex).

Transco will calculate a quarterly cost of service as follows:

$$\text{CoS [q]} = \text{Gen_Payment [q-1]} + \text{T_Rev_Req [q]} \\ + \text{Recon [q-1]} + \text{Export [q-1]}$$

Where CoS [q] = Cost of service for quarter q

Gen_Payment [q-1] = Payment by Transco to generators in quarter q-1

T_Rev_Req [q] = Annual transmission revenue requirement * days in quarter q ÷ 365 (366 in a leap year)

Recon [q-1] = Reconciliation amount equal to the difference between payments to generators in quarter q-1 and receipts from Disco in quarter q-1

Export [q-1] = A share of profits from exports from the previous quarter, as determined by ERA

The BST is then derived from the quarterly cost of service in the following manner.

- Transco will define peak, shoulder and off-peak periods. Transco may update the definition of these periods on an annual basis.
- Transco will measure the output (in MWh) of Genco, any other generator and imports supplying the transmission network and will record the data hourly.
- Similarly, Transco will measure the consumption of export sales and consumption of Disco and record the data at least hourly.

The BST during the shoulder period will then be defined as:

$$\mathbf{BST_sh [q] = \frac{CoS [q]}{MWh_Gen [q-1] * (1 - Trans_Loss)}}$$

Where $BST_sh [q]$ = BST during shoulder period in quarter q

$CoS [q]$ = Cost of service for quarter q

$MWh_Gen [q-1]$ = Output of all generators and imports feeding the transmission system, as measured by Transco in quarter q-1

$Trans_Loss$ = Transmission loss target set by ERA at each price review.

The BST during the peak period will then be defined as:

$$\mathbf{BST_pk [q] = BST_sh [q] * Peak_Factor}$$

Where $BST_pk [q]$ = BST during peak period in quarter q

$Peak_Factor$ = Factor greater than 100% as determined by ERA at each price review.

The BST during the off-peak period will then be defined as:

$$\mathbf{BST_op [q] = \frac{CoS [q] - (BST_sh [q] * LF_sh + BST_pk [q] * LF_pk) * MWh_sold [q-1]}{LF_op * MWh_sold [q-1]}}$$

Where $BST_op [q]$ = BST during off-peak period in quarter q

LF_pk = Proportion of energy consumed during peak period, as determined by ERA at each price review, and updated on request from Transco

LF_sh = Proportion of energy consumed during shoulder period, as determined by ERA at each price review, and updated on request from Transco

LF_op = Proportion of energy consumed during off-peak period, as determined by ERA at each price review, and updated on request from Transco

$MWh_sold [q-1]$ = $MWh_Gen [q-1] * (1 - Trans_Loss)$

Parameters for 2001 and 2002

For 2001 and 2002, the time periods have been set as the following times for each day:

- Off-peak: 23:00 – 05:00
- Shoulder: 05:00 – 18:00
- Peak: 18:00 – 23:00

ERA has set the following parameters used in this algorithm for 2001 and 2002 as follows:

Peak_Factor = 120%
Trans_Loss in 2001 = 4.8%
Trans_Loss in 2002 = 4.6%
LF_pk = 32%
LF_sh = 48%
LF_op = 20%

3.7 Phasing in the costs of Bujagali

When Bujagali power station comes on-line in 2005, costs of supply will increase significantly. The price shock associated with this is unlikely to be acceptable to customers or the distribution company and is viewed with concern by the ERA. Consequently, ERA intends to introduce a new pricing arrangement for the bulk supply tariff so that the costs of Bujagali are phased in over time.

The essence of this arrangement is that bulk supply prices (and hence end-user prices) will increase gradually from their 2001 levels, to a level that incorporates the additional costs of Bujagali by 2008. The Annex to this document sets out the proposed system. ERA is currently developing institutional and financial arrangements to implement this method, which will come into force from 1 January 2002.

3.8 Spreadsheet model

A spreadsheet is provided by ERA demonstrating the adjustments for foreign exchange rates, inflation and the calculation of the BST.

4 End-user tariffs

4.1 Introduction

The distribution company (Disco) will sell power to end-users at a schedule of end-user tariffs. These tariffs will comprise a power supply element and a distribution element.

The power supply element of end-user tariffs will be a pass through of the BST, adjusted for distribution losses. The distribution element of the end-user tariff will be regulated by ERA.

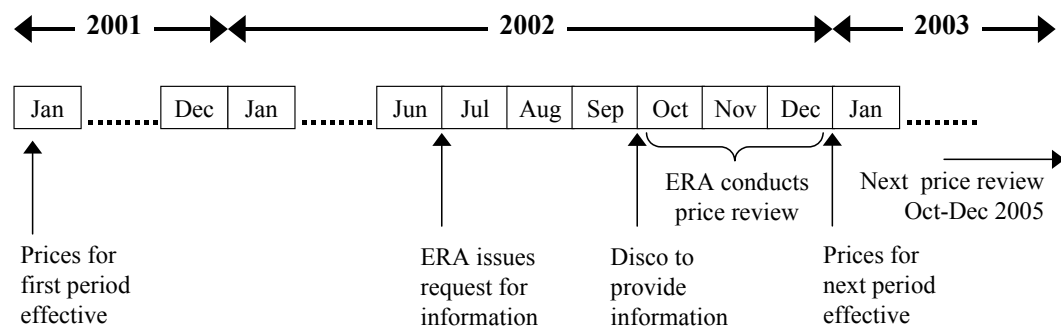
4.2 Timing of price reviews

The revenue requirement of Disco has been set for 2001 and 2002. The revenue requirement will be reset as from 1 January 2003, and thereafter reset every 36 months.

ERA will issue a request for information to Disco six months prior to prices being reset, and such information shall be provided within three months of the request. ERA will determine the scope and format of this information request prior to the call for information.

ERA will conduct a price review over the three month period prior to each resetting of the tariff. This price review will include analysis and verification of information provided by Disco, as well as public hearings conducted by ERA.

Figure 4.1 Illustration of timing of price reviews



4.3 Adjustment of prices between reviews

In between price reviews, ERA authorises Disco to adjust the distribution element of end-user prices according to certain parameters. These parameters relate to foreign exchange rates, inflation, efficiency improvements and investment.

Annual adjustments for efficiency improvements

ERA will set efficiency targets for operating costs at the time of each price review. These will set a target productivity gain for Disco and will be used for price determination. These targets will be built into the annual revenue requirement calculated by ERA.

For 2001 and 2002, ERA has determined the revenue requirement in each year as shown in Table 2.1. This reflects the required operating cost target.

Quarterly adjustments for foreign exchange rates

A portion of the Disco's revenue requirement will be designated the "Forex portion". This portion will be fixed by the ERA at each price review period, and will remain constant until the next review period.

Each quarter (every three months), the portion of the revenue requirement designated the Forex Portion will be adjusted to reflect changes in the exchange rate. This implies that one portion of the revenue require will be adjusted by the new exchange rate, whereas the remaining portion will remain constant.

Consequently, each quarter Disco is required to adjust the revenue requirement according to the following formula:

$$\begin{aligned} \mathbf{D_Rev_Req [q,y]} &= \mathbf{Forex\ portion\ adjusted\ by\ new\ exchange\ rate} \\ &\quad + \mathbf{Non-forex\ portion} \\ &= \mathbf{D_Rev_Req [y] * D_Forex * \frac{Forex_rate [q-1]}{Forex_rate [0]}} \\ &\quad + \mathbf{D_Rev_Req [y] * (1 - D_Forex)} \end{aligned}$$

Where:

$\mathbf{D_Rev_Req [q,y]}$ = annual revenue requirement for Disco used to determine prices in quarter q.

$\mathbf{D_Rev_Req [y]}$ = annual revenue requirement for Disco as determined by ERA at the time of the price review

$\mathbf{D_Forex}$ = Proportion of tariff indexed to foreign exchange rates, as determined by ERA at each price review.

$\mathbf{Forex_rate [q-1]}$ = average shilling to dollar exchange rate in quarter q-1, as determined from Bank of Uganda statistics.

Forex_rate [0] = shilling to dollar exchange rate used by ERA at time of the price review.

An example of implementing this adjustment is presented in the Annex.

Annual adjustments for inflation

On an annual basis, the revenue requirement will be adjusted in response to changes in the consumer price index. Only the portion of the revenue requirement not indexed to foreign exchange rates will be adjusted for inflation.

These adjustments will be made in the following manner:

$$\begin{aligned} \mathbf{D_Rev_Req' [y]} &= \mathbf{Non-forex portion adjusted by inflation} \\ &\quad + \mathbf{Forex portion} \\ &= \mathbf{D_Rev_Req [y] * (1 - D_Forex) * \frac{CPI [y]}{CPI [0]}} \\ &\quad + \mathbf{D_Rev_Req [y] * D_Forex} \end{aligned}$$

Where:

D_Rev_Req [y] = annual revenue requirement for year y as determined by ERA at the time of the price review.

D_Rev_Req' [y] = annual revenue requirement for year y adjusted to account for inflation.

CPI [y] = underlying consumer price index³ at end of year y, as determined from Uganda Bureau of Statistics data.

CPI [0] = underlying consumer price index at the time of the price review, as determined from Uganda Bureau of Statistics data.

An example of implementing this adjustment is presented in the Annex.

Adjustments for actual investment

ERA will set prices based on expected investment by Disco. Should actual investment differ from expected investment, ERA will take this into consideration at each price review. Any under recovery or over recovery incurred as a result of this deviation will be corrected for in new prices at the price reviews of 2002 and 2005.

Should Disco wish to apply for price adjustments between reviews as a consequence of actual investment being different from expected investment, ERA will consider such applications at the end of each financial year.

³ The Uganda Bureau of Statistics (www.ubos.org) defines both a headline and an underlying consumer price index. The latter excludes food crops, thus removing the effects of seasonal conditions and is chosen as the appropriate index to use.

4.4 Pricing parameters for 2001 & 2002

The revenue requirement for Disco for 2001 and 2002 is set by ERA as follows.

Table 4.1 Annual Disco revenue requirement for 2001 and 2002, millions of Ugandan shillings (Ush) – figures are in 2001 prices

Item	2001	2002
Lease fee	-	42 051*
Operating expenses	29 209	29 209
Depreciation	15 783	-
Interest/return	13 202	11 519**
Bad debt expense	10 272	10 793
Taxation	-	4 937
TOTAL	68 466	98 059
Expected investment***	46 156	28 813

* Lease fee depends on confirmation by the Government of Uganda.

** Return depends on rate of return bid by successful concessionaire.

*** Takes account of work in progress at beginning and end of the year

The change in cost structure from 2001 to 2002 is a result of the transition to the lease and concession arrangement. Should the Government of Uganda alter the lease fee from the figure given above, ERA will adjust the revenue requirement for 2002 accordingly.

The revenue requirement for 2002 represents a 0% (zero percent) real reduction in operating expenses. From 2003 onwards, ERA will expect real reductions in operating expenses.

Depreciation is calculated at a rate of 3.5%. While the Government of Uganda allows the concessionaire a much higher depreciation rate for tax purposes (50%), ERA will set prices based on the economic life of assets. Since at the start of 2002 the concessionaire will own no assets, there is no depreciation allowance for 2002.

The return for 2002 is based on an after-tax return of 20% on investment. A 15% with-holding tax is also added to this return, so that the return is actually calculated as $20\% * (1+15\%) = 23\%$. This rate is applied to the mid-point between the opening and closing asset values owned by the concessionaire, i.e. $(0 + 14203)/2$ mill Ush, plus the same return on working capital. Working capital is taken equal to 30 days arrears, plus arrears purchased on 1 January 2002 (estimated at 17400 mill Ush). The actual rate of return will be set during the concessioning process, and will be adjusted by ERA accordingly.

Bad debt expenses are calculated as 3.42 % of estimated turn-over in 2001 and 3.34 % in 2002. Taxation is calculated as 30% of the pre-tax return.

Other parameters of significance are:

- Exchange rate: 1800 sh/USD
- Forex portion of tariff: 66%

4.5 Indicative pricing parameters for 2003-2005

The table below sets out indicative pricing parameters for Disco for the next price period, i.e. 2003 to 2005. These figures are provisional only. ERA reserves the right to adjust these parameters at the time of the 2002 price review. The lease fee is provisional and will be confirmed by the Government of Uganda.

Table 4.2 Indicative pricing parameters for 2003 - 2005

	2003	2004	2005
Real change in operating costs *	-5.0 %	-4.0 %	-3.2 %
Expected investment (USD mill)	18.5	12.5	28.7
Expected lease fee (USD mill)	1.25	1.25	1.25
Bad-debt expense	3.25%	3.17%	3.08%
Arrears	30 days	30 days	30 days
Forex portion of tariff	71%	74%	78%

* ERA may adjust this real reduction in operating expenses to take account of growth in the number of customers.

4.6 Calculation of end-user tariffs

End-user tariffs will be comprise of three elements:

- A power supply element to reflect the costs of power purchased from Transco, adjusted for losses
- A distribution element to reflect Disco's revenue requirement
- Lifeline charge to cover the costs of a lifeline charge to small customers (Code 10).

Power supply element

The power supply element of end-user tariffs will be charged as shillings per kWh consumed.

The power supply element of end-user tariffs for a particular tariff category should be calculated as follows (an example is presented in the annex):

$$PS [c,q] = \frac{BST_pk [q] * LF_pk [c] + BST_sh [q] * LF_sh [c] + BST_op [q] * LF_op [c]}{1 - Tech_Loss [c] - Nontech_Loss [c]}$$

Where PS [c,q] = Power supply element of end-user tariff to customer class c in quarter q.

BST_pk [q] = Bulk Supply Tariff during peak period in quarter q

BST_sh [q] = Bulk Supply Tariff during shoulder period in quarter q

BST_op [q] = Bulk Supply Tariff during off-peak period in quarter q

LF_pk [c] = Proportion of energy consumed by customer class c during peak period

LF_sh [c] = Proportion of energy consumed by customer class c during shoulder period

LF_op [c] = Proportion of energy consumed by customer class c during off-peak period

Tech_Loss [c] = Technical losses in supplying customer class c.

Nontech_Loss [c] = Non-technical losses in supplying customer class c, as determined by ERA

Parameters for 2001 and 2002

The customer classes chosen for 2001/2 are:

- Code 10: General customers on LV networks
- Code 20: Industrial customers on LV networks
- Code 30: Customers on MV networks
- Code 50: Streetlights

ERA has set the following loss parameters for these years as shown in Table 4.3

Table 4.3 Loss figures allowed by ERA for 2001 and 2002

	2001	2002
Total technical losses	14.0%	12.0%
Total non-technical losses	19.0%	17.0%

The Disco is permitted to allocate these different losses to different customer classes at its own discretion, and to inform ERA of this allocation. The allocation approved by ERA for the 2001 and 2002 prices are given in Table 4.4.

Table 4.4 Allocation of losses to customer classes for 2001 & 2002 prices

	2001		2002	
	Technical loss	Non-tech loss	Technical loss	Non-tech loss
Code 10	16.7 %	23.5 %	14.2 %	20.9 %
Code 20	16.7 %	23.5 %	14.2 %	20.9 %
Code 30	5.1 %	4.1 %	4.5 %	4.0 %
Code 50	16.7 %	23.5 %	14.2 %	20.9 %
Weighted average	14.0 %	19.0 %	12.0 %	17.0 %

Load profile information for each customer class is to be estimated by Disco and submitted to ERA when each new estimate is made. The figures approved by ERA for the 2001 tariff application are shown in Table 4.5

Table 4.5 Load profile information used in 2001 tariffs

	LF_pk	LF_sh	LF_op	Power supply charge (Ush/kWh)		
Code 10	38%	56%	6%	103.6		
Code 20	38%	56%	6%	103.6		
Code 22	0%	0%	100%	72.5		
Code 30	35%	65%	0%	68.9		
Code 32	0%	0%	100%	47.7		
Code 50	60%	0%	40%	99.4		
Code 60*	10%	19%	71%	77.2	64.4	47.7

* With peak, shoulder and off-peak energy prices

Application of this method using estimates of the Bulk Supply Tariff (actual results will depend on exchange rates and generation station availabilities) results in the charges shown in Table 4.5.

Distribution and lifeline elements

Disco shall charge its revenue requirement as set by ERA to end-users through a schedule of distribution tariffs.

ERA will allow Disco the freedom to structure these distribution charges, subject to the proviso that the methodology used to allocate costs should be seen to be cost-reflective. Disco should submit its methodology and results to ERA on an annual basis.

ERA has determined that a lifeline tariff should be offered for 2001, but that this tariff will be phased out over time. The lifeline tariff is to offer all Code 10 customers the first 30 kWh per month at a concessional rate of 50 Ush/kWh. The costs of this tariff are to be spread over all other customers through a special lifeline charge.

ERA has set distribution prices for 2001 as follows. With the exception of the lifeline charge, this calculation is undertaken with no cross-subsidies between user groups:

Table 4.6 End-user charges for 2001

Tariff code	Power supply charge	Fixed monthly fee	Maximum demand		Distribution charge	Lifeline charge
	Ush/kWh	Ush/mth	Up to 2 MVA Ush/kVA	Above 2 MVA 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

Annex A: Examples of price adjustment calculations

A.1 Generation price calculations

The generation revenue requirement is to be adjusted quarterly for foreign exchange movements, and annually for inflation. The examples below show how this is calculated.

Adjustments for foreign exchange rates

The annual revenue requirement for generation in 2001 is 54,082 million Ush. This has been calculated at an exchange rate of 1800 Ush/\$, and the proportion designated foreign exchange is 87%.

Once a quarter this revenue requirement is to be updated to reflect changes in exchange rates. Suppose the average exchange rate for Quarter 1 was 1850 Ush/\$, then the adjusted revenue requirement for Quarter 2 will be:

$$\begin{aligned} G_Rev_Req [2, 2001] &= G_Rev_Req [y] * G_Forex * \frac{Forex_rate [q-1]}{Forex_rate [0]} \\ &\quad + G_Rev_Req [y] * (1 - G_Forex) \\ &= 54,082 * 87\% * 1850/1800 + 54,082 * (1-87\%) \\ &= 48,358 + 7,030 = 55,388 \text{ mill Ush} \end{aligned}$$

Annual adjustments for inflation

The revenue requirement for 2002 (in 2001 terms) is 51,662 mill Ushs. At the start of 2002, this revenue requirement is to be updated for inflation. Suppose the annual underlying inflation for 2001 was 4.5%, then the adjustment will be:

$$\begin{aligned} G_Rev_Req' [2002] &= G_Rev_Req [2002] * (1 - G_Forex) * \frac{CPI [2002]}{CPI [0]} \\ &\quad + G_Rev_Req [2002] * G_Forex \\ &= 51,662 * (1-87\%) * (104.5/100) + 51,662 * 87\% \end{aligned}$$

$$= 7,018 + 44,945 = 51,963 \text{ mill Ush}$$

Naturally, this revenue requirement in the first quarter of 2002 must also be adjusted for the exchange rate of the previous quarter. Suppose that the average exchange rate for the last quarter of 2001 was 1900 Ush/\$, then the revenue requirement for the first quarter of 2002 will be calculated as follows:

$$\begin{aligned} G_Rev_Req' [1, 2002] &= G_Rev_Req' [2002] * G_Forex * \frac{Forex_rate [4]}{Forex_rate [0]} \\ &\quad + G_Rev_Req' [2002] * (1 - G_Forex) \\ &= 51,963 * 87\% * 1900/1800 + 51,963 * (1-87\%) \\ &= 47,719 + 6,755 = 54,474 \text{ mill Ush} \end{aligned}$$

Calculation of capacity price

The Capacity Price is calculated as a function of the revenue requirement, the maximum available capacity and the target availability. This last parameter is set at 95.3%.

Suppose that the maximum available capacity in the first quarter of 2001 was shown to be 232 MW. We have already shown that the revenue requirement to use in the second quarter is 55,388 mill Ush and so for the second quarter of 2001, the Capacity Price would be calculated as

$$\begin{aligned} CP [2] &= \frac{G_Rev_Req [2]}{\Sigma MAC * Target_Avail * 8760} \\ &= 55,388 * 10^6 \text{ Ush} / (232 * 95.3\% * 8760) \\ &= 28,598 \text{ Ush/MW} \end{aligned}$$

A.2 Transmission price calculations

The transmission revenue requirement is to be adjusted for foreign exchange movements and inflation, both on an annual basis. The example below show how this is calculated.

Annual adjustments for foreign exchange rates and inflation

The annual Transmission revenue requirement for 2002 is 33,498 mill Ush and the foreign exchange portion is 58%. At the start of 2002, this parameter is to be adjusted for inflation and foreign exchange changes. As above, suppose the average exchange rate for the last quarter of 2001 is 1900, compared with the 1800 originally used in the price calculation. In addition, suppose the inflation for 2001 to be 4.5%.

$$\begin{aligned} T_Rev_Req' [2002] &= T_Rev_Req [2002] * T_Forex * \frac{Forex_rate [2001]}{Forex_rate [0]} \\ &\quad + T_Rev_Req [y] * (1 - T_Forex) * \frac{CPI [2002]}{CPI [2001]} \end{aligned}$$

CPI [0]

$$\begin{aligned}
 &= 33,498 * 58\% * 1900 / 1800 \\
 &\quad + 33,498 * (1-58\%) * 104.5 / 100 \\
 &= 20,508 + 14,702 = 35,210 \text{ mill Ush}
 \end{aligned}$$

Calculation of BST

The BST is calculated on a quarterly basis to reflect changes in the Capacity Price, energy generated in the previous quarter and any reconciliation due to actual consumption in the previous quarter being different from that used to calculate the tariff.

The first step is to calculate the Cost of Service for the quarter. For the second quarter for 2002, the following information is required to do this:

- Payment to generation in quarter 1 = 13,614 mill Ush
- Transmission rev requirement in quarter 2 = $31,594 * 91/365 = 7,877$ m Ush
- Reconciliation = difference between money paid to generator in quarter 1 and revenue collected in quarter 1 = 301 mill Ush
- Share of export profit = 0

Then the cost of service for quarter 2 is given by:

$$\begin{aligned}
 \text{CoS [2]} &= \text{Gen_Payment [1]} + \text{T_Rev_Req [2]} \\
 &\quad + \text{Recon [1]} + \text{Export [1]} \\
 &= 13,614 + 7,877 + 301 + 0 = 21,792 \text{ mill Ush}
 \end{aligned}$$

Supposing that in quarter 1, the total amount of energy purchased by Transco was 380 GWh. Also, note that the Transmission Loss target is 4.8%.

Then the BST in the shoulder period for quarter 2 is calculated as follows:

$$\begin{aligned}
 \text{BST_sh [2]} &= \frac{\text{CoS [2]}}{\text{MWh_Gen [1]} * (1 - \text{Trans_Loss})} \\
 &= 21,792 / (380 * (1-4.8\%)) = 60.2 \text{ Ush/kWh}
 \end{aligned}$$

The BST during the peak period will then be calculated as:

$$\begin{aligned}
 \text{BST_pk [2]} &= \text{BST_sh [q]} * \text{Peak_Factor} \\
 &= 60.2 * 120\% = 72.2 \text{ Ush/kWh}
 \end{aligned}$$

Noting that the load profile for bulk supply is 32% in the peak, 48% in the shoulder period, and 20% in the off-peak period. Further, the energy sold in quarter 1 is given by:

$$\begin{aligned}
 \text{MWh_sold [1]} &= \text{MWh_Gen [1]} * (1 - \text{Trans_Loss}) \\
 &= 380 * (1-4.8\%) = 361.7 \text{ GWh.}
 \end{aligned}$$

The BST during the off-peak period will then be calculated as:

$$\begin{aligned}
 \text{BST}_{\text{op}} [2] &= \frac{\text{CoS} [2] - (\text{BST}_{\text{sh}} [2] * \text{LF}_{\text{sh}} + \text{BST}_{\text{pk}} [2] * \text{LF}_{\text{pk}}) * \text{MWh}_{\text{sold}} [1]}{\text{LF}_{\text{op}} * \text{MWh}_{\text{sold}} [1]} \\
 &= [21,792 - (60.2 * 48\% + 72.2 * 32\%) * 361.7] / (20\% * 361.7) \\
 &= [21,792 - (52.0) * 361.7] / (20\% * 361.7) \\
 &= [2\ 984] / (20\% * 361.7) = 41.2 \text{ Ush/kWh}
 \end{aligned}$$

A.3 Distribution price calculations

The generation revenue requirement is to be adjusted quarterly for foreign exchange movements, and annually for inflation. The examples below show how this is calculated.

Adjustments for foreign exchange rates

The annual revenue requirement for generation in 2001 is 68,466 million Ush. This has been calculated at an exchange rate of 1800 Ush/\$, and the proportion designated foreign exchange is 55%.

Once a quarter this revenue requirement is to be updated to reflect changes in exchange rates. Suppose the average exchange rate for Quarter 1 was 1850 Ush/\$, then the adjusted revenue requirement for Quarter 2 will be:

$$\begin{aligned}
 \text{D_Rev_Req} [2, 2001] &= \text{D_Rev_Req} [y] * \text{D_Forex} * \frac{\text{Forex_rate} [q-1]}{\text{Forex_rate} [0]} \\
 &\quad + \text{D_Rev_Req} [y] * (1 - \text{D_Forex}) \\
 &= 68,466 * 55\% * 1850/1800 + 68,466 * (1-55\%) \\
 &= 38,702 + 30,810 = 69,512 \text{ mill Ush}
 \end{aligned}$$

Annual adjustments for inflation

The revenue requirement for 2002 (in 2001 terms) is 98,059 mill Ushs. At the start of 2002, this revenue requirement is to be updated for inflation. Suppose the annual underlying inflation for 2001 was 4.5%, then the adjustment will be:

$$\begin{aligned}
 \text{D_Rev_Req}' [2002] &= \text{D_Rev_Req} [2002] * (1 - \text{D_Forex}) * \frac{\text{CPI} [2002]}{\text{CPI} [0]} \\
 &\quad + \text{D_Rev_Req} [2002] * \text{D_Forex} \\
 &= 98,059 * (1-55\%) * (104.5/100) + 98,059 * 55\% \\
 &= 46,112 + 53,932 = 100,044 \text{ mill Ush}
 \end{aligned}$$

Naturally, this revenue requirement in the first quarter of 2002 must also be adjusted for the exchange rate of the previous quarter. Suppose that the average

exchange rate for the last quarter of 2001 was 1900 Ush/\$, then the revenue requirement for the first quarter of 2002 will be calculated as follows:

$$\begin{aligned}
 D_Rev_Req' [1, 2002] &= D_Rev_Req' [2002] * D_Forex * \frac{Forex_rate [4]}{Forex_rate [0]} \\
 &\quad + D_Rev_Req' [2002] * (1 - D_Forex) \\
 &= 100,044 * 55\% * 1900/1800 + 100,044 * (1-55\%) \\
 &= 58,081 + 45,020 = 103,101 \text{ mill Ush}
 \end{aligned}$$

Calculating the power supply element of end-user tariffs

As an example of calculating the power supply element of an end-user tariff, we look at the power supply charge to customer code 10 in quarter 2 of 2001.

In this quarter we have calculated the BST (see above) as 72.2, 60.2 and 41.2 Ush/kWh in peak, shoulder and off-peak periods respectively.

For Code 10, the allowances for technical losses are 16.7% and for non-technical are 23.5%. In addition, the load profile information for Code 10 is 38% in peak, 56% in shoulder and 6% in off-peak.

We can then calculate the Power Supply charge to Code 10 in quarter 2 as follows:

$$\begin{aligned}
 PS [10,2] &= \frac{BST_pk [2] * LF_pk [10] + BST_sh [2] * LF_sh [10] + BST_op [2] * LF_op [10]}{1 - Tech_Loss [10] - Nontech_Loss [10]} \\
 &= [72.2 * 38\% + 60.2 * 56\% + 41.2 * 6\%] / (1 - 16.7\% - 23.5\%) \\
 &= [27.4 + 33.7 + 2.5] / 0.598 = 105.4 \text{ Ush/kWh}
 \end{aligned}$$

Annex B:

Revised bulk supply tariff

Costs of supplying electricity in Uganda will increase dramatically in 2005. At the moment almost all electricity supplied in Uganda is sourced from the two power stations at the mouth of the Nile River – Kiira and Nalubaale power stations. The unit costs of electricity from these stations is low – in the order of 50 Ush/kWh, or 2.8 Usc/kWh.

Despite the recent and planned extension of capacity at these plants, Uganda will remain capacity constrained, and the problem will only exacerbate as demand continues to grow. The planned station at Bujagali Falls will be commissioned in 2005, introducing an additional 200 MW of capacity – almost doubling supply capacity. While this will relieve capacity constraints for several years to come, the costs of supply will increase significantly. The power sales agreement with Bujagali implies payments of around \$100 million per annum, effectively on a take-or-pay basis. Even without taking into account currency devaluation, this will more than triple overall costs of power generation (total costs at Kiira and Nalubaale amount to approximately \$36 million per annum).

Since costs are transferred to end-users in prices, the effect on tariffs will be dramatic. The price effect is accentuated by the likely presence of surplus capacity in the years following the commissioning of Bujagali in 2005. As this surplus capacity is eroded by demand growth, so unit costs can be expected to decline somewhat.

The ERA has an interest to improve price stability. One way of achieving this is to gradually increase the price increase attributable to the additional costs of Bujagali prior to 2005. This will mean that a surplus will be made over the period 2002 to 2004 and this can be used to buy down the cost of power during the period of surplus capacity. From 2008 onwards, prices can then be set at their cost-reflective level.

ERA has proposed the approach detailed below. While there is acceptance of the basic principles, on-going investigations by ERA are exploring the implementation of this mechanism.

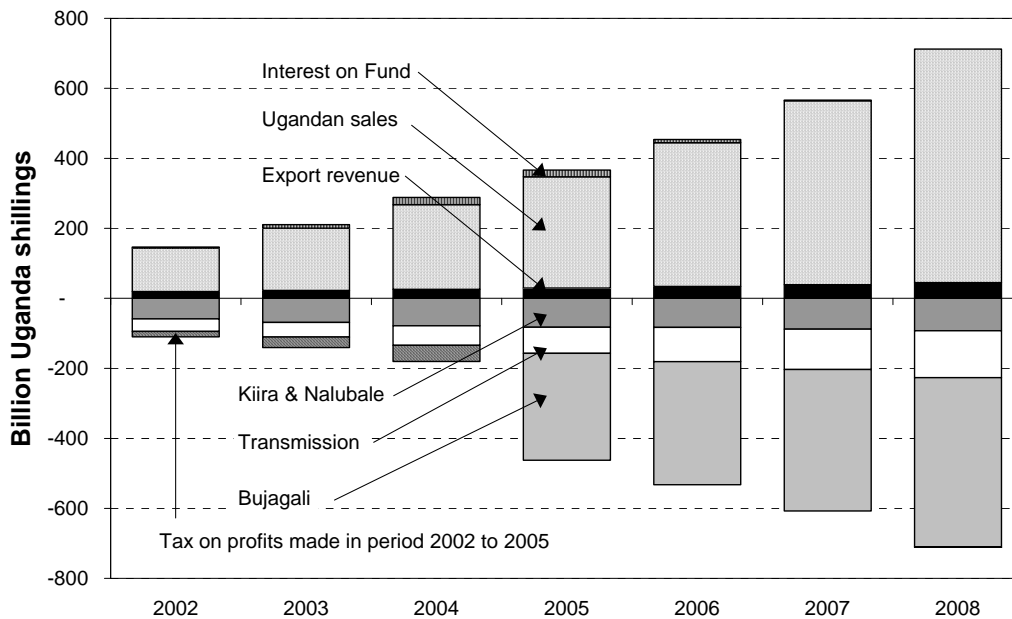
B.1 Pricing mechanism

The Bulk Supply Tariff charged by the Transmission Company will be used to implement this price adjustment mechanism. The concept is that:

- Price increases commence in 2002 and gradually increase to cost-reflective levels by 2008
- Surpluses made in the period 2002 to 2004 are placed in a Fund operated by the Transmission Company and used to buy-down the costs of supply in the period 2005 to 2007.

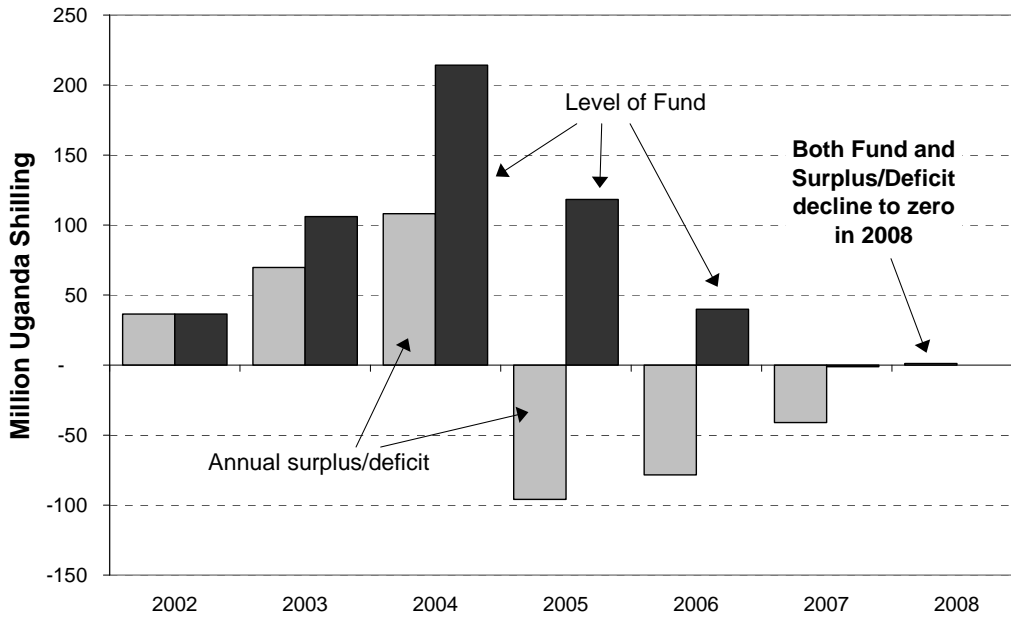
The pricing mechanism can be balanced so that the Fund is fully utilised by 2008. This mechanism is illustrated in the figure below which shows costs and revenue. In this illustration, prices are set so that revenue from Ugandan sales in 2008 and exports equals the costs of supply in that year.

Figure B.1 Costs and revenue of bulk supply



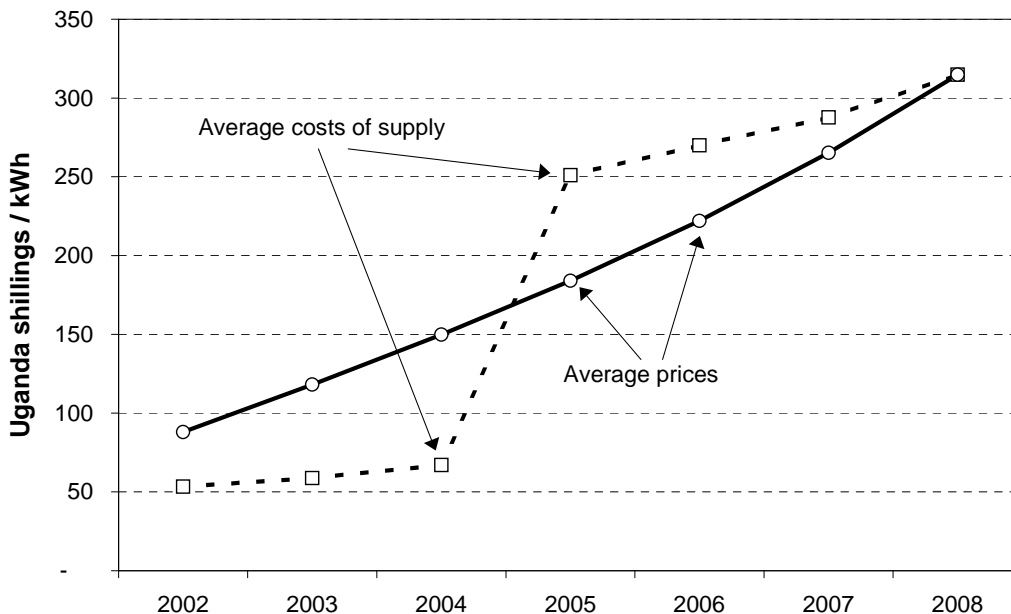
Surplus revenues are made in the period 2002 to 2004, and these are used to build up a Fund, which is then used to finance deficits in the years 2005 to 2007. The annual surpluses and the level of the Fund in the example illustrated above are shown in the figure below. The pricing mechanism is designed so that both annual surplus/deficit and the Fund decline to zero in 2008. At this point prices are set to cost reflective levels and no surpluses or deficits are realised.

Figure B.2 Annual surpluses and accumulation in Fund



As this method implies, prices will be above costs in the period 2002 to 2004, and below costs in the period 2005 to 2007. In 2008, prices will reflect costs. The figure below illustrates this effect, and shows how the mechanism smoothes in price increases over time. In this illustration, prices increase quite steeply each year, and this is because an annual 15% devaluation in the currency is assumed each year. Since the Bujagali contract, and many elements of the costs at Kiira and Nalubaale, are in US dollars, this devaluation has a fairly dramatic effect on prices, leading to prices in 2008 that are more than five times their level in 2001 (58 shillings/kWh). Nevertheless, as can be seen the proposed mechanism leads to smoother prices than would otherwise be obtained.

Figure B.3 Comparison of average costs of supply and average prices



B.2 Implementing the method

The objective of the method is to result in prices in 2008 that are cost reflective. However, at this stage we can only estimate costs in 2008 and this estimate may not be very accurate. Costs of supply in 2008 will depend on several factors:

- Foreign exchange rates
- Inflation
- Investment in transmission as well as Kiira and Nalubaale
- Efficiency targets set by ERA at the next price review in 2005

Costs are especially sensitive to changes in foreign exchange rates, which is also the most uncertain of the above variables. Consequently, it is not possible to set prices now for the full period until 2008. Instead, prices can be set on an annual basis, based on updated cost projections.

The spreadsheet pricing model

ERA has designed a spreadsheet to implement this proposed method, which allows the ERA to update variables on an annual basis, perform the price setting calculations and obtain updated Bulk Supply Tariffs. The same spreadsheet tool can be used to update prices on a quarterly or regular basis in response to exchange rate variations.

The data that should be updated on an annual basis comprises:

- Exchange rate for previous year and exchange rate projections
- Interest rate for previous year and interest rate projections
- Power purchases for previous year and projections of power purchases
- Exports for previous year and export projections
- Average export price for previous year and price projections
- Load profile of sale to Disco (% in peak, shoulder and off-peak)
- Costs of transmission and generation for previous year and projections
- Previous year's Bulk Supply Tariff if different from that in the model

The spreadsheet is provided together with this report.

Export revenue

The method requires that that all export revenue is used to off-set prices in Uganda.

Taxation

The method assumes that annual trading profits, together with interest on the Fund, will be taxed at 30%. This naturally implies higher prices than would otherwise result. Should the Ministry of Finance provide a waiver on taxation of profits accrued to the Fund, then this can easily be implemented in the model by setting the tax level to zero percent. This will result is approximately 20% lower prices over the period. The ERA will investigate the taxation implications.

Price structure

The method implements a price structure as proposed for 2001, that is the Bulk Supply Tariff is a time-or-use energy charge, with peak, shoulder and off-peak prices. The ratio between prices in each period is kept constant at 120:100:74. Alternative price structures include the option of a maximum demand charge as well as different price ratios between price periods.