

**Report 26/01**

# **End - user consequences of generation contracts**

# End - user consequences of generation contracts

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

# Table of Contents:

LIST OF ABBREVIATIONS.....	
EXECUTIVE SUMMARY .....	1
1 INTRODUCTION.....	5
1.1 Background.....	5
1.2 Generation price structure.....	6
1.3 Regulation of generation prices .....	6
2 GENERATION COST STRUCTURE.....	8
2.1 Data sources .....	8
2.2 Elements of the cost structure .....	9
2.3 Base case results .....	11
2.4 Key sensitivities .....	17
3 RISK TRANSFER .....	19
3.1 Introduction.....	19
3.2 Risks and the transfer of risk .....	20
3.3 Summary .....	24
4 ALTERNATIVE RISK TRANSFER ARRANGEMENTS.....	26
4.1 Contractual arrangements .....	26
4.2 Price structures.....	28
4.3 Price adjustment mechanisms .....	28
4.4 Risk premium.....	29
5 CONCLUSIONS .....	31
5.1 Cost structure .....	31
5.2 Risk transfer .....	32
ANNEX A: SENSITIVITY ANALYSIS .....	34
A1 Ugandan inflation.....	34
A2 Currency devaluation .....	35
A3 Changes in lease fee.....	36
A4 Return on Genco's investments .....	39
A5 Hydro discharge .....	40
A6 Ugandan demand .....	40
ANNEX B: UGANDAN INFLATION AND DEVALUATION TRENDS .....	43

## List of abbreviations

BST	Bulk supply tariff
Disco	Distribution company
ERA	Electricity Regulatory Authority
Genco	Generation company
NVE	Norwegian Energy and Water Resources Directorate
Transco	Transmission company
UEB	Uganda Electricity Board
UGX	Ugandan Shillings
URU	Utility Reform Unit
USD	US Dollars

# Executive Summary

## Abstract

*We have examined the cost structure of generation at Nalubaale and Kiira power stations, and analysed the transfer of risks in the proposed contractual arrangements and price regulations. In addition, we have briefly examined alternative arrangements that would change the way risks are dealt with in the industry.*

## Background

The Electricity Regulatory Agency (ERA) has a co-operation agreement with the Norwegian Energy and Water Resources Directorate (NVE). Under this co-operation, ECON Centre for Economic Analysis has been contracted to assist with special pricing studies for the Ugandan electricity sector. An initial report, *Cost Structure and Tariff Study for Uganda*, was submitted in February 2001. ECON was subsequently requested to extend this work in a number of areas. One such area was further analysis of the cost structure and pricing of power from existing generation assets – Nalubaale and Kiira power stations. This report sets out our findings from this analysis.

Nalubaale and Kiira power stations on the Nile River are currently owned and operated by the Ugandan Electricity Board (UEB) – a state-owned enterprise. In the course of 2001, these assets will be separated from UEB's network assets and operations in a separate subsidiary company – UEB Generation. From 2002, these assets are to be leased to the private sector through a concession arrangement.

Our analysis focuses on the proposed generation pricing contract and associated risk allocation under the proposed regulatory framework. In addition, we have briefly examined some alternative arrangements that would change the way risks are dealt with in the industry.

## Conclusions

### *Generation costs*

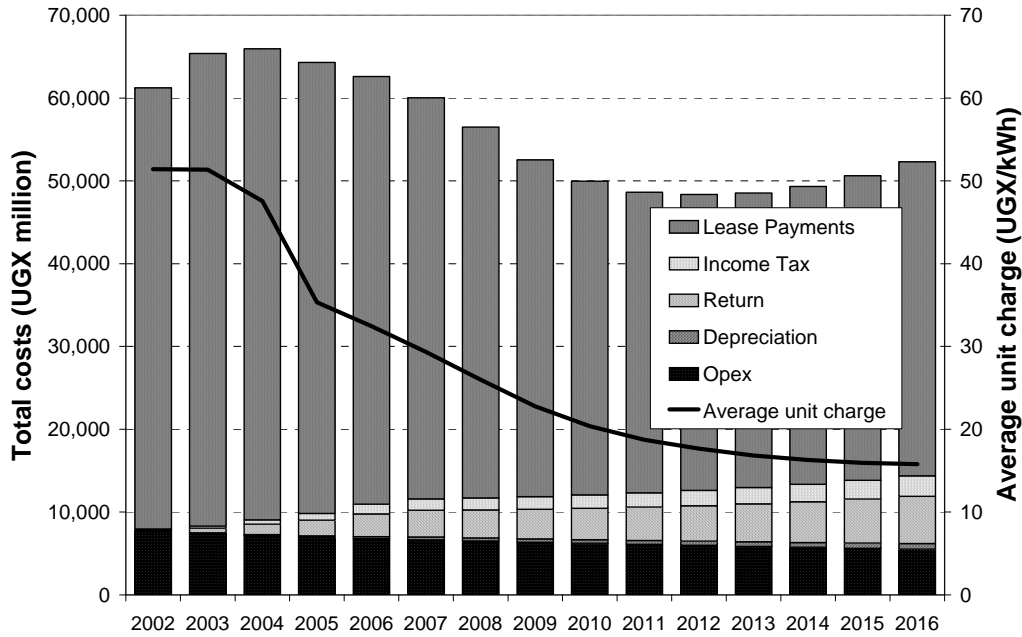
From the start of the concession period in 2002, the revenue requirement of Nalubaale and Kiira will be comprised of:

- a lease fee paid to UEB Generation,
- operating costs at the plants themselves,
- depreciation of assets owned by Genco, and

- a return allowance and taxation.

The lease fee makes up approximately 80 percent of all costs, and is itself comprised of depreciation of assets owned by UEB Generation, interest payments on UEB Generation debt and a small administration fee. The cost structure is illustrated in Figure 1.1, which also shows the average unit charge, i.e. the ratio of costs to total electricity sales

*Figure 1.1 Cost structure of generation at Nalubaale and Kiira (base case assumptions, real terms)*



The total costs at Nalubaale and Kiira will be approximately UGX 65 billion in the first few years of the concession. This declines over the first five years and levels out at approximately UGX 50 billion in the second half of the concession period. As an element of consumer tariffs, the decline is more marked due to consumption growth – the average charge to customers for power from these assets starts at around 50 UGX/kWh and declines by approximately 60 percent by 2016.

Costs are very sensitive to devaluation of the currency as the main portion of costs is denominated in US dollars. The base case has assumed an annual devaluation of 14.5 percent - consistent with trends over the past three years. If devaluation is significantly different from this, the cumulative impact on generation costs at Nalubaale and Kiira will be large.

Other significant cost sensitivities relate to the lease fee and inflation. Since a large portion of the lease fee is made up of interest payments on UEB Generation’s debt, the proposed capital restructuring of UEB Generation will have a significant impact on costs. We have shown that reducing the interest payments by 50 percent will reduce costs by an average of 19 percent over the period. The effect will be particularly strong in the early years of the concession.

It is noteworthy that the costs are not particularly sensitive to Genco's rate of return. This is because new investment is expected to be small in relation to total assets, and so Genco's return makes up less than 10 percent of the total costs.

*Risk transfer*

Risk transfer is embodied in the contractual arrangements and price mechanisms. The proposed system comprises a concession (lease of assets with the responsibility for new investment), a capacity price for capacity made available, and periodic adjustments for exchange rates, inflation and investment.

The main risks present in the business relate to:

- investment risk,
- foreign exchange rates,
- inflation,
- operating costs,
- plant availability,
- domestic sales,
- export volumes and prices,
- transmission outages, and
- political risks (in relation to policy on the lease fee).

Of these risks, the most significant are those relating to foreign exchange, the lease fee, inflation and exports.

All risks except those relating to operating costs, availability, network outages and export price are transferred to consumers, as shown in Figure 1.2. Risks relating to operating costs and availability remain with Genco, and Transco bears risks relating to export price (and network outages, if there are appropriate provisions in contracts between Transco and Disco). It should be noted that Transco's incentives relating to exports are not aligned with those of consumers. The latter benefit from exports at any price, whereas Transco only benefits if export prices are above a certain level.

*Figure 1.2 Representation of risk transfer*

<b>Risk</b>	<b>Genco</b>	<b>Transco</b>	<b>Disco</b>	<b>Customer</b>	<b>Mechanism</b>
Investment	$\lambda$			$\lambda$	Revision of asset base
Inflation				$\lambda$	Price adjustments
Currency				$\lambda$	Price adjustments
Opex	$\lambda$				Allowance in revenue req.
Availability	$\lambda$				Capacity price formula
Exports				$\lambda$	Capacity price formula
Uganda volume				$\lambda$	Capacity price formula
Lease fee				$\lambda$	Allowance in revenue req.
Network outage		$\lambda$			Transco-Disco contract

Alternative risk transfer arrangements can be embodied in different contractual arrangements, price structures and adjustment mechanisms.

The principal alternative contractual arrangements are a management contract and asset privatisation. A management contract would be very similar to the current arrangements, with the only significant difference relating to the source and cost of capital for new investment. Since new investment is relatively minor, this will not have a large impact on prices. Privatisation would have the effect of expressing many of the risks in the privatisation price. As a result, the costs of risk would largely be borne by the Government rather than consumers. Such an arrangement would allow Government to allocate more risks to Genco than under the current arrangement without leading to significantly higher prices. It may mean, however, that privatisation revenues do not match UEB's existing debt obligations.

The current price structure is essentially a take-or-pay arrangement, independent of actual volume of power or energy delivered. The alternative would be a unit price based on maximum demand, energy or a combination. This would impose volume risk on Genco, as in fact occurs with the distribution company. There are two difficulties with such a system. Firstly, since the lease fee makes up such a large portion of costs, the volume risk would be large and difficult to compensate through an increased rate of return. Such a pricing system would have to be accompanied by the lease fee also being structured as a unit charge. Secondly, there would be a conflict from 2005 once Bujagali comes on line. Since Bujagali is a take-or-pay contract, Transco would prefer to take power from Bujagali rather than pay a marginal price to Genco. Given the excess capacity from 2005, the volume risk for Genco at this time would be extremely high.

Finally, the price adjustment mechanism transfers risks related to foreign exchange, inflation and investment. The current system transfers 100 percent of all these risks, with a proposed change in the way investment risks are handled from 2005. Alternative systems, such as use of a reduced adjustment factor, a sliding scale or an adjustment band, would share risks between Genco and consumers. Such an approach could be used in conjunction with asset privatisation, and would allocate the costs of risks among the Government (via the privatisation price), investors (through their expose to a portion of risks) and consumers (through the risks that are transferred by the adjustment mechanism).

# 1 Introduction

## 1.1 Background

The Ugandan power sector is in the process of being restructured, and private participation introduced into the industry. Simultaneously, a new regulatory institution, the Electricity Regulatory Authority (ERA) has been established, and is in the process of developing and applying a new regulatory framework for the industry.

The ERA has a co-operation agreement with the Norwegian Energy and Water Resources Directorate (NVE). Under this co-operation, ECON Centre for Economic Analysis has been contracted to assist with special pricing studies for the Ugandan electricity sector. An initial report, *Cost Structure and Tariff Study for Uganda*, was submitted in February 2001. ECON was subsequently requested to extend this work in a number of areas. One such area was further analysis of the cost structure and pricing of power from existing generation assets – Nalubaale and Kiira power stations. This report sets out our findings from this analysis.

Nalubaale and Kiira power stations on the Nile River are currently owned and operated by the Ugandan Electricity Board (UEB) – a state-owned enterprise. In the course of 2001, these assets will be separated from UEB's network assets and operations in a separate subsidiary company – UEB Generation. From 2002, these assets are to be leased to the private sector through a concession arrangement.

Our analysis focuses on the proposed generation pricing contract and associated risk allocation. We further look at alternative ways of managing risk through contractual and pricing mechanisms.

Our approach is reflected in the structure of this report as follows:

- Analysis of cost structure of generation;
- Sensitivity of cost structure to variation in key parameters;
- Analysis of risk transfer in pricing agreement;
- Assessment of alternative risk transfer arrangements, including assessment of prices under a management contract.

The study is based on the information provided by ERA, the Utility Reform Unit (URU), and UEB. The data cover a period from 2000 to 2016, and the analysis is

focused on the period after 2002 when the leasing agreement for Nalubaale and Kiira is planned to be implemented.

## 1.2 Generation price structure

The generation concessionaire, Genco, will lease and operate Nalubaale and Kiira power stations from UEB Generation. The Transmission Company will act as the single buyer of electricity supplied to the transmission network in Uganda, and the sole exporter of power.

In principle, prices between Genco and the Transmission Company will be negotiated between these parties, and will be subject to oversight and approval by the ERA. In practice, the price structure will be determined prior to the establishment of the concession agreement, and the level of prices will be determined as a result of the process of bidding for the concession.

The proposed pricing structure for Genco's sales is a tariff for power made available. That is, a "Capacity Price" expressed as UGXs per MW, will be calculated as a function of Genco's revenue requirement and the maximum capacity made available by Genco.

The Capacity Price is calculated as:

$$\text{Capacity Price} = \frac{\text{Genco Revenue Requirement}}{\text{Maximum Capacity} * \text{Target Availability}}$$

Actual payments from Transco to Genco will be calculated for each hour of the day in the following manner:

- In an hour where a unit's full capacity is made available, payment will be equal to the product of the Capacity Price and the unit's capacity
- In an hour where less than a unit's full capacity is made available, payment will be equal to 50 percent of the product of the Capacity Price and the actual capacity made available.

Thus, it can be seen that the Revenue Requirement of Genco is a key parameter in determining power prices. This quantity will be regulated by ERA as described below. However, potential concessionaires will be asked to bid their required rate of return on investment, which will influence ERA's calculation of the revenue requirement.

## 1.3 Regulation of generation prices

The revenue requirement of UEB Generation has been set by ERA for 2001. The revenue requirement of Genco for 2002 will be determined by ERA once Genco's rate of return has been determined.

ERA will revise the revenue requirement as from 1 January 2003, and thereafter every 36 months. ERA will conduct a price review prior to each resetting of the tariff. This price review will include analysis and verification of information provided by Genco.

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

Since the proposed regulatory framework allows full transfer of the generation price onto the end-users, it is Genco's revenue requirement that is the relevant parameter in assessing the end-user consequences of the generation contract. Subject to the target availability and operating efficiency being met, Genco will charge Transco the revenue requirement approved by the ERA.

## 2 Generation cost structure

This chapter will analyse the cost structure of generation at Nalubaale and Kiira power stations based on the proposed generation contract and regulatory framework.

The structure of costs presented here determines the Revenue Requirement of Genco, and hence is the determinant of the capacity price and charges to Transco.

### 2.1 Data sources

The generation cost structure presented here is established on the basis of data and calculated revenue requirements provided by URU and UEB. The data and calculations have been provided to us in the following spreadsheets:

- UEB PROFORMA ACCOUNTS REV-B.xls
- Companies' Budgets 2001-C.xls
- Supply & Demand A.xls
- Loan Analysis.xls
- Tariff Calculations C.xls
- Tariffs 2001 Calc – C.xls

The scope of this study does not include assessment of the validity and accuracy of these data, though any obvious discrepancies would be further investigated. Such doubt has not been raised, though we have applied a set of revised demand projections. The analyses in this report use the demand scenarios based on the revised forecasts produced by Electricité de France (EdF) in 2000. These data are found in a separate spreadsheet (demand summery.xls).

In the cost data provided to us, certain costs items are expressed in nominal terms, i.e. taking inflation into account, and other costs are in real terms, i.e. expressed in today's money. We have made some modifications in order to differentiate between costs expressed in nominal and real terms. These modifications and further calculations are provided in a separate spreadsheet (Generation costs.xls).

The cost elements are estimates based on the costs of UEB in 1999 and 2000, and the Lahmeyer study of required investments in the power sector of Uganda. These estimates are provisional, and the regulatory framework describes a revision every 36 months of data and assumptions. Naturally, the accuracy of results will decrease towards the end of the timeframe analysed here.

## 2.2 Elements of the cost structure

From 2002, the costs that make up the Revenue Requirement of Genco are:

- Lease fee paid to UEB Generation
- Operating expenses incurred by Genco
- Depreciation of assets owned by Genco
- Return on assets owned by Genco
- Income tax liabilities of Genco

The lease fee itself is to be determined by the Government of Uganda. It is to be based on the costs incurred by UEB Generation, which are made up of:

- Depreciation expenses of assets owned by UEB Generation
- Interest payments of UEB Generation and/or return allowed for UEB Generation
- Administration fee

It is anticipated that UEB Generation will continue to invest in new assets over the next year or more. This is in order to further extend capacity at Nalubaale power station. This will increase the asset base owned by UEB Generation, and will result in additional debt accrued to UEB Generation. Both these factors will influence the lease fee paid by Genco.

We describe in more detail below each element of costs.

### **Operating expenses**

This represents the cost of operation and maintenance at Nalubaale and Kiira. In 2001 this will be the expenses of UEB Generation, while the concessionaire will bear these costs from 2002 onwards. The main expenses are expected to be salaries and staff related costs, maintenance and repairs on the hydropower units, and goods and services.

From 2003 onwards the ERA is expected to require real reductions in the operating expenses reflecting possible efficiency gains. The real annual reduction in operating expenses is expected to start at 5 percent per annum and then gradually ease and stabilise at 2 percent from 2007 and onwards.

### **Depreciation expenses**

Depreciation on assets normally represents a large portion of the total costs of hydropower generation. In this analysis it is important to note that there are two asset bases that are depreciated. The depreciation of the UEB's assets is included in the lease fee, while the depreciation of Genco's assets is directly reported as part of the concessionaire's costs.

Depreciation is calculated at a rate of 2.5 percent. While the Government of Uganda allows Genco a much higher depreciation rate for tax purposes (50%), ERA will set prices based on the economic life of assets. Genco's depreciation costs are expected to increase according to investments in new assets. Since at the

start of 2002 the concessionaire will own no assets, the Genco will not be given any depreciation allowance for 2002.

### **Interest expenses**

These expenses are divided into three categories:

- interest on the portion of UEB's existing debt that is allocated to UEB Generation,
- interest on UEB Generation's additional debt, and
- Genco's debt.

UEB's existing debt is the debt accumulated prior to 2001, and it consists largely of international loans from development agencies<sup>1</sup>. The loans are given in several different currencies and varying conditions and interest rates apply. This makes this cost element vulnerable to currency fluctuations. Responsibility for this debt is allocated to UEB Generation, Transmission and Distribution in proportion to the asset values assigned to these three groups. UEB Generation takes responsibility for 62 percent of the existing debt and interest obligations.

The Government of Uganda has proposed restructuring UEB's debt obligations. The measures proposed are to convert a portion of the debt to equity and to convert certain debt to more concessionaire terms. Both these measures will reduce the interest obligation of UEB Generation.

UEB's new debt, the debt incurred during the period studied, will be accumulated in the first years as investments in Nalubaale power station are completed. The debt and interest calculated is included as a fixed item, and the interest rate is assumed fixed.

Genco's interest expenses are related to the financing of investments during the concession period. An allowance for interest expenses additional to the return on assets would amount to double counting the cost of capital. Consequently, the revenue requirement only has an allowance for Genco's return, and no allowance for interest paid by Genco.

### **Return on capital**

UEB Generation may require a return on its capital employed in generation. The return should be included in the lease fee, and will replace the interest expenses in the lease fee. The level of return affects the size of the lease fee and thus the total costs of generation.

A return rate that generates revenue above the costs of servicing UEB Generation's debt obligations would generate a positive net income. The Government of Uganda has signalled that it will seek to minimise electricity prices rather than generating profits from its ownership of assets. Thus the proposed revenue requirement does not allow for a return on UEB Generation's

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<sup>1</sup> The loan portfolio consists of varying loans and contributions from several international institutions and developing agencies from several countries. Details are in the spreadsheet Loan analysis.xls provided by the Transaction Advisers.

assets. Instead the lease fee is based on the need to service UEB's debt obligations.

The concessioning process will require potential concessionaires to bid their required return on investment. ERA will use this rate of return in its calculation of the Revenue Requirement. The return should reflect the market cost of capital. Genco's return on investments in the base case is calculated as 20 percent. A withholding tax of 15 percent is added so that a 20 percent return after-tax return is actually calculated as 23<sup>2</sup> percent.

### **Income tax**

The income tax paid by UEB Generation and Genco will be related to the level of return requested. Naturally it will also reflect the given level of tax on income at any time. The corporate income tax is calculated as 30 percent of the pre-tax return.

In the case of UEB Generation, where the lease is set to cover interest expenses and not a return on investment, there will be no net income and hence no tax liability.

In the case of Genco, there will be tax liability on equity returns. The cost structure at present assumes that all capital is equity financed, and so an allowance for tax on the full return is made. In practice, Genco's tax liability will be influenced by at least two factors:

- The level of debt financing used by Genco, since interest expenses will offset tax liabilities
- Accelerated depreciation of assets, allowed for tax purposes. In fact this defers tax obligations rather than removing them. Hence, it is appropriate for ERA not to take this into consideration in the calculation of the revenue requirement.

## **2.3 Base case results**

### **Base case assumptions**

The results presented in this section are all based on the base case set of assumptions. Changes in the separate cost elements will be assessed in the following chapter. The base case has the following assumptions:

- Genco's return on investments ..... 20.0%
- Interest on new UEB debt ..... 8.0%
- Depreciation of assets..... 2.5%
- Ugandan inflation ..... 4.5%
- Currency devaluation ..... 14.5%
- Hydrology scenario ..... avg - Average discharge

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<sup>2</sup>  $20 + 20 * 0.15 = 23$

- Demand scenario ..... base - EdF base revised (2000) forecast

The cost factors in the list above are already explained in section 2.2. Assumptions about the other underlying economic variables are based on previous work by ECON for ERA.

EdF revised demand scenarios seems to be well supported and justified. Thus it is reasonable to use the base from this set of scenarios as the base case here. Hydrology is assumed to be average. This means 50 years conversion period from 40 to 100 years hydrology projection data. As seen later, the Hydrology has little impact on the costs, so no further elaboration is given here<sup>3</sup>.

Ugandan inflation is assumed to be 4.5 percent. This is just above the average of the underlying inflation over the two last years. The annual depreciation of the Ugandan shilling is assumed 14.5 percent. This is at the average for the two last years, and equals the Ugandan inflation plus a 10 percent real shilling depreciation. These assumptions are consistent with the historic data presented in Annex B.

### **Total costs at Kiira and Nalubaale**

Costs can either be expressed in nominal terms, i.e. the money of the day, or in real terms, i.e. today's money. Nominal costs include the effect of inflation, whereas real costs do not. In analysing the cost structure of generation at Nalubaale and Kiira, it is useful to express costs in real terms.

The calculations done by the Transaction Advisers in the *Tariff Calculations C* spreadsheet reports different costs in different terms. The operating expenses are given in real terms, while the other costs are denominated in nominal terms. Therefore we have recalculated<sup>4</sup> the costs to construct a full set of data in both real and nominal terms.

Figure 2.1 illustrates the cost structure of generation at Nalubaale and Kiira, for the base case set of assumptions. Total costs start at approximately 61 bn UGX, increase over the first two years, then decline to about 50 bn UGX in 2011 before they increase to approximately 54 bn UGX in 2016. The most important features of the cost structure are:

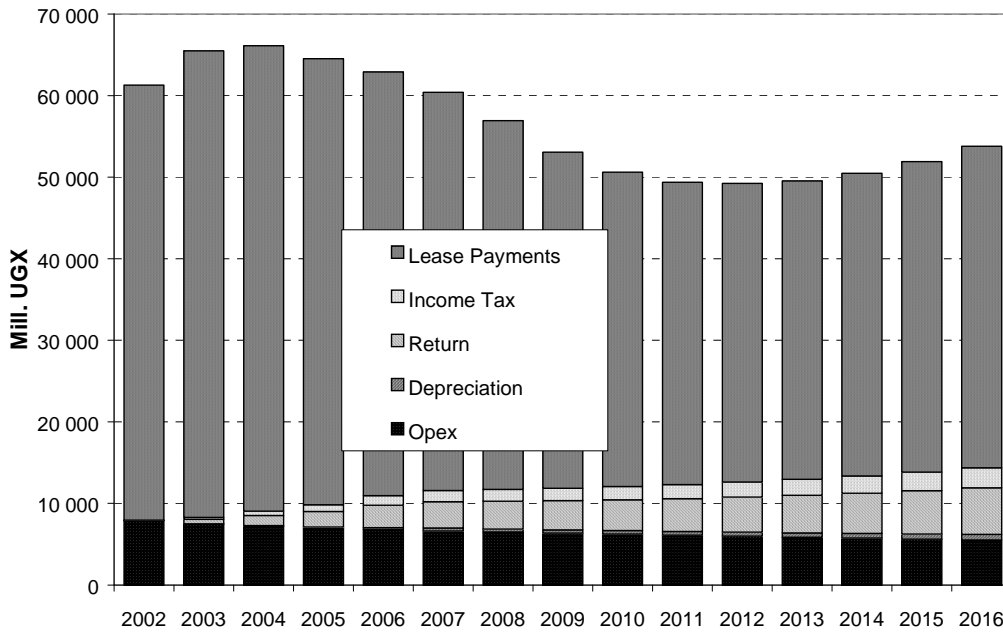
- The lease payment contributes the largest portion of total costs;
- Costs decline in real terms by approximately 10 percent over the 15 year period examined;
- This decline in costs is due to a reduction in the lease fee.

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<sup>3</sup> Please see the *Cost structure and tariff study for Uganda, ECON 09/01* for more information.

<sup>4</sup> This calculation is found in the spreadsheet: Generation costs.xls

*Figure 2.1 Cost structure of generation at Nalubaale and Kiira (base case, real terms).*



It should be noted that the dominant element of the cost is the lease fee. Since this is specified in US\$, it is sensitive to currency devaluation. While this will be explored in more detail in Chapter 4, we present in Figure 2.2 the projected costs (in real terms) for the case of a 4.5 percent annual devaluation. It can be seen that the lease fee declines dramatically over the period, resulting in a 60 percent decline in total costs by 2016.

*Figure 2.2 Cost structure of generation at Nalubaale and Kiira, in real terms (4.5% inflation & devaluation)*

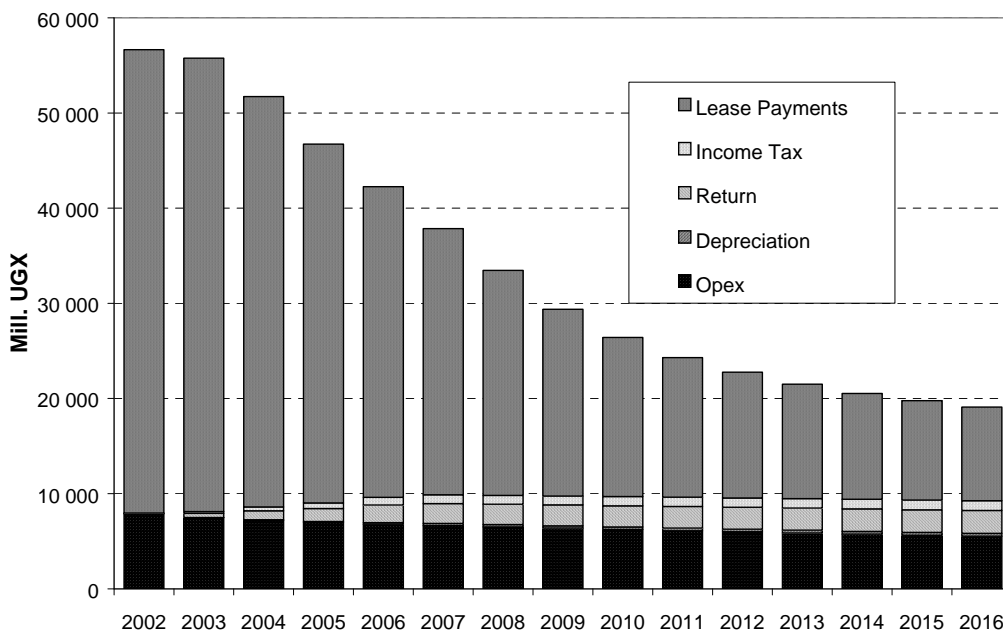
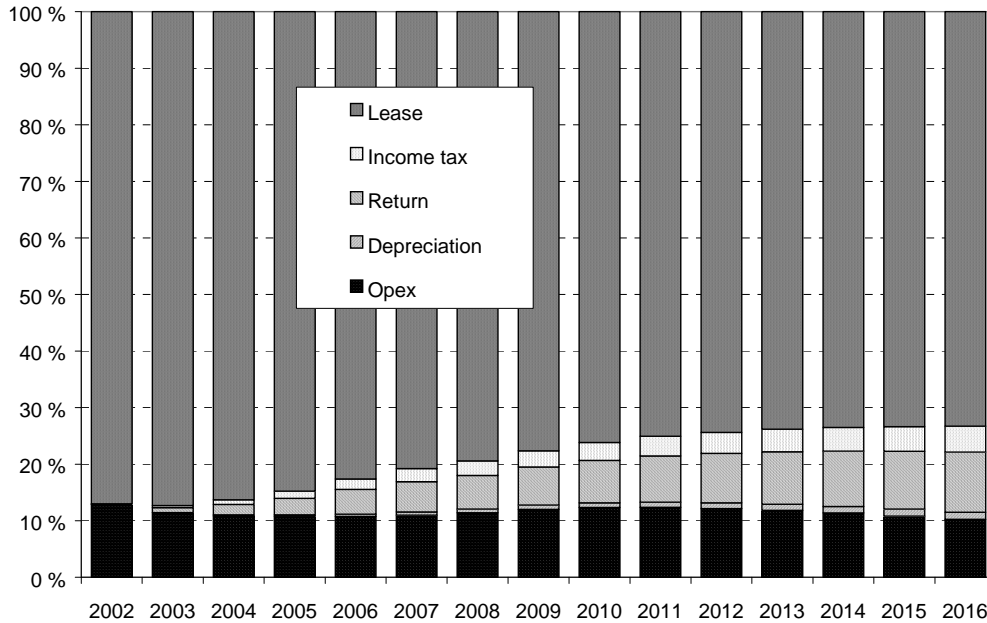


Figure 2.3 clearly shows the significance of the lease fee in the annual costs of generation. In the early years, the lease fee contributes 86 percent of total costs,

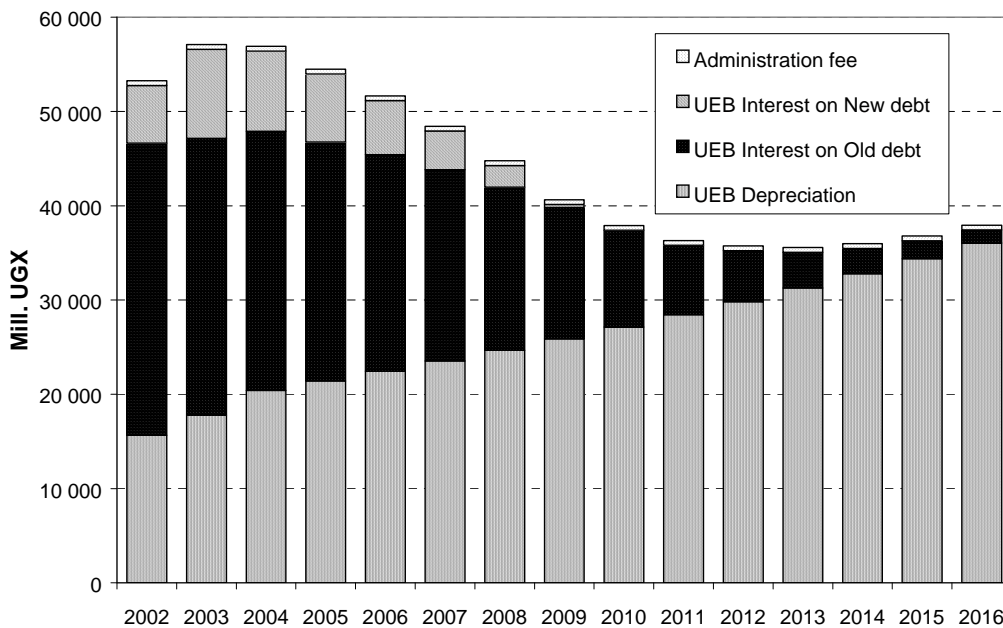
and this declines to 73 percent by 2016. The second largest portion is operating expenses (Opex), followed by Genco's return, income tax, and depreciation on Genco's assets.

*Figure 2.3 Relative shares of the cost components*



Given the significance of the lease fee in the cost structure, it is useful to examine this cost element in model detail. The breakdown of the lease fee into its different elements is shown in Figure 2.4.

*Figure 2.4 Composition of the lease fee, in real terms*



From Figure 2.4 it is easy to see that interest expenses decline dramatically through the period. This is a result of debt reduction over the period. Should the proposed debt restructuring of UEB be implemented, one can expect to see the

interest portion of the lease fee being reduced, particularly in the early years. This would have a significant impact on the costs of generation at Nalubaale and Kiira.

Depreciation costs are increasing due to the indexing to US dollars. The indexing to dollars is consistent with depreciation actually representing the down payments on the loan obligations denominated in foreign currencies. From much of the same reason the lease fee will be indexed to US dollars according to the proposed regulatory framework.

It should be noted that depreciation expenses are calculated on the revalued asset base. The use of historical asset values would result in lower depreciation expenses.

### **The unit cost of generation at Nalubaale and Kiira**

The end-user consequences of generation costs will be related to the unit cost rather than the total costs, that is the cost per unit of electricity sold. Thus a brief overview of the unit cost of power is provided here. The unit cost is the total costs of generation divided by delivered energy. The unit cost of power equals only the power supply element of the average generation tariff. Thus the unit power cost excludes the cost of transmission and distribution. The formula proposed for pricing to end-users implies that the average price Ugandan consumers pay for power is given by:

$$\text{Unit cost} = \frac{\text{Total cost of generation}}{\text{Total Ugandan demand} + \text{Exports}}$$

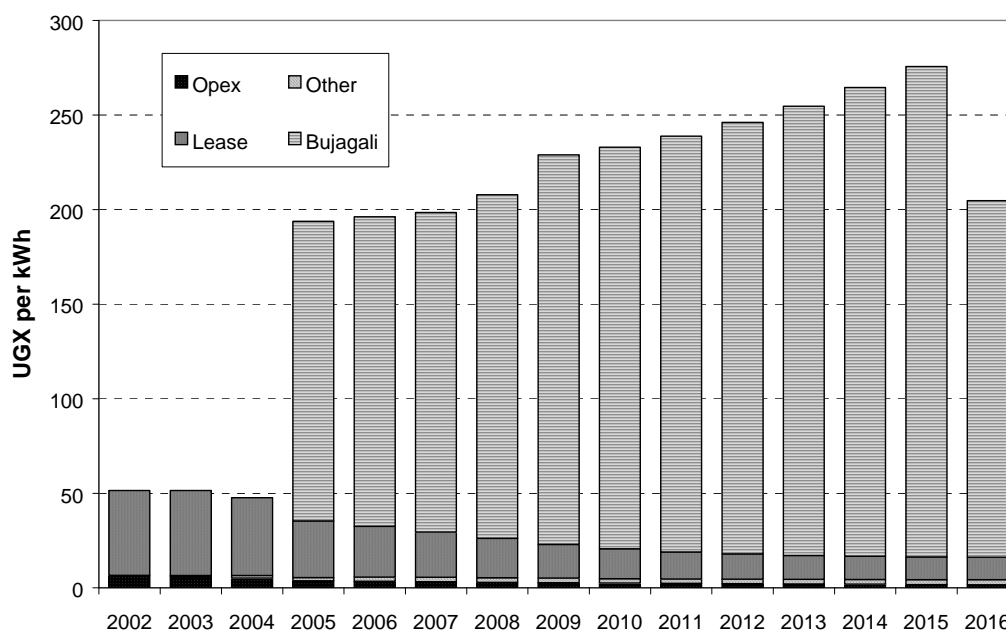
The total unit cost of power to end-users will be equal to the unit power cost at Nalubaale and Kiira up to 2005. In 2005 the Bujagali power station comes on-stream, and affects the total costs and demand. From 2005 and onwards the unit cost paid by Ugandan consumers is given as the contribution from Nalubaale/Kiira and from Bujagali.

Under the proposed generation contract the Genco will be allowed to charge a tariff based on available capacity at Nalubaale and Kiira. The installed capacity in 2002 is expected to be 260 MW. Today's capacity at Nalubaale is 180 MW (10 units of 18 MW each) and 80 at Kiira (2 units of 40 MW). Up to three further units of 40 MW are possible to construct at Kiira, but the water discharge may restrain the possibility of running that much capacity at a continuous basis.

Bujagali will come on-stream with 200 MW in 2005 based on a take or pay contract. From 2005 for several years, Uganda will have surplus generating capacity. If this surplus can not be exported, then Ugandan consumers will have to pay a higher price for power consumed. However, this is a consequence of the costs of Bujagali and not Nalubaale and Kiira. Hence the unit costs of power from Nalubaale and Kiira will be unaffected by the costs of Bujagali.

The unit costs charged to Ugandan consumers from power generated by Nalubaale and Kiira are shown in the figure below. Also shown is the effect of the costs of Bujagali.

Figure 2.5 Unit cost of power supply, real UGX/kWh (base case)



The unit cost of power supply from Nalubaale and Kiira decreases due to two factors:

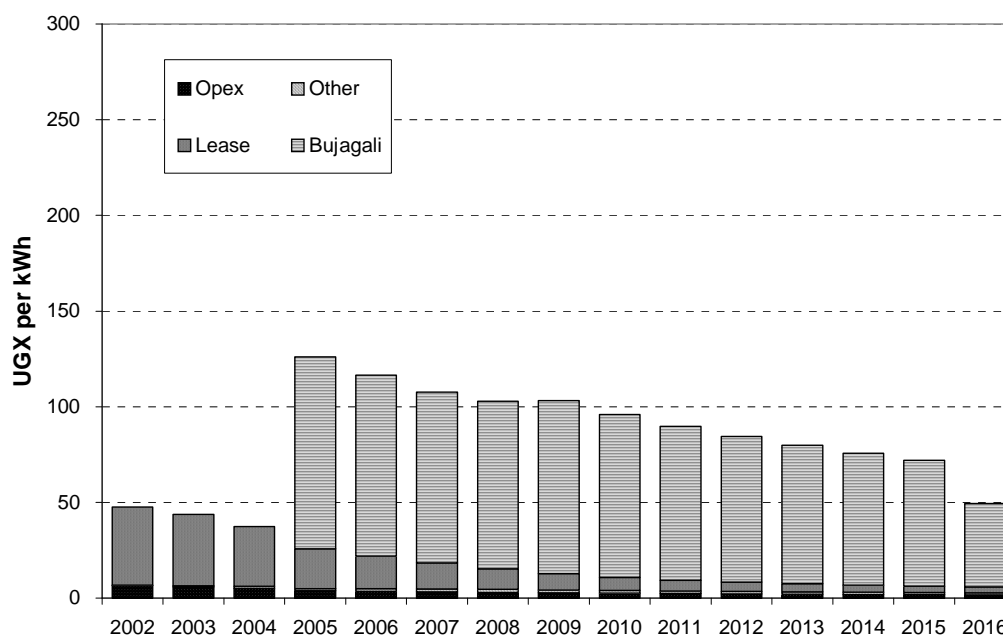
- The reduction in actual costs of Nalubaale and Kiira is reduced by some 10 percent over time.
- The increase in demand – both exports and local demand. This means that the costs are spread over a larger consumption base.

Related to the latter it should be noted that Bujagali allows a higher total demand than with Nalubaale and Kiira only, i.e. the constraints on demand are lifted. This implies that Bujagali indirectly reduces average unit cost of power from Nalubaale and Kiira, though the total unit cost of power will increase considerably.

The costs of Bujagali are much higher than the costs of Nalubaale and Kiira, and consequently a jump in total unit cost of power supply is seen in 2005 when Bujagali comes on-stream. Under the base case assumptions the leap in total unit cost is approximately 300 percent.

Payments to Bujagali will be in foreign currencies, and the increasing costs are due to the annual devaluation. Devaluation equal to inflation (4.5%) will give considerably lower costs of Bujagali, as seen in Figure 2.6. Under such an assumption the unit cost of Bujagali also decreases over the period. Once again, this emphasises the importance of exchange rates in the costs of power in Uganda.

Figure 2.6 Unit cost of power supply, real UGX/kWh (4.5% inflation & devaluation)



## 2.4 Key sensitivities

Annex A presents the results of a sensitivity analysis undertaken of the cost structure of generation at Nalubaale and Kiira. The sensitivities tested include:

- Ugandan inflation;
- Currency devaluation;
- Lease fee;
- Genco's rate of return;
- Hydro discharge; and
- Ugandan demand.

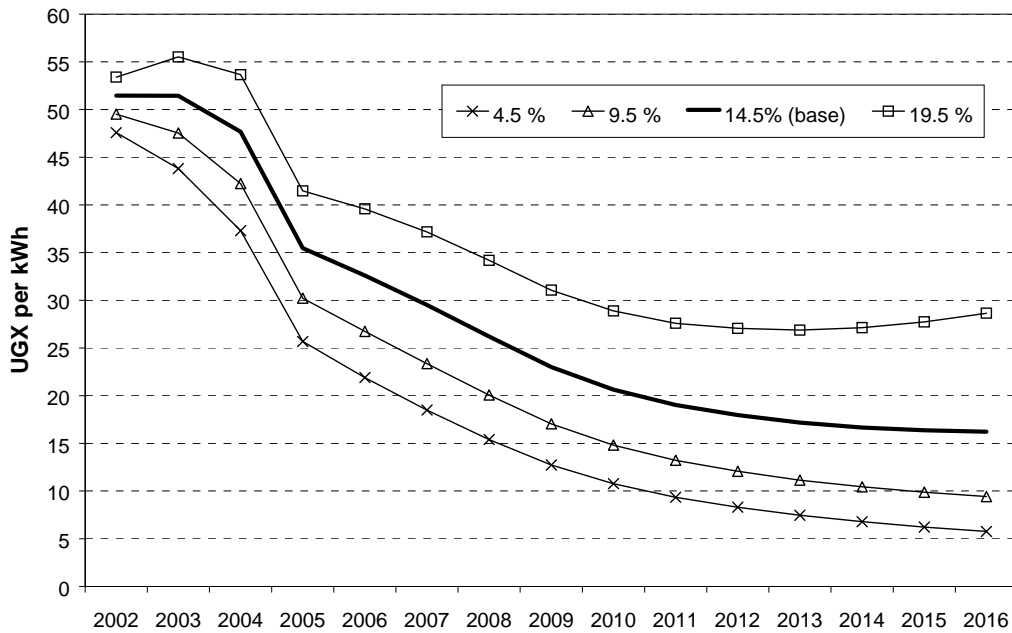
The analysis found that major changes in costs will be caused by changes in the following three key factors: devaluation of the Ugandan shilling; the size of the lease fee; and Ugandan inflation.

The lease fee constitutes approximately 80 percent of total costs of generation at Nalubaale and Kiira under the base case assumptions. Any change in the lease fee thus induces a significant change in total costs. Replacing the interest obligation with a 10 percent return requirement would approximately double the average unit cost of power supply from Nalubaale and Kiira. Government sets the lease fee, and this highlights the significance of Government's choices for the lease fee. It should be noted that the proposed debt restructuring of UEB will have a significant impact on the costs of Nalubaale and Kiira, with the potential to significantly reduce costs passed through to customers.

A large portion of the total costs of generation is denominated in dollars. The lease fee is assumed to be in dollars, as the loan obligations of UEB Generation

are also in hard currency. Further, the Genco's own investments will also be indexed to the dollar in regulatory system, thereby further adding to the dollar portion of the costs. As a consequence, depreciation of the Ugandan currency will have a large impact on total costs in shilling terms. The cumulative effect of annual depreciation gives a considerable effect over the lifetime of the concession, as shown in Figure 2.7.

Figure 2.7 Sensitivity of unit cost of generation to devaluation (real terms)



Devaluation may also be related to inflation, another important economic variable. Ugandan inflation will induce currency devaluation. All other factors being equal, increased inflation should lead to currency depreciation so that costs, in real Shillings, remain constant. Despite this effect, higher inflation will reduce the real unit cost of generation at Nalubaale and Kiira. This is because certain cost elements are assumed insensitive to inflation, namely depreciation of historical assets and interest payments set at fixed rates. Of course the effect of higher inflation on nominal prices will be a greater price increase.

Unit cost is considerably less sensitive to the other parameters studied. It is worth noting that the average unit cost is not very sensitive to the Genco's rate of return on investments. This is to be expected as Genco owns no assets in 2002, and Genco's investments thereafter are modest relative to UEB assets and the size of the lease fee.

## 3 Risk transfer

### 3.1 Introduction

From the previous section it is clear that several parameters will impose risk on unit cost of generation at Nalubaale and Kiira. Three main risk elements are highlighted:

- Risk of changes in lease fee. This can be characterised as a political risk since it is related to the decisions of Government;
- Inflation risk; and
- Exchange rate risk.

Other factors will be relevant in a risk transfer analysis. Typically demand, export, operational costs, investments, outages and availability may well induce risks of changed costs or revenues. An analysis of the different risk factors and the risk transfer is given in section 3.2.

#### **Cost of risk**

From a regulatory perspective there are two key questions related to the handling of risk:

- Does the risk represent costs?
- If so, who will bear these costs?

The first question can lay the ground for a theoretical discussion of the concepts of risk and how this is related to the cost of capital. Risk is related to changes that may have both an upside as well as a downside. The normal risk averse investor will generally require a compensation in cash flow or include a risk premium in return requirements to cover for the relevant risks. Here we will simply conclude that the relevant risk is the risk that induces higher cost of generation at Nalubaale and Kiira.

The risks can either be transferred by adjustment factors (compensation in cash flow) or they can be compensated in the return. Both ways will induce a cost. The use of adjustment factors may relieve the Genco from risk, but the compensating body will bear the costs. Increased return compensates Genco's risk, but will

increase generation tariffs, which at the end is paid by the end-users<sup>5</sup>. The price contracts determine the exact transfer of risk, and thus who will bear the costs.

Price stability is also influenced by risk transfer arrangements. Risk transfer to end-users will end to result in less stable prices due to the price adjustments involved. Retaining risk with the Genco, and compensating through increased return allowances, will mean more stable prices.

Who will bear the costs, is the key question in analysing the end-user consequences of the generation contract. The regulatory framework allows for most power supply costs to be transferred to end-users. Thus, much of the risk is placed on the end-users.

This identifies that there are two steps in the analysis of the risk. The first is the transfer of risk, and the second is whether the risk is reflected in the return/gains. This chapter will look closer at the different risk elements and the transfer of risk.

## **3.2 Risks and the transfer of risk**

There market participants affected by transfer of risks or costs are:

- Government of Uganda
- Genco
- Transco (single buyer)
- Disco
- End-user

Between each of these participants there is a transaction that will include contractual agreements that define the transfer of costs and risks related to changes in costs. The contracts are the lease-agreement, power purchase agreement, bulk supply agreements, and end-user contracts respectively.

In the following analysis of risk factors, the focus is on risks related to the generation contract, comprising lease, power purchase agreement, and price mechanism. The other contracts are, in this discussion, only relevant as transfer mechanisms for costs related to risk in generation. For each of the main risk factors, we will indicate the size of the risk, who will bear the risk, and how it is transferred.

Before going into details on different risk factors it is worth noting that there are three key risk transfer mechanisms described in the regulatory framework:

- Pricing structure with pass through of power supply cost to end-users;
- Revision of revenue requirements for each regulatory period; and
- Adjustment factors within each regulatory period.

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<sup>5</sup> This can be compared to paying insurance against risks, as opposed to carrying the risk directly.

The bulk supply tariff (BST) is the centre point of pricing structure and pass through of power supply cost. BST is calculated as follows:

$$\text{BST}^6 = \frac{\text{Transco's payments to Genco - portion of exports}}{\text{Ugandan sales} + \text{Exports}}$$

The BST is passed through to end-users. This implies that all costs included in the generation tariff will be passed on to end-users. Changes in total sales will change average BST, and thus effect the average unit cost of power for end-users.

The revision of Genco's revenue requirement at each price review will take account of changes in costs included in the generation tariff, including investment. The costs allowed for in the revenue requirements will be passed on to end-users through BST.

In between revisions, Genco's revenue requirements will be adjusted according to some factors. Again such adjustments will be passed on to end-users through generation tariff and BST.

### **Investment risk**

Genco is required to invest to meet quality of supply targets, and other relevant targets set by ERA. Prices are set by ERA, based on the expected investments. Still additional investments may be required to meet targets, to adjust for unanticipated changes in demand or other factors. This may give rise to investment risk.

Genco is not expected to undertake large investments, and the capital costs of new investments contribute only modestly to the total costs of generation at Nalubaale and Kiira. Therefore investment risk will be relatively small. The element of Genco's revenue requirement attributable to return on investment is less than 10 percent of the total. Investment risk is predominantly transferred to end-users through adjustments for actual investments and the update of the asset base at each price review.

For the period up to 2006 there are price adjustments for actual investments and under- or over recovery. This allows the Genco to adjust the generation tariff in response to actual investment, and so pass investment risks through to Transco and ultimately onto end-users. Any under or over-recovery as a result of actual investment being different from estimated will be charged or returned to consumers, implying that all investment risk is transferred to consumers.

After 2005, it is expected that prices will be based on expected rather than actual investment. This means that any costs or benefits of over or under investment in relation to the targets will accrue to Genco and not consumers. At each price review, the asset base will be reset. This means that Genco bears investment risk between reviews, and that at each review the risks are transferred to consumers. In fact, the ERA may adopt a policy of only transferring cost gains from lower than

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<sup>6</sup> ERA will decide what portion of export profits in previous quarter that shall be used to subsidize the BST.

anticipated investment, and not additional costs as a result of higher investment. Under this policy, consumers would only be exposed to the upside.

### **Inflation and exchange rate risks**

Inflation and exchange rate are two of the most uncertain underlying economic variables that may change the total costs of generation considerably. The sensitivity analysis in the previous chapter highlighted the possible magnitude of the inflation and exchange rate risks. These risks are expected to be considerable.

Under the proposed arrangements, end-users will also take the burden of these risks. Through the proposed price-adjustment mechanism for changes in inflation and depreciation of the shilling, Genco is compensated for additional costs from these factors.

Quarterly price adjustments are to be made for changes in exchange rate. This should guarantee that costs of forex fluctuations are covered. It may be that the lag in adjustments gives rise to some under- or over-compensation. Over time it is reasonable to expect this to be balanced, suggesting that all exchange rate risk will be transferred to end-users.

Adjustments for inflation will be made annually. This may give rise to some under- or over-compensation through the year effecting the cash flow somewhat. Still, in the long run this is expected to be less significant as a risk factor.

### **Operating costs and availability risks**

The regulatory framework stipulates an allowance for operating costs rather than simply passing actual costs through in the revenue requirement. This mechanism ensures that Genco takes the risk of variation in operating costs.

Similarly, the pricing mechanism is based on target plant availability rather than actual availability. This ensures that Genco takes the risk of reduced availability. Since operating costs and availability are most easily controlled by management, this allocation of risks to Genco is consistent with an incentive approach to regulation.

Should reduced availability (or transmission outages) result in undelivered energy, end-users will bear these costs. These costs, particularly for industrial consumers, are likely to be large – much larger than the reduced revenue to Genco that stems from the pricing formula.

### **Volume risk – Uganda demand**

Volume risks associated with variations in Ugandan demand are transferred to end-users. Payments to Genco are based on capacity made available and not power actually dispatched. Lower than anticipated demand will increase average power prices, and vice versa.

While demand is constrained (effectively until 2005), volume risks are not present simply because any increase or decrease in unconstrained demand will not significantly influence prices or power dispatch. However, the utilisation of Bujagali capacity made available in 2005 will depend on the underlying demand in Uganda, and will have a large impact on the unit price of Bujagali power.

However, our analysis of the sensitivity of prices from Nalubaale and Kiira indicates that this risk is relatively small, especially in comparison with the impact of the additional costs of Bujagali.

### **Export risks – price and volume**

There are two ways in which exports may induce risk:

- A direct volume effect on prices in Uganda; and
- An export revenue effect.

The direct volume effect will induce some risk to end-users equivalent to that of changes in domestic volume. This is described above, and will not be repeated. Still it is worth noting that it may be possible to increase exports in periods not coincident with domestic peak demand even under capacity constraints. Thus, off-peak exports may vary even in the years with constrained demand.

Transco's export revenue will change with both export volume and prices. Increases in these variables will increase revenue, and vice versa. This induces some export revenue risk. In the proposed regulatory framework it is stated that a portion of such export profits will be used to subsidise the BST in following quarter. Thus the export revenue level will influence the BST in the following quarter.

Exports contracts at prices below the BST have a paradoxical effect. Given the take-or-pay nature of generation contracts, the marginal cost of power purchases is effectively zero. Thus, exports at any price will reduce the costs imposed on Ugandan consumers. This is reflected in the pricing arrangements whereby additional export volumes (at any price) will reduce the price paid by Ugandan consumers. However, exports at too low a price<sup>7</sup> will generate financial losses for Transco since the lost revenue from reduced prices to Ugandan consumers will not be matched by increased revenue from exports. As a result, there is a mismatch between Transco's incentives and consumers' incentives.

Transco's incentive to export at prices above Ugandan prices is reduced if a portion of export profits is used to subsidise local prices. At present, however, the current proposal has all export revenue retained by Transco.

### **Political risk**

The object and limitations of this report does not allow a discussion of the overall political risks in Uganda. The only political risk that we will assess here is the risks related to changes in lease fee.

The method for calculating the lease fee is chosen by the Government of Uganda. Thus the risk from changes in the lease fee can be viewed as a form of political risk. From the sensitivity analysis it is clear that changes in the lease fee may give considerable changes to the total costs of generation at Nalubaale and Kiira. Thus there is considerable risk related to changes in the lease fee. Still it must be

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<sup>7</sup> It can be shown that losses will be incurred if export prices are less than domestic prices times the ratio of Ugandan sales to total sales.

expected that the lease contract will constrain alterations to the lease fee. As mentioned earlier, the Government's objective for the lease fee is only to meet UEB loan obligations, and not to realise a profit. The political risk relates to possible changes in this policy.

The risk of change in the lease fee is transferred to the end-users. The regulatory framework states that ERA will change Genco's revenue requirement according to alterations in lease fee. Thus changes in the lease fee will be transferred into the BST, and by that passed through to end-user tariffs.

### **Risk of transmission network outages**

Network outages will cause less energy to be delivered to end-users. This will not influence the generation tariff, as the generation contract is based on available capacity at the power station. However, the BST is calculated on the basis of the energy fed into the transmission network, which must equal the sum of energy delivered and losses. Thus a reduction in energy delivered due to network outages will raise the BST. Again this is passed onto end-users through the power supply element of the tariff. The risk therefore appears to be transferred to end-users.

However, it seems reasonable that the contracts between Transco and Disco will be set so that Transco absorbs the effect of network outages. This may be an issue that the regulator will have to follow up to ensure that the allocation of risks sits with the agent responsible.

The risk of outages may also interrupt production or other businesses and thus induce costs to end-users. By that it may represent significant risk for some types of consumers in a similar way as mentioned under availability risk.

## **3.3 Summary**

Our analysis of risks related to the generation contract contribute to the following key conclusions:

- End-users carry most risks, including volume, investment, foreign exchange, inflation and political risks (in so far as they relate to the lease fee).
- Genco is exposed to risks relating to operating costs and availability, and after 2006 may be exposed to a portion of the investment risks; and
- Transco is exposed to risks related to export prices, and should be exposed to the risks of network outages.

These conclusions can be further illustrated through a diagram of risk transfer for unit generation costs according to the proposed regulatory framework.

*Figure 3.1 Representation of risk transfer*

<b>Risk</b>	<b>Genco</b>	<b>Transco</b>	<b>Disco</b>	<b>Customer</b>	<b>Mechanism</b>
Investment	$\lambda$			$\lambda$	Revision of asset base
Inflation				$\lambda$	Price adjustments
Currency				$\lambda$	Price adjustments
Opex	$\lambda$				Allowance in revenue req.
Availability	$\lambda$				Capacity price formula
Exports				$\lambda$	Capacity price formula
Uganda volume				$\lambda$	Capacity price formula
Lease fee				$\lambda$	Allowance in revenue req.
Network outage		$\lambda$			Transco-Disco contract

The risks borne by consumers constitute the largest risks in the supply of power, particularly those relating to foreign exchange. In recognition, it should be anticipated that the operating companies receive a lower return on capital. However, this will be determined as the outcome of the bidding process and it is difficult at the stage to determine whether consumers will actually benefit from the proposed risk transfer arrangements. On balance, our view is that the reduced rate of return is unlikely to counter balance the costs associated with the risks transferred. On the other hand, it may be that investors simply would not invest in the Ugandan power system unless these risks are transferred away from them.

## 4 Alternative risk transfer arrangements

This chapter will assess some alternative arrangements that can be used to change the transfer of risk. The transfer of risk influences incentives and costs related to the participants' behaviour.

In general, possible alternative arrangements relate to:

- Contractual arrangements;
- Price structure; and
- Price adjustment mechanisms

As mentioned in the previous chapter, there are two main ways of compensating risks. These are compensation in cash flow or inclusion of a risk premium in the return requirement. While the adjustments in cash flow will pass on the fluctuations in costs, the risk premium will take account of the fluctuations through a generally higher tariff. Thus the question of risk transfer is related to price stability as well as incentives.

### 4.1 Contractual arrangements

The current system proposes a concession arrangement. This effectively leases existing assets to the concessionaire, and imposes an investment obligation on the concessionaire. The concessionaire's revenue, as discussed above, is based on a price for capacity made available. The method of determining that price means that most risks are transferred to customers.

Alternative contractual arrangements to the concession are:

- Privatisation, i.e. sale of the existing assets; and
- Management contract, i.e. no obligation to invest

#### **Asset privatisation**

Privatisation of existing assets introduces an additional variable into the pricing equation, i.e. the market value of the assets in question. The value of the assets will be a function of the future expected revenue stream. If this revenue stream has relatively few risks in it (i.e. they are mostly transferred to customers as in the current arrangements), then the value of the assets will increase. If the privatised

entity is expected to absorb a greater share of risks, then the asset values will be discounted by investors.

In this way, Government and the regulator can determine a pricing framework that allocates risks as they wish, and the outcome will be a change in the privatisation value. In this way, the costs of risks are rolled up at the time of the transaction and charged to Government in the form of a reduced sale price.

Government's policy is to realise sufficient revenue to meet UEB's debt obligations. Hence, as long as the privatisation proceeds exceed the debt level, Government will achieve its policy objective and effectively eliminate its debt obligations related to UEB Generation.

Under a privatised arrangement, the risks of changes in lease fee are obviously no longer evident. Other risks will depend on the arrangements made for prices and price adjustments. These will be discussed below in sections 4.2 and 4.3.

### **Management contract**

A management contract would absolve the concessionaire from the obligation to invest further in the industry. Any investments would be included in UEB Generation's assets, and would influence the asset component of the price.

The difference between a management contract and the proposed systems effectively relates to the cost of capital, and the incentives to improve investment efficiency. The analysis on the sensitivity to cost of capital clearly indicates that the results are not particularly sensitive to this. On the other hand, while Government at present is able to raise finance cheaply, there may well be medium-term constraints on this. In this sense, a management contract would fail to introduce new sources of capital for the industry.

Regarding incentives to improve investment efficiency, once again new investment costs do not make up a large portion of the costs of power from Nalubaale and Kiira. Consequently, improvements in investment at these power stations will not have a large impact on prices. Further, for the first 5 year period, the regulatory framework passes through investment risk to customers, and so incentives for a private operator to invest wisely will not be strong. However, management contracts may result in conflict between management and asset owners – the former wishing to see additional investment and the latter wishing to avoid it. The difficulty is that management are not exposed to the risks of investment, while owners do not have the insight that management has into the business.

Our conclusion is that there would be little significant difference between a management contract and the current concession arrangement, at least for Nalubaale and Kiira assets. The present arrangement is, in fact, very similar to a management contract with incentives and risks largely constrained to the factors which management have a direct responsibility for, i.e. operating costs and availability.

## 4.2 Price structures

The present price structure is a capacity fee that is paid for any capacity made available. While there are penalties for less than target availability levels, the price embodies a “take or pay” type of arrangement that is similar to the contract negotiated for Bujagali.

The effect of this price structure is that Genco takes no volume risk. Regardless of demand growth in Uganda, Genco will get paid its revenue requirement as long as target availability levels are met.

The principal alternative to the present type of price structure is a price based on energy or power dispatched. Under this arrangement, prices would be based on anticipated demand/energy supplied, with the Genco taking risk for sales above or below the expected level. It should be noted that this approach has been adopted for distribution pricing in Uganda, where distribution prices are based on anticipated rather than actual sales.

A disadvantage with a price system based on energy or power dispatched is that with 80 percent of the cost of generation related to the lease fee, the risks for Genco may be unacceptably high. These risks are not possible to compensate through the return on investment, which in fact takes up a small portion of the total revenue requirement. Thus, any system such as this would have to be based on a two-part tariff, i.e. a fixed monthly fee to cover a large part of the costs (i.e. the lease), and a variable tariff to cover other elements of the costs. Alternatively, the lease fee may be constructed as a variable charge (e.g. shillings per kWh), meaning that volume risks get shared between Genco and UEB Generation.

There will be further complications when Bujagali is commissioned. Since Bujagali is a “take or pay” contract, the marginal cost is zero. Consequently, if Genco charges a unit fee, Transco would always favour purchases from Bujagali over purchases from Genco. In the situation of excess capacity, this would imply a very high volume risk for Genco simply because in 2005 much less power would be purchased from Genco compared with previous years. Again, a private investor would be reluctant to take a volume risk of this scale if the principal competitor, i.e. Bujagali, was not exposed to the same risk.

Thus, we conclude that an alternative price structure for Genco is difficult to implement if Bujagali is to be compensated through a “take or pay” capacity fee. The volume risks arising from the difference in Bujagali and Genco price structure would be too high.

## 4.3 Price adjustment mechanisms

Risk transfer is present in the price adjustment mechanisms. In particular, the transfer of foreign exchange and inflation risk is dealt with in the automatic quarterly and annual adjustments. Similarly, the transfer of investment risk is dealt with in the adjustments of the asset base and provision for over/under recovery.

Alternative adjustment mechanisms can be designed to reallocate risk among the various parties. We consider here the following alternative adjustment mechanisms:

- Use of an adjustment factor;
- Use of a sliding scale mechanism; and
- Use of an adjustment band.

### **Adjustment factor**

One way on giving partial adjustments is by the use of an adjustment factor. This means that only a portion of cost changes is compensated. One example of an adjustment factor is the portion of costs that are indexed to foreign exchange rates. Reducing this portion will reallocate risk from customers back to Genco.

### **Sliding scale**

A system of sliding scale is in principle the same as that of an adjustment factor. The only difference is that the factor is given a schedule so that it will change according to the significance of the cost changes. If the change is relatively little the adjustment factor is small, while with a major change the adjustment is large. A sliding scale will thus change the incentive properties for the participants according to the significance of the fluctuations in costs or revenue. The construction of the sliding scale can mean that risks are allocated to both Genco and consumers.

### **Adjustment band**

It is also possible to adapt a stepwise system of partial adjustment by applying a band. If fluctuations in costs or revenues are within a band, no compensation is given, while some (or full) compensation is given outside this band. This will give the entity full incentives to reduce risk within the band, and at the same time providing a guarantee against “catastrophes”.

### **No adjustment**

An alternative is, of course, not to transfer risk at all. By fixing prices or income with no adjustments allowed, most risks will be taken by Genco. This gives full incentives to risk minimisation. This will typically be an option where the risks are influenced strongly by the behaviour of the firm, and is in fact currently proposed for operating costs and availability risks.

## **4.4 Risk premium**

If risks are not compensated directly, the risk averse investor would request a risk premium to be included in the return requirement. Thus the risk would also in this case be compensated as an extra margin in the tariff, similar to paying insurance. The investor will handle risks by diversification of investments. That is, the investor would spread his investment portfolio on different sectors and areas to not being severely hit by fluctuations in one specific variable, and in this way may be better suited to handle risks.

The Genco will minimise risks to increase return, and a risk premium would sustain such incentives, as the firm would keep all gains from the risk premium. But it may be that the risk is over compensated, and that the economy as a whole would be better off if Government carried the risks or they were transferred to customers.

As discussed above, one difficulty with applying this to the concession arrangement is that the lease fee takes a large share of the costs. With such a large share of the costs not under Genco's control, risks may be unacceptably large. In the case of a management contract, the risk of not meeting the costs of existing assets (i.e. the "lease fee") would remain with the Government of Uganda.

The principal alternative system is where assets are privatised. In this case, the discount for risk will be reflected in the price offered for Government assets, and hence the costs of risk would be borne by Government in the sale transaction.

## 5 Conclusions

The objective of this study has been to examine the cost structure of generation at Nalubaale and Kiira power stations, and to analyse the transfer of risks in the proposed price and regulatory system. In addition, we have briefly examined some alternative arrangements that would change the way risks are dealt with in the industry.

### 5.1 Cost structure

From 2002, the revenue requirement of Nalubaale and Kiira will be comprised of a lease fee paid to UEB Generation, operating costs at the plants themselves, depreciation of assets owned by Genco, a return allowance and taxation. The lease fee makes up approximately 80 percent of all costs, and is itself comprised of depreciation of assets owned by UEB Generation, interest payments on UEB Generation debt and a small administration fee.

In the first few years of the concession, the total costs at Nalubaale and Kiira will be approximately UGX 65 billion. This declines over the first five years and levels out at approximately UGX 50 billion in the second half of the concession period. As an element of consumer tariffs, the decline is more marked due to consumption growth – the average charge to customers for power from these assets starts at around 50 UGX/kWh and declines by approximately 50 percent by 2016.

A large portion of costs is denominated in US dollars. In fact, everything except operating costs is indexed to the dollar in the proposed regulations. This means that costs are very sensitive to devaluation of the currency. The base case has assumed an annual devaluation of 14.5 percent - consistent with trends over the past three years. If devaluation is significantly different from this, the cumulative impact on generation costs at Nalubaale and Kiira will be large.

Other significant cost sensitivities relate to the lease fee and inflation. Since a large portion of the lease fee is made up of interest payments on UEB Generation's debt, the proposed capital restructuring of UEB Generation will have a significant impact on costs. While no details of the effect on loan obligations have been made available to us, we have seen that reducing the interest payments by 50 percent will reduce costs by an average of 19 percent over the period. The effect will be particularly strong in the early years of the concession.

It is noteworthy that the costs are not particularly sensitive to Genco's rate of return. This is because new investment is expected to be small, and so Genco's return makes up less than 10 percent of the total costs.

## 5.2 Risk transfer

Risk transfer is embodied in the contractual arrangements and price mechanisms. The proposed system comprises a concession (lease of assets with the responsibility for new investment), a capacity price for capacity made available, and periodic adjustments for exchange rates, inflation and investment.

The main risks present in the business relate to investment risk, foreign exchange rates, inflation, operating costs, plant availability, domestic sales and exports, transmission outages and political risks (in relation to policy on the lease fee). Of these risks, the most significant are those relating to foreign exchange, the lease fee, inflation and exports.

All risks except those relating to operating costs, availability, network outages and export price are transferred to consumers. Operating costs and availability remain with Genco, and Transco bears risks relating to export price and network outages (if appropriate provisions are made for this in the contract between Transco and Disco). It should be noted that Transco's incentives relating to exports are not aligned with those of consumers. The latter benefit from exports at any price, whereas Transco only benefits if export prices are above a certain level.

Alternative risk transfer arrangements can be embodied in different contractual arrangements and different price structures and adjustment mechanisms.

The principal alternative contractual arrangements are a management contract and asset privatisation. A management contract would be very similar to the current arrangements, with the only difference relating to the source and cost of capital for new investment. Since new investment is relatively minor, this will not have a large impact on prices. Privatisation would have the effect of expressing many of the cost of risks in the privatisation price. As a result, the costs would largely be borne by the Government rather than consumers. Such an arrangement would allow Government to allocate more risks to Genco than under the current arrangement without leading to significantly higher prices. It may mean, however, that privatisation revenues do not match UEB's existing debt obligations.

The current price structure is essentially a take-or-pay arrangement, independent of actual volume of power or energy delivered. The alternative would be a unit price based on maximum demand, energy or a combination. This would impose volume risk on Genco, as in fact occurs with the distribution company. There are two difficulties with such a system. Firstly, since the lease fee makes up such a large portion of costs, the volume risk would be large and difficult to compensate through an increased rate of return. Such a pricing system would have to be accompanied by the lease fee being structured as a unit charge. Secondly, there would be a conflict from 2005 once Bujagali comes on line. Since Bujagali is a take-or-pay contract, Transco would prefer to take power from Bujagali rather than pay a marginal price to Genco. Given the excess capacity from 2005, the volume risk for Genco would be extremely high.

Finally, the price adjustment mechanism transfers risks related to foreign exchange, inflation and investment. The current system transfers 100 percent of all these risks, with a proposed change in the way investment risks are handled from 2005. Alternative systems, such as use of a reduced adjustment factor, a sliding scale or an adjustment band, would share risks between Genco and consumers. Such an approach could be used in conjunction with asset privatisation, and would allocate the costs of risks among the Government (via the privatisation price), investors (through their expose to a portion of risks) and consumers (through the risks that are transferred by the adjustment mechanism).

## Annex A: Sensitivity analysis

This chapter will discuss the effects of changes on key parameters on the cost of generation at Nalubaale and Kiira. The key parameters are:

- Ugandan inflation;
- Currency devaluation;
- Lease fee;
- Genco's rate of return;
- Hydro discharge; and
- Ugandan demand.

The base case is reported in previous chapter. Here the sensitivity of the unit cost to changes in the key parameters is analysed. The unit cost of Bujagali is not included, thus the unit cost here refers to the contribution of power supply cost of Nalubaale and Kiira to the total average unit cost of power charged to end-users, i.e. a unit cost calculated as follows:

$$\text{Unit cost} = \frac{\text{Total cost of generation from Nalubaale and Kiira}}{\text{Ugandan Sales + Exports}}$$

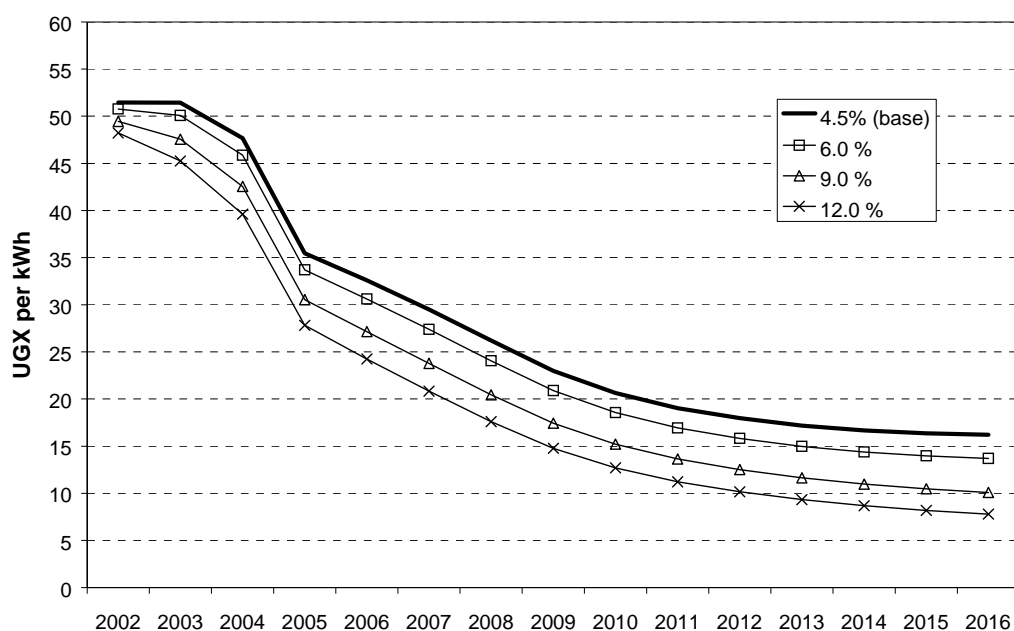
It should be noted that this result gives only a portion of the price that end-users will pay. In addition, they will pay for the costs of Bujagali as well as transmission and distribution costs.

### A1 Ugandan inflation

Inflation will influence the real costs of generation at Nalubaale and Kiira. This is because certain parameters are not influenced by inflation, including depreciation, interest payments on debt and return on assets. However, it should be noted that inflation will have an indirect effect on costs through currency devaluation – a higher inflation rate will tend to cause greater devaluation. We have included this effect in our analysis and it tends to counter-act the effect of inflation.

The effect on costs is presented in Figure A. 1. Much of the effect is caused by the effect that inflation has on depreciation of assets.

Figure A. 1      Sensitivity of unit cost to inflation (real terms)



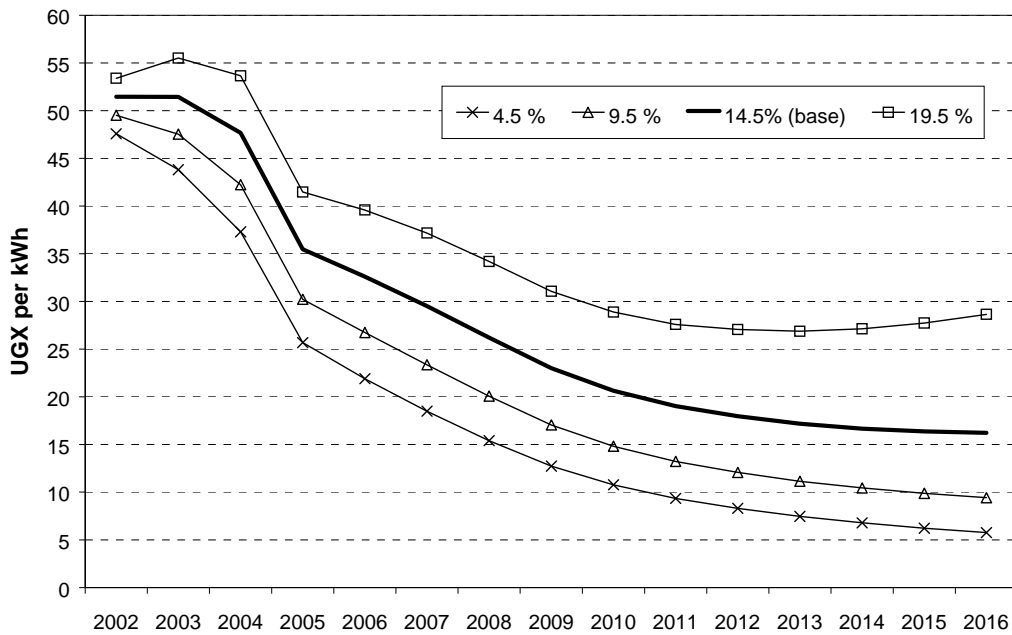
## A.2 Currency devaluation

A number of costs are expressed in dollar terms, and so sensitive to currency devaluation. These foreign currency denominated costs are:

- **Lease fee** – given that UEB Generation’s loans are in foreign currency terms, it seems likely that the Government of Uganda will set the lease fee in dollar terms
- **Investment** – new investment will be denominated in foreign currency, and so Genco’s depreciation and return allowances will be sensitive to exchange rates.

As shown in Figure A. 2, annual devaluation of the shilling increases the costs of Nalubaale and Kiira. Figure A. 2 shows the estimated sensitivity of the unit cost of generation at Nalubaale and Kiira to an annual devaluation of UGX of 4.5, 9.5, 14.5 (Base) and 19.5 percent. Over the past few years, the Ugandan shilling has depreciated at a rate of approximately 15 percent per annum. Should the rate of devaluation increase above this, the effects on the costs of power are likely to be extremely high. As was discussed in section 2.3, the impact on meeting Bujagali payments is even higher.

Figure A. 2 Sensitivity of unit cost of generation to devaluation (real terms)



### A.3 Changes in lease fee

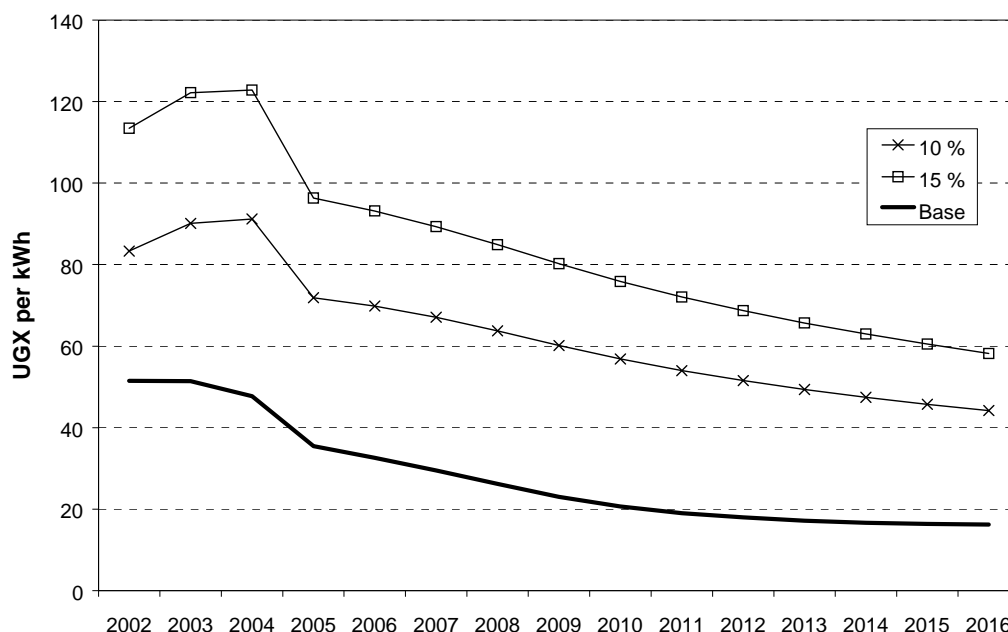
The lease fee contributes the larger portion of Genco's costs in the base case. From this it is obvious that changes in the lease fee may have a profound impact on the total costs and revenue requirements. Three changes or alternative structures of the lease fee are reported below:

- Basing the lease fee on a return on UEB Generation's assets rather than debt servicing costs:
- Changing the current proposed lease fee by  $\pm 10$  percent; and
- Having a fixed annual lease fee, rather than allowing it to decline over time.

#### Return instead of interest obligation

An alternative, to include the interest expenses of UEB in the lease fee, would be to impose a return requirement on UEB. The return on capital required by the Government should in that case replace the interest expenses. The sensitivity results regarding the rate of return are reported in Figure A. 3 below.

Figure A. 3 Sensitivity to replacing interest obligation by return requirement in lease fee (real terms)



The requirement of 10 percent return on UEB assets will significantly increase the total cost of generation at Nalubaale. Setting the return requirement to 15<sup>8</sup> percent will more than double the total costs of generation at Nalubaale and Kiira. This indicates the significance of the Government's choice of model for the lease fee.

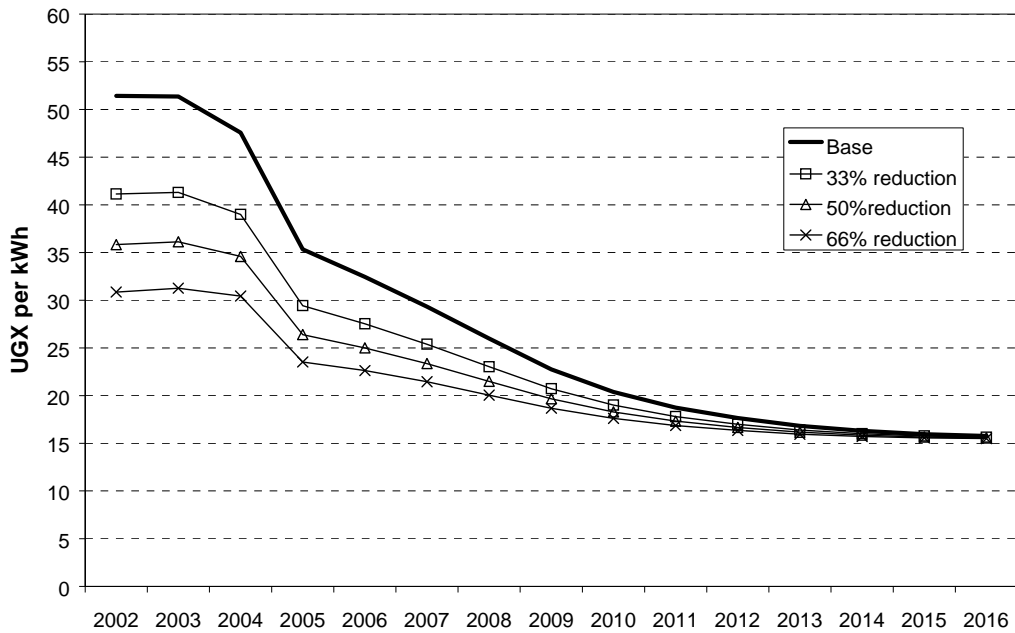
The return requirements mentioned above would induce large surplus revenues to the Government. This is not the objective of the lease. The Government has stated that it will prioritise reduced prices rather than positive revenue. Assuming the Government is committed to this, the risk will be significantly reduced.

### Reduced lease fee

Debt restructuring will significantly impact the level of the lease fee. We test here the case of a 33 percent, 50 percent and 66 percent reduction in the interest obligations contained in the lease fee. Interest payments initially make up over 50 percent of the total lease fee, and thereafter decline in significance over time. Consequently, debt restructuring has a larger effect in the first five years of the concession.

<sup>8</sup> 15 percent is arbitrarily chosen. The Genco's rate of return is 20 percent.

Figure A. 4 Sensitivity of unit cost of generation to changes interest obligations included in lease fee (real terms)



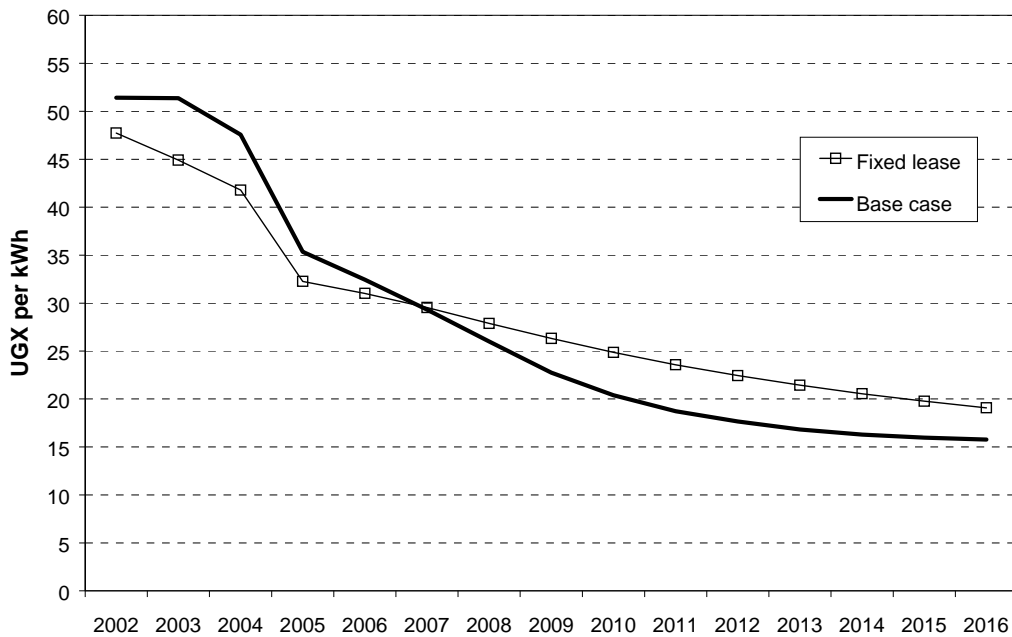
### Fixed lease fee

To induce more stability in the total costs, a fixed lease fee over the period may be used. This can be illustrated by spreading the total lease fee equally over the years and accounting for discount rates<sup>9</sup>. This alternative will give a more stable cost of generation, as shown in Figure A. 5. The downward sloping unit cost schedule is caused by the increase in demand, while the total costs are relatively stable.

It should be noted that the use of a fixed lease fee would not match UEB's debt servicing obligations in the early years. While we have reflected the costs of any bridging financing in the calculations, a limitation to a fixed-lease system may be constraints on bridging finance.

<sup>9</sup> We calculate the annual lease fee as the amortisation of the present value of original lease payments. This takes into account the cost of capital, using a 10 percent discount rate.

Figure A. 5 Fixed lease fee (real terms)



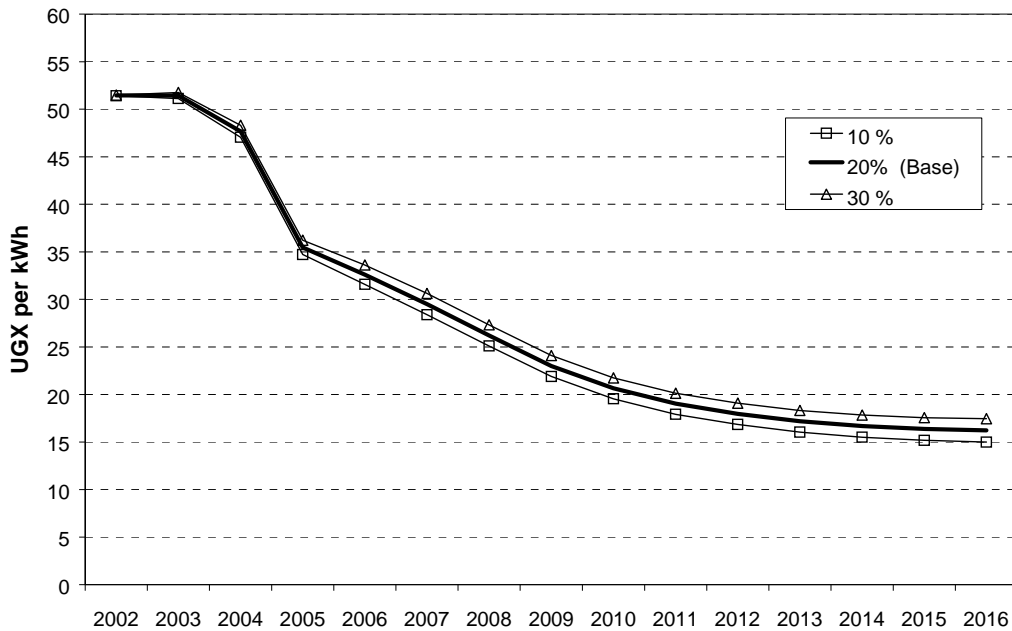
## A.4 Return on Genco's investments

In the proposed privatisation procedures it is likely that Genco's rate of return is made a bidding factor. Thus it is relevant to look closer at the Genco's rate of return on investments, and how a shift in this will effect the total cost of generation. As shown in Figure A. 6, a 10 percent increase or reduction will only slightly effect the unit cost of generation, and mostly towards the end of the period analysed. The two reasons for this are related to Genco's assets:

- Genco will only own a small portion of the total assets, and
- Genco's assets will increase over the period, starting at zero in 2002.

A change in rate of return on a small asset base will give a small change in costs, The larger portion of generation costs stem from the lease fee. Secondly the increased effect over time, is caused by the increase in the Genco's asset base.

Figure A. 6 Sensitivity of unit cost of generation to changes in the Genco's return on investments (real terms)



## A.5 Hydro discharge

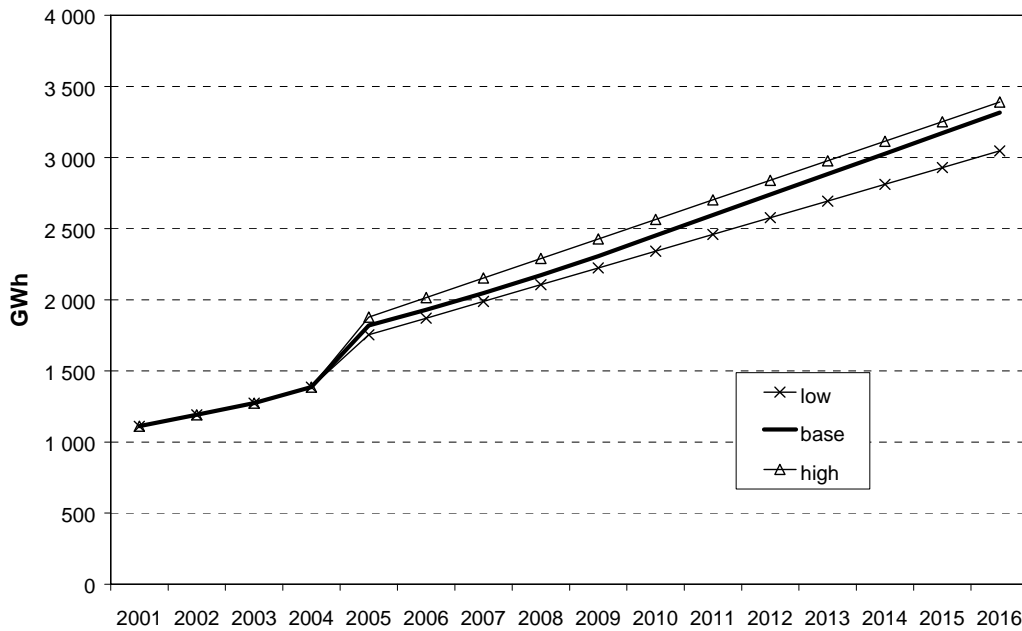
Changes in the hydro discharge have no impact on total annual costs of Kiira and Nalubaale generation, but may influence the level of demand that is served. After 2005, this constraint is lifted due to additional capacity at Bujagali, and hence there is no medium- to long-term impact on the unit cost of generation.

## A.6 Ugandan demand

We have examined three demand scenarios based on the revised forecasts produced by Electricité de France (EdF) in 2000.

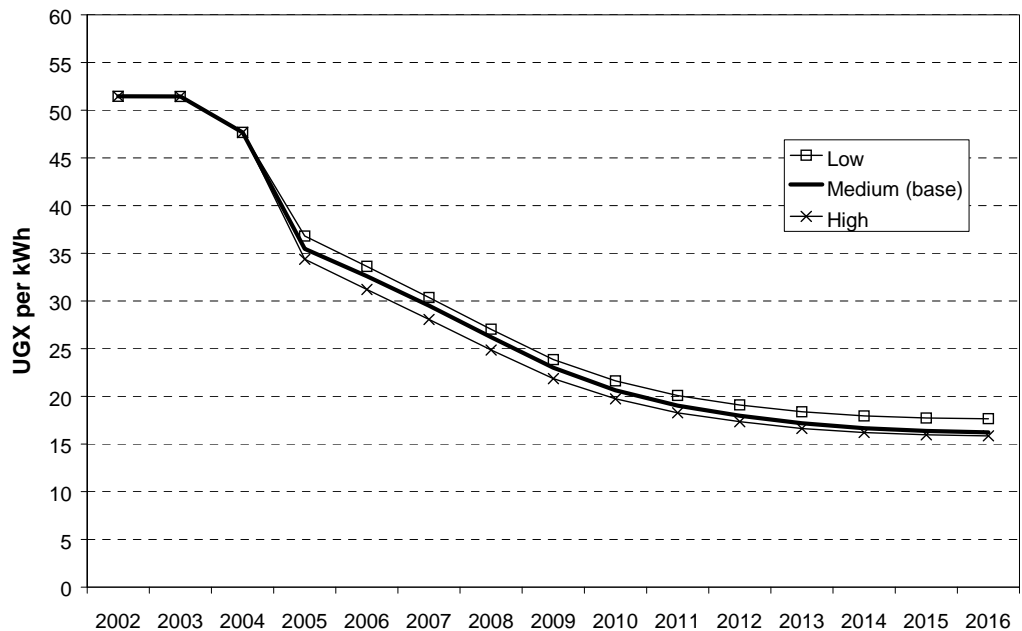
The high and low demand scenarios represent relatively small changes in total demand. Demands are constrained before 2005 and at the end of the period, and changes in unconstrained demand will obviously not have an effect on actual demand in these periods. In 2005 and the following years the constraints are lifted due to more production capacity coming on stream with Bujagali. This is illustrated in Figure A. 7 below.

Figure A. 7 Total demand (including exports)



Changes in demand will obviously not change the annual total costs of generation as long as extra investments or operation expenses are not induced.

Figure A. 8 Sensitivity of unit cost to changes in demand projection (real terms)



Change in demand does not have a strong impact on the unit costs either, as shown in Figure A. 8. The findings can be summarised as follows:

- Before 2005, there is no effect due to constrained demand;
- Some effect is seen after 2005 when constraints are lifted; and

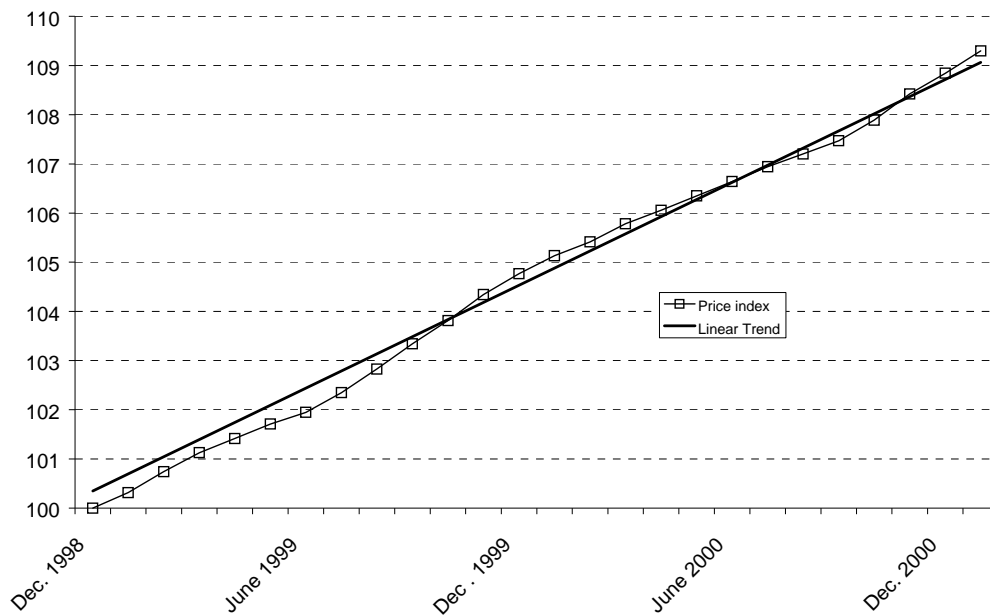
- After 2012 the high scenario will be constrained and thus have little impact on realised demand.

The general conclusion is that average unit cost of power supply is not particularly sensitive to changes in demand.

## Annex B: Ugandan inflation and devaluation trends

The diagram below gives the trend for Ugandan inflation based on monthly data over the two last years. The data are collected from Ugandan Bureau of Statistics and Bank of Uganda. The underlying inflation index excludes the price of foodstuffs, which exhibit seasonal variations.

Figure B 1 *Ugandan underlying inflation index*



Below is also provided a diagram illustrating the trend in depreciation of Ugandan shilling over the two last years. This is also based on monthly data from Bank of Uganda and Ugandan Bureau of Statistics.

Figure B 2 Ugandan shilling/US dollar exchange rate

