# The Bujagali Power Purchase Agreement – an Independent Review

A Study of Techno-Economic Aspects of the Power Purchase Agreement of the Bujagali Hydroelectric Project in Uganda

By Prayas, Energy Group, Pune, India

for International Rivers Network

International Rivers Network
1847 Berkeley Way
Berkeley, CA 94703, USA
irn@irn.org, www.irn.org

20 November 2002

## Preface and summary

The World Bank's Bujagali dam project in Uganda is excessively expensive. The Power Purchase Agreement of the private project is not in line with international standards, and entails massive extra costs for Uganda. The World Bank has given poor advice to the Ugandan government, and has misled the public about the cost of the project. These are the main conclusions of the following review of key project contracts by Prayas Energy Group on behalf of International Rivers Network.

Bujagali is one of the most controversial dam projects in recent years. The 200 MW hydropower project on the Victoria Nile in Uganda is the largest private power project in Sub-Saharan Africa, and the largest private investment in East Africa. It is being developed by the US-based AES Corporation, the world's largest private power producer. South Africa's state-owned power utility, Eskom, is presently considering investing in Bujagali as a joint-venture partner with AES.

Since December 2001, the World Bank Group, the African Development Bank, and public financial institutions from Finland, the Netherlands, Norway, Sweden and Switzerland have approved funding for the project. A guarantee from the World Bank's Multilateral Investment Guarantee Agency is still pending. A number of other financial institutions have declined involvement in the project. In June 2002, the Inspection Panel, the World Bank's independent investigative unit, found that the project violated five Bank policies, including those on involuntary resettlement and environmental impact assessment. In July 2002, serious corruption allegations put all funding for Bujagali on hold. Veidekke, the main civil engineering contractor of the Bujagali consortium, subsequently withdrew from the construction site.

Non-governmental organizations, including Uganda's National Association of Professional Environmentalists (NAPE) and International Rivers Network (IRN), have for many years criticized the Bujagali project's lack of transparency, accountability and consultation. They have also exposed serious economic, social and environmental problems. Specifically, NGOs pointed out that no alternative options to Bujagali were ever seriously considered, that the project was not based on international competitive bidding, and that the World Bank's economic analysis of the project was over-optimistic and contradictory in important aspects.

For many years, NGOs have called for the public release of Bujagali's Power Purchase Agreement (PPA) and Economic Review. As the key project contract, the PPA defines the rights and obligations of the private project sponsor and the Ugandan government over the 30-year lifetime of the contract. Access to this document would enable civil society to discuss Bujagali's long-term financial implications for Ugandan citizens. The World Bank, AES and the Ugandan government have never agreed to release the Bujagali PPA. In violation of its own disclosure policy, the World Bank has even refused to provide access to the project's Economic Review.

On 12 November, 2002, the Uganda High Court ruled in a case submitted by the Ugandan NGO Greenwatch that the Bujagali PPA must be released to the public. This is a ground-breaking judgment which strengthens the claims of civil society for transparency and accountability in economic decision-making internationally.

IRN has commissioned Prayas Energy Group of India to analyze the Bujagali PPA and its implications for Uganda. Prayas used an innovative methodology to analyze in detail the complicated contract, and its financial implications for Uganda. The Prayas review explains the main features of the PPA (section 1 of this paper), and the complex definition of costs and tariffs (section 2). The paper provides a detailed critique of the project contracts (section 3), and of the World Bank's role in the Bujagali project (section 4). Section 5 summarizes the conclusions of the Prayas review. Annex II compares the cost of the Bujagali project with a hydropower scheme with similar features in India.

The main findings of the review are summarized in sections 3.7., 4 and 5 of this paper. They document the following:

1) The capital cost of the Bujagali project is excessively high. The analysis in Annex II shows that a comparable project with similar features in India has twice the generating capacity of Bujagali, but will cost less than the AES project.

2) On top of the high capital cost, the Bujagali PPA contains a number of unusual requirements which are detrimental to Uganda. The Ugandan government will have to make yearly payments of up to $132 million for the project (and not $111 million as claimed by the PPA and the World Bank). A PPA and capital cost which are in line with international standards would reduce Uganda's yearly payment obligations for Bujagali by about $40 million initially, and by an average $20 million over the lifetime of the project. This would result in savings with a net present value of $280 million for Uganda. If private developers are only prepared to invest in Uganda under the excessive terms laid down in the Bujagali PPA, the country would be much better off developing its energy resources through the state.

3) The World Bank provided poor advice to Uganda's government on how to negotiate the contract for this private power project. In addition, the Bank published misleading or wrong information on important issues.

Based on Prayas' analysis and critique of the Bujagali PPA, NAPE and IRN conclude the following:

1) The Bujagali project, including the project's PPA, is fundamentally flawed and not in the best interest of the Ugandan people. Uganda's government and the Uganda Electricity Board should cancel the project contracts, and the World Bank should cancel its funding of the project. (Under the project's Implementation Agreement of 1999, the sponsor undertook to close the financial package for the

project within one year. The AES Corporation has still not managed to reach financial closure, giving Uganda the right to cancel the project.)

2) A balanced and participatory process should be launched immediately to assess all available options to bridge the gap between Uganda's energy needs and supply, including the promising potential of cheap geothermal power and the Karuma hydropower project. The African Development Bank's Uganda Alternative Energy Resource Assessment and Utilitzation Study should proceed without further delay. NAPE and IRN are prepared to assist Uganda's authorities in this process.

3) The World Bank Board of Directors should investigate the poor quality of the Bank's assistance to the Ugandan government during the negotiation of the Bujagali contract, the Bank's failure to insist on a competitive bidding process and adequate standards of accountability, and the failure to detect corruption in the Bujagali project. The Board should initiate a participatory review of the Bank's anti-corruption policies.

4) The Bank's draft Water Resources Sector Strategy (WRSS) misrepresents the findings and ignores the recommendations of the World Commission on Dams (WCD). It instead puts supposed "high risk/high reward" projects like Bujagali at the core of the Bank's future water sector strategy. The Bujagali experience confirms that such an approach results in massive delays and conflicts, and does not provide a solution to the water and energy needs of the poor. The World Bank Board of Directors should reject the draft WRSS, and should base the Bank's future water sector strategy on the WCD's findings and recommendations.

5) Transparency and accountability are basic preconditions of good governance and sound economic development. The review by Prayas Energy Group demonstrates that this rule also applies to Power Purchase Agreements. The recent decision of the Uganda High Court supports the claims of civil society for accountability in economic decision-making and World Bank projects. Governments should no longer negotiate expensive long-term contracts without public debate and scrutiny, and the World Bank should not fund any future power projects based on confidential PPAs.

NAPE and IRN hope that this independent review will allow an informed public debate in Uganda and internationally about the cost of the Bujagali dam and the role of the World Bank and other financial institutions in private power projects.

Peter Bosshard
International Rivers Network, USA

Frank Muramuzi
National Association of Professional Environmentalists, Uganda

## About Prayas, Energy Group

Prayas is a non-governmental organization (NGO) working on the four substantive themes of Health, Energy, Resources & Livelihoods, and Learning & Parenthood. The Prayas, Energy Group focuses on analysis, training and advocacy relating to power policy issues. Past work of the Energy Group includes the analysis of the power purchase agreement between the Enron-promoted Dabhol Power Company and a state power utility in India, the preparation of an Integrated Resource Plan (IRP) for the state of Maharashtra, and a critique of the World Bank's lending and activities relating to the power sector in India. In recent years, the Energy Group has been working on issues relating to power sector reforms and regulation. All publications of Prayas, Energy Group are available on the website www.prayaspune.org.

Prayas, Energy Group Research Team:
Girish Sant, Shantanu Dixit, Subodh Wagle and N. Sreekumar

Contacts:
Prayas, Amrita Clinic, Athawale Corner, Karve Road Corner, Pune 411 004, India
Tel. +91 20 567 6742 Tel./ Fax +91 20 542 0337 Email: prayas@vsnl.com

---

## About International Rivers Network

International Rivers Network (IRN) supports local communities and civil society groups working to protect their rivers and watersheds. IRN encourages equitable and sustainable methods of water and energy sector development, and promotes public participation and transparency in decision-making. International Rivers Network has monitored the development of the Bujagali dam for many years, and supports the quest of Ugandan NGOs for an informed public debate about this project. IRN representatives have visited Uganda, and the project site, several times, and have published a number of reports about the Bujagali project. A recent IRN report also analyzes the international experience with private power projects and their Power Purchase Agreements.

Contacts:
International Rivers Network, 1847 Berkeley Way, Berkeley, CA 94703, USA,
irn@irn.org, www.irn.org (general information about IRN),
http://www.irn.org/programs/bujagali/ (reports on Bujagali).

---

The independent review of the Bujagali PPA was made possible through a generous grant of the German Grassroots Foundation.

---

## Glossary

| | |
|---|---|
| AES | AES Corporation, registered in the USA |
| AESNP | AES Nile Power Ltd., the company promoted by AES Corporation for the Bujagali project. It is registered in Uganda. |
| AEUDC | Allowance for equity used during construction |
| EPC | Engineering, Procurement and Construction |
| GoU | Government of Uganda |
| IA | Implementation Agreement between AESNP and GoU, dated 8 December 1999 |
| IDC | Interest during construction |
| Mn | Million |
| MU | Million units (kWh) of electric energy |
| MW | Megawatt, unit of electric power producing capacity (1,000 Kilowatt) |
| PAD | Project Appraisal Document of the World Bank (Report No.22963-UG), dated 14 November 2001 |
| PLF | Plant Load Factor, ratio of actual generation from the plant to maximum possible generation (assuming the entire capacity to be available throughout the year) |
| PPA | Power Purchase Agreement between AESNP and UEB, dated 8 December 1999 |
| TPC | Tariff Project Cost |
| UEB | Uganda Electricity Board, the Ugandan utility which has signed the PPA with AESNP. Since the signing of the PPA, UEB has been restructured, and the Uganda Electricity Transmission Corporation (UETC) has assumed the PPA liabilities and rights. |
| USh | Ugandan Shilling |
| WB | World Bank |

## Contents


| | | |
|---|---|---|
| | Preface and summary | 2 |
| 1) | The main features of the project and project agreements | 8 |
| 2) | The structure of costs and tariffs in the PPA | 16 |
| 3) | Analysis and critique of the PPA | 21 |
| 4) | The World Bank's role: inadequate analysis and misinterpretation | 27 |
| 5) | Conclusions | 29 |
| 6) | Acknowledgements | 30 |
| 7) | Bibliography | 30 |
| 8) | Annex I: Assumptions for the base case | 31 |
| 9) | Annex II: The high capital cost of the Bujagali project | 32 |

# The Bujagali Power Purchase Agreement – an Independent Review

## 1. The main features of the project and project agreements (IA and PPA)

The Bujagali Hydroelectric Project is a private power project in Uganda. It is being developed by AES Nile Power Ltd. (AESNP) on a "build-own-operate and transfer" (BOOT) basis. AESNP has entered into two main agreements with Ugandan government agencies. These are the "Implementation Agreement" (IA) with the Government of Uganda (GoU), and the "Power Purchase Agreement" (PPA) with the Uganda Electricity Board (UEB). This report primarily analyzes the PPA of 8 December 1999, a copy of which has been made available to Prayas Energy Group. Where relevant, provisions of the Implementation Agreement are also introduced.

References in brackets (e.g. IA S. 2.1) refer to the sections of the project documents. Technical terms in capitals in this text refer to terms defined in the legal documents. A scanned version of the PPA is available on http://irn.org/programs/bujagali/bujagalippa.pdf .

### 1.1. The capacity of the power plant:

The proposed hydropower complex will have a capacity of 200 MW (50 MW x 4 units). UEB has an option to ask AESNP to increase this capacity by another 50 MW. UEB has to instruct AESNP of an increase in capacity within 18 months from the start of construction (Financial Closure). If UEB elects to increase the capacity, the basic cost of the project increases by $24.5 million (with an associated increase in soft costs, i.e. interest during construction, financing cost etc.). For the purpose of this report, it is assumed that UEB will not exercise this option of increasing the capacity. The construction of nearly 100 km of transmission line, connecting the Bujagali powerhouse to the UEB grid, is also a part of this project. The transmission line, unlike the power plant complex, will be handed over to UEB for maintenance and operation once it is constructed.

### 1.2. BOOT structure and right of first refusal:

AESNP will construct the plant and operate it for 30 years. At the end of this period, the plant will be handed over to the Government of Uganda at a nominal cost of $1/-. If the government decides to hand over the plant (either for operation and maintenance or through sale) to a third party, AESNP has a "right of first refusal". This means that AESNP has a right to take over the plant on the same terms and conditions which are offered to the third party. (IA S. 2.1)

### 1.3. Generation of electricity from the power plant:

The main responsibility of AESNP is to construct and operate the power plant. Actual generation from the plant will depend on the hydrological conditions as well as dispatch (generation) instructions by UEB. There is considerable dispute about the hydrological conditions of the Victoria Nile and their impact on the electricity generation potential. The World Bank's Project Appraisal Document (PAD) for Bujagali has considered a generation of around 1414 MU per year. This would result in a plant load factor of 80%. (PAD Pg. 56)[1]

1.4. Construction and financing:

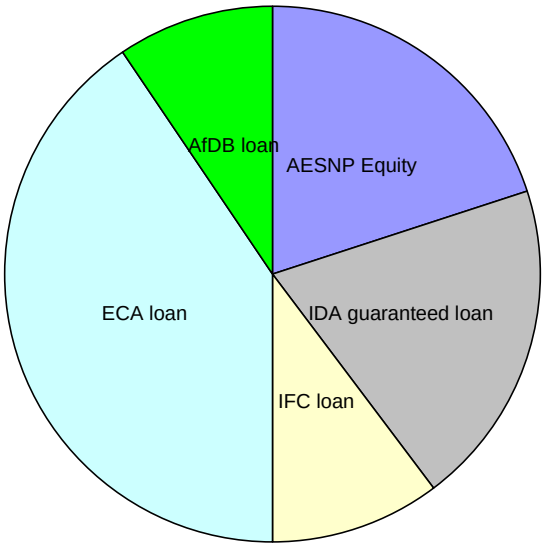
AESNP has agreed to construct the dam, related civil works and the power plant within 44 months from the date of Financial Closure. The PPA was signed in December 1999, and Financial Closure was expected within a year from the signing of the contract. As Financial Closure has still not been announced, the plant is unlikely to be operational before 2006. AESNP will be responsible for raising the finances for the construction of the project.

The IA and PPA do not quantify several components of the project costs. As a result, the project cost can only be estimated. The World Bank PAD estimates the total cost of the project (including EPC, IDC and financing costs) at around $580 million. This cost is expected to be financed on a debt:equity ratio of 80:20. Figure 1 shows the financing pattern of the project as reflected in the World Bank's appraisal. Nearly the entire debt component is either funded or guaranteed by export credit agencies, the World Bank Group and the African Development Bank. The lack of any debt financing without the support of such multilateral or bilateral financing institutions reflects the poor creditworthiness of the buyer, i.e. UEB and the government of Uganda. The Implementation Agreement mentions that at the time of its signing (December 1999), the parties had anticipated that the World Bank (excluding IFC) would not participate in financing the project either directly or through guarantee programs (IA S. 2.4, b). The IA did not bar the possibility of World Bank financing for the project and in fact, as shown in Figure 1, the project now envisages substantial World Bank support.

The IA and the PPA do not specify either the source or the cost of financing. All costs of financing are treated as pass through costs, i.e. UEB has to pay interest on debt at actual, without having any control or cap on the financing terms. UEB, the sole buyer, is bound to bear the brunt of the financing cost in the tariff.

[1] The PAD indicates that the generation at Bujagali would be in the range of 1,000 to 1,500 MU depending on the hydrological assumption. The generation figure used (1414 MU) is close to the higher value.

**Figure 1: The financing of the project**




Another peculiar feature of the PPA is the definition of Financial Closure. Disbursement by any lender of any part of the loan is considered to constitute Financing Closure. Since Rule 144-A financing is available for the project[2], AES could for example easily get a $1 million loan from any associates or friendly lenders in the US and declare this Financial Closure. Such a vague definition of Financial Closure is not a good industry practice. Usually, Financial Closure occurs when all financing and project documents have been executed and all conditions precedent to debt draw-down for funding the construction of the project have been met. An intermittent one-off debt draw-down cannot and should not trigger Financial Closure. In such an event, UEB risks being bound by the terms of the IA / PPA. In this case, the utility would have to move forward with the project or else risk stiff penalties even though it has not endorsed all the project and financing contracts.

1.5. Interim Energy:

The power plant consists of four generating units of 50 MW each. These units will be ready for generation over a period of a few months, prior to the commissioning of the full plant. The PPA provides that energy generated prior to the commercial operation (commissioning) will be purchased by UEB at $0.06 / kWh. The plant's capacity to generate (availability) is treated as generation, irrespective of actual instructions to generate or availability of water for power generation.

Revenue from this sale of interim energy will be first utilized to create a “Liquidity Account” of $20 million (see section 1.7. for explanation). If the revenue from interim

[2] Rule 144 A (USA) allows investors to raise funds without SEC registration. These loans are characterized by high flexibility, low public disclosure, high risks and high returns.

energy generation is more than $20 million, the EPC contractor will be eligible for an incentive at the rate of $0.0175 / kWh, up to a maximum of $3 million.

The PPA assumes that the net Interim Energy revenue, after accounting for the two payments mentioned above, will be at least $16 million (i.e. that total interim energy revenues will amount to at least $39 million). If this is not the case, the "Tariff Project Cost" (TPC as explained in section 2.1.) will be increased by the amount of the deficit. The Maximum Capacity Payment will also increase accordingly. This implies that the Tariff Project Cost, and the capacity payments after the commercial operations date, will increase if the gross Interim Energy Payment is less than $39 million (i.e. if pre-commercial operation generation is less than 650 MU, equivalent to five months of plant operation).

Hence, if the net Interim Energy (IE) payment is for example $15 million, AESNP will have $15 million at its disposal but the TPC will increase by $1 million. This contradicts the first statement in the relevant section (PPA, Annex D Section 3.7 (d)) which stipulates that AESNP will use all net IE payments to "fund and reduce the TPC". Hence this is going to be a contentious issue, with one interpretation being that AESNP will take out $16 million at this point. If this interpretation holds, the internal rate of return of AESNP will increase by about 0.9%.

### 1.6. Financing Bond and Abandonment Bond:

As a measure of AESNP's commitment to the project, AESNP has to provide two bonds, a Financing Bond and an Abandonment Bond, in favor of GoU / UEB. The Financing Bond is worth $7 million. If AESNP is unable to achieve Financial Closure within one year from the date of signing the PPA, the government can cash in this bond. The Abandonment Bond is worth $12.5 million. If AESNP abandons the construction of the project after Financial Closure, the government / UEB can cash in the Abandonment Bond. Any encashment of these bonds is subject to several conditions, and remains a remote possibility.

### 1.7. Liquidity Facility Agreement:

According to the provisions of the IA and PPA, UEB, AESNP and a trustee bank will enter into a separate "Liquidity Facility Agreement". According to this agreement, UEB has to maintain at least $20 million (about two months of capacity payment under the PPA) in a separate bank account until the entire debt of the project is repaid. This will be named the Bujagali Liquidity Account. As mentioned earlier, the initial amount will come from the payments made by UEB towards Interim Energy payments (from plant availability before the commercial operations date). The trustee bank will have the sole right to withdraw this amount. AESNP can ask the trustee bank to pay required Dollars from this account if either AESNP is unable to convert Uganda Shillings into US Dollars, or if UEB fails to pay the full Capacity Payment by the due date. If the balance in this Liquidity Account falls below the required amount at any time, UEB has to replenish the

account to the required amount within 30 days. In case the Liquidity Account does not have $15 million for 60 consecutive days, UEB has to ensure that all payments it receives through export sales are directly deposited into this account. In summary, the Bujagali Liquidity Account serves as a funded escrow account. After the entire debt of the project is repaid, the money in the Liquidity Facility will go to UEB.

1.8. Debt Service Reserve Account:

According to the project agreements, a separate Debt Service Reserve Account will be opened, and a trustee bank will operate it. It is expected that this account will always have hard currency sufficient to cover debt repayments (principle and interest) equivalent to six months of payment obligations. In case of delay or payment default by UEB, AESNP can withdraw money from this account. About $33 million will need to be deposited in this account. This amount is part of project cost, and will be funded through debt and equity.

1.9. Government Guarantee:

Through the guarantee agreement in the IA, the government of Uganda guarantees all payments due by UEB. In case of payment default by UEB, GoU will immediately pay AESNP any unpaid amounts. This guarantee will be applicable as long as any part of the project debt remains to be repaid or until the buyer utility obtains an "investment grade" rating from an internationally reputed credit rating agency.

1.10. Conditions imposed on the government:

Through the IA, the government accepts certain obligations. Two of these obligations merit special attention. First, the IA requires GoU to prepare and complete an implementation plan for either the privatization or capitalization of UEB, and the commencement of such an implementation plan. This first provision shows a clear belief that privatization is essential for an improvement in performance of the sector. Despite privatization, the GoU will however not be absolved of its liability under the guarantee to AESNP. The usual practice is to pass on the past liabilities (such as payments under the PPA) to the government through the state-owned transmission corporation.

The second obligation relates to new PPAs. According to the IA, GoU / UEB are prevented from entering into any new PPAs or IAs for other projects until AESNP attains Financial Closure, unless they can expressly and independently evidence that such new projects are financially sustainable without affecting GoU / UEB's ability to sustain the Bujagali project. This provision makes financial sense[3]. However, preventing UEB from signing more PPAs could have harmful consequences for UEB. In the event of Political Force Majeure or any dispute between AESNP and UEB/GoU – typically very time-consuming processes –, the government will not be in a position to move forward and

[3] Some developing country power utilities have signed so many PPAs they have been unable to sustain any of them. This has led to disputes between the IPPs and the respective governments.

sign a new PPA. This is extremely risky for UEB and could have serious implications for the future power supply scenario in Uganda.

1.11. Performance guarantees, penalties and bonuses:

AESNP gives certain performance guarantees through the project agreements. In case AESNP is unable to achieve the guaranteed performance, it will have to pay penalties. Similarly, in case the performance is better than the established norms, AESNP is entitled to a bonus. The main parameters for which AESNP has given performance guarantees are the construction period and the availability of the plant. The financial implications of these performance guarantees, penalties and bonuses are elaborated later.

1.12. Tariff:

Annex D of the PPA provides detailed procedures and formulas for computing the Bujagali power tariff. All costs and payments by UEB are denominated in US dollars. The entire risk of exchange rate fluctuations is thus passed on to UEB. The tariff mainly depends on the "Tariff Project Cost" and the project financing (i.e. the proportion of debt, its term and interest). The main components of the "Tariff Project Cost" are:

1) EPC Cost,
2) Non-EPC Costs (i.e. costs of AESNP for project development and management),
3) Interest During Construction,
4) Pass Through Costs (i.e. costs such as customs duties, payment of fees to government authorities etc.),
5) Financing Fees (i.e. fees and commissions paid for raising debt and guarantees etc.), and
6) Debt Service Reserve to be created as explained earlier.

The tariff payable by UEB is termed "Capacity Payment" and is determined on an annual basis. Actual payment has to be made in twelve equal monthly installments, with certain adjustments at the end of the year. Broadly speaking the tariff consists of the repayment of debt (principle and interest), the repayment of equity, the return on equity, and operation and maintenance costs. The entire equity invested by AESNP will be repaid in 30 years in equal installments. Every year AESNP will get a return of 18% on the unpaid equity component. This return on equity (profit) is post tax, i.e. all taxes (e.g. corporate tax) will be an additional component of the Capacity Payment. After debt is repaid (after about 12 years), the UEB payments decrease substantially, and the equity repayment, return on equity and O&M costs remain the only components to be paid.

AESNP will present the bill within five days after end of the month, and UEB is obliged to pay within 45 days. UEB can avail certain small discounts for prompt payment (for example a discount of 0.15% for payment within ten days), and for payment in US Dollars instead of USh (a discount of 0.25%). The Capacity Payment payable by UEB is fixed irrespective of actual generation from the plant and is only subject to AESNP being

able to operate the plant as instructed by UEB (within specified technical limits) and subject to hydrological conditions.

As a consequence, the actual tariff (in US Cents / unit) from the project will be inversely proportional to the power generation from the project. In other words, if power demand in the country (plus power export) is lower than expected, generation from Bujagali may also be lower, leading to a higher tariff. Similarly, if the water flow is lower, generation will be lower, which will lead to a higher tariff.

1.13. Payment deferral:

The PPA allows UEB to defer payments under the following conditions:

(a) A certain portion of the Capacity Payment payable according to Annex D of the PPA can be deferred for the first seven years as long as a Debt Service Coverage Ratio (DSCR) of 1.4 is maintained. DSCR is the ratio of payment to AESNP to the amount payable towards debt repayment and interest. For example, if in a particular year, the actual Capacity Payment is $140 million and the debt and interest repayment is $68 million, UEB can defer payments of $44.8 million {140 –(68 x 1.4)}.

(b) For the first 12 years, UEB can also defer any part of the Capacity Payment above the "Maximum Capacity Payment" (which is specified in Table 4 of Annex D). The estimated values of "Maximum Capacity Payment" given in the PPA range from $100 to 111 million for the first few years. These estimates will however be recalculated at the time of the commercial operation date, based on actual values and terms of debt among other factors. Delay in Financial Closure, Political Force Majeure and Interim Energy Payments below expectations are some of the factors that can increase the Maximum Capacity Payments.

Although the PPA allows deferral of such payments, this comes at a high cost. UEB has to repay the deferred payments at an interest rate of 13% p.a., and for the deferred equity component it has to pay an additional return of 0.6%. Such deferred amounts have to be capitalized and repaid over the remaining term of the PPA (i.e. up to 23 years or 18 years in cases (a) and (b) respectively).

(c) Other situations: A certain deferral is also allowed in the case of Hydrological Force Majeure. If the water flow of the Victoria Nile is less than the assumed base flow (700 cubic meters/sec in 1999, linearly decreasing to 450 cubic meters/sec in 2015), the components of the Capacity Payment corresponding to repayment and return on equity can be deferred. Such a deferral attracts an interest rate of nearly 20% p.a. In such cases the deferral has to be repaid immediately when the water flows return to the assumed discharge.

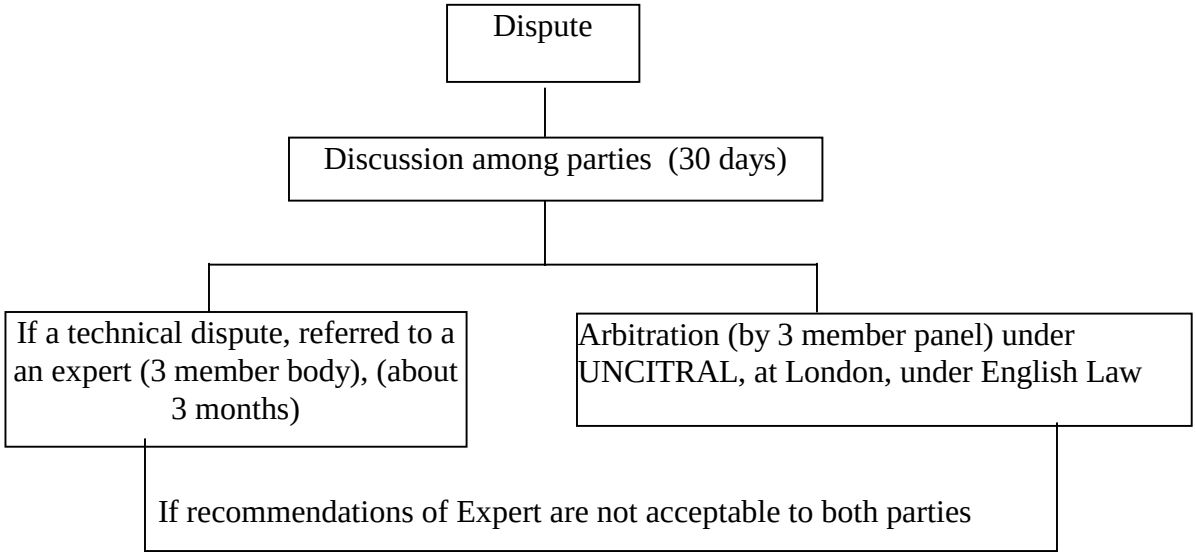
The option of deferral under the Bujagali PPA is prohibitively expensive. The option appears to have been designed to keep UEB out of formally getting into payment default

when full payments cannot be made. As the option of Deferral is too expensive and not desirable, this report does not further consider any deferral scenarios.

1.14. Dispute Resolution:

The PPA and IA provide for an elaborate procedure for the resolution of disputes. After a dispute arises, both parties have a period of 30 days to resolve it by discussion. If the dispute is not resolved and is of a technical nature, the matter is referred to an "Expert". If both parties agree, an Expert will be one person; otherwise it is a body of three people. In the later case, each party appoints one expert, and they together appoint the third person. The resolution of technical disputes is also expected to take place within a set timetable of about three months. If the subject matter of dispute is not technical, or if the recommendations of the "Expert" on a technical matter are not acceptable to both parties, the dispute is resolved through the Arbitration rules of the United Nations Commission on International Trade Law (UNCITRAL). Arbitration would be conducted in London and governed by English law.

**Figure 2: Dispute Resolution Mechanism**




1.15. Termination:

Typical for such IPP agreements, the Bujagali PPA also specifies events under which the contract can be terminated, and the consequences of such termination. Essentially, if the contract is terminated by GoU / UEB without demonstrating a default by AESNP, such an act would attract stiff penalties.

## 2. The structure of costs and tariffs in the PPA

In any power purchase agreement, two parties agree on a number of issues likely to arise over a long period of project development and operation. In order to minimize risks and possibilities of dispute in this period, the PPA attempts to anticipate several possible events and issues (for example changes in costs, taxes, hydrology, war etc.), and contains provisions about how to address the implications of such events. A PPA needs to cast all these possible events, and agreements on how to address them, into a contractual, legally binding language. This makes PPAs, and especially their cost and tariff related provisions, difficult to understand. The Bujagali PPA between AESNP and UEB is no exception to this.

The following section broadly explains the various provisions relating to cost and tariffs in Annex D of the Bujagali PPA. The structure of these provisions is also illustrated in Figures 3 and 4.

### 2.1. Costs:

Figure 3 depicts the cost structure embedded in the PPA. The "Actual Project Cost" consists of the following six main items:

1) Engineering, Procurement and Construction (EPC) cost;
2) Non-EPC costs (i.e. costs of AESNP towards project development and management);
3) Financing Fees (i.e. fees and other associated expenses for raising finances (debt) for the project);
4) Interest During Construction (IDC, i.e. interest to be paid on debt utilized during the project construction. As the repayment of debt begins after the project is completed, interest during construction is added to the debt and repaid over a period after project completion);
5) Pass through costs (i.e. costs incurred by the AESNP towards getting various government approvals, compensation for land etc., which are passed through to UEB);
6) Debt Service Reserve (i.e. a special reserve created to repay the debt).

Out of these six items, all except for the first two (EPC Cost and Non-EPC Costs) are treated at actual. This means that the actual costs incurred by the company are considered for the purpose of the tariff calculation. In case of EPC costs, AESNP and UEB have agreed on an "Estimated EPC Cost" of $330 million. If the actual (Contracted) EPC cost is different from the estimated cost, the difference has to be accounted for. The difference is calculated after some adjustments – for example for the difference between the assumed expenditure profile and timing of expenditure and actual expenditure – have been made. If the Contracted EPC Cost is lower than Estimated EPC Costs, a part of the difference is termed as "Cost Saving", and is added to the "Tariff Project Cost". It is assumed to have been funded through equity. In other words, the "Cost Saving" indicates the benefit of cost reduction given to AESNP.

The logic behind such a provision is that the promoter should have some incentive to reduce costs. The crucial question is what part of the cost reduction is passed on to the buyer, i.e UEB. If the difference mentioned above is less than $10 million, the Cost Saving (for AESNP) is 80% of the difference, and only 20% are passed on to UEB. If the difference is more than $10 million, the difference above this threshold is shared equally. If the difference is for example $15 million, the Cost Saving (i.e. the amount included in the Tariff Project Cost) is $10.5 million, and the benefit to UEB, $4.5 million. As will be shown in section 3.3., due to other peculiar provisions in the PPA (such as AEUDC and the requirement of treating Cost Saving as if it were funded by equity), nearly all the benefit of cost reduction is passed on to AESNP.

Non-EPC Costs are defined in Table 1 of Annex D in Dollars per month. They are subject to certain adjustments for inflation and delays in Financial Closure.

The contracted EPC Costs and Non-ECP Costs together constitute "Gross Contracted Project Cost". If this cost exceeds the estimated contracted project cost, only half of the difference (with a cap of 2.5% of estimated cost) is added to the Tariff Project Cost.

The Actual Project Cost and Cost Saving constitute the "Tariff Project Costs". Certain other costs can also be added to the Tariff Project Cost, depending on the actual circumstances during project development and operation. Examples are costs due to Political Force Majeure, revenues from Interim Energy Sales below target, and the cost of restoration.

AESNP will fund the Tariff Project Cost through its equity and through debt. AESNP has contracted that the debt:equity ratio of the project will be at least 75:25. If AESNP manages to increase the debt component beyond the minimum guaranteed 75%, a part of the increased debt component is considered as funded through equity, as an incentive for AESNP. (Debt is less expensive than equity, so that Capacity Payments will decrease if the equity component is reduced.) This derived debt:equity ratio is termed "Assumed Leverage", and is used to define the equity and debt components for calculating the Capacity Payment.

Assumed Leverage is derived by increasing the equity component by 70% of the difference between the actual and the guaranteed debt percentage of 75%. If for example the actual debt:equity ratio was 80:20, 70% of the 5% difference to the guaranteed equity percentage (of 25%) would be added. This would result in an assumed equity of 23.5%, and an Assumed Leverage of 76.5:23.5.

The component of debt to be included in the Capacity Payment calculations is derived by multiplying the Tariff Project Cost[4] by the ratio of debt in the Assumed Leverage (76.5% in the above case). The equity component to be considered for the Capacity Payment is termed "Aggregate Equity" and consists of the following three sub-components: (a) the

[4] Only for deriving the Equity and Debt component to be considered for Capacity Payments, Tariff Project Cost is considered without including the Cost Saving.

amount derived by applying the ratio of equity in the Assumed Leverage (23.5% in the above case) to the Tariff Project Cost; (b) Cost Saving, which is considered as funded by AESNP equity; and (c) "AEUDC" (allowance for equity used during construction). AEUDC is to account for the lost return on equity during the construction stage, before payments start. AEUDC is to be calculated on Cost Saving equity as well as on equity derived from the Tariff Project Cost at a rate of over 20% per annum. The equity actually invested of $117 million (over the period of project development) thus results in Aggregate Equity of $241 million.

The numbers (in %) shown in the blocks in the schematic diagram of Figure 3 represent the components of a Tariff Project Cost of about $600 million. The Aggregate Equity and Debt derived from this project cost for consideration in the Capacity Payment are also shown.

## 2.2. Tariffs or Capacity Payments:

The Bujagali PPA terms the payments which UEB will make to AESNP "Capacity Payments". As shown in Figure 4, the Capacity Payment consists of six major components. Aggregate Equity is to be repaid in equal installments over the PPA duration of 30 years. A return of 18% p.a. on the outstanding component of the Aggregate Equity is included in the Capacity Payment as "Return on Equity". The repayment of Debt (i.e. Assumed Leverage applied to Tariff Project Cost) and the interest thereon are part of the Capacity Payment on "at actual" interest rates. Apart from these four components, annual Operation and Maintenance costs (about $6.7 million in the year 2006) and certain taxes payable by AESNP are included in the Capacity Payment. The Capacity Payment derived from these six components will be adjusted for some factors such as bonus or penalty payments (e.g. for differences in plant availability) and earnings from the Debt Service Reserve. The annual Capacity Payment thus derived is to be paid in 12 equal monthly installments.

The values shown in Figure 4 represent the composition of the Capacity Payment during the first year.

**Figure 3: Cost structure in the Bujagali PPA**

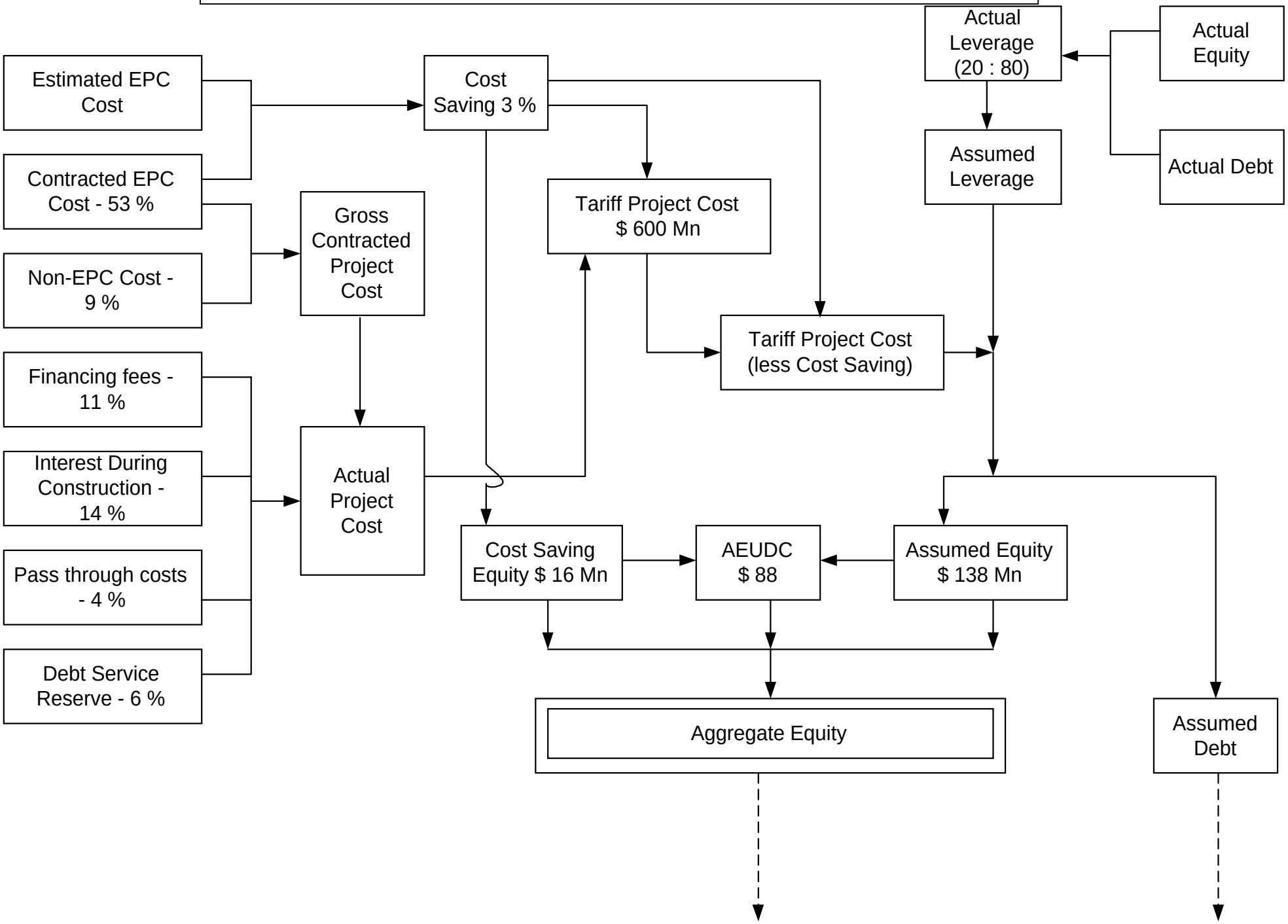
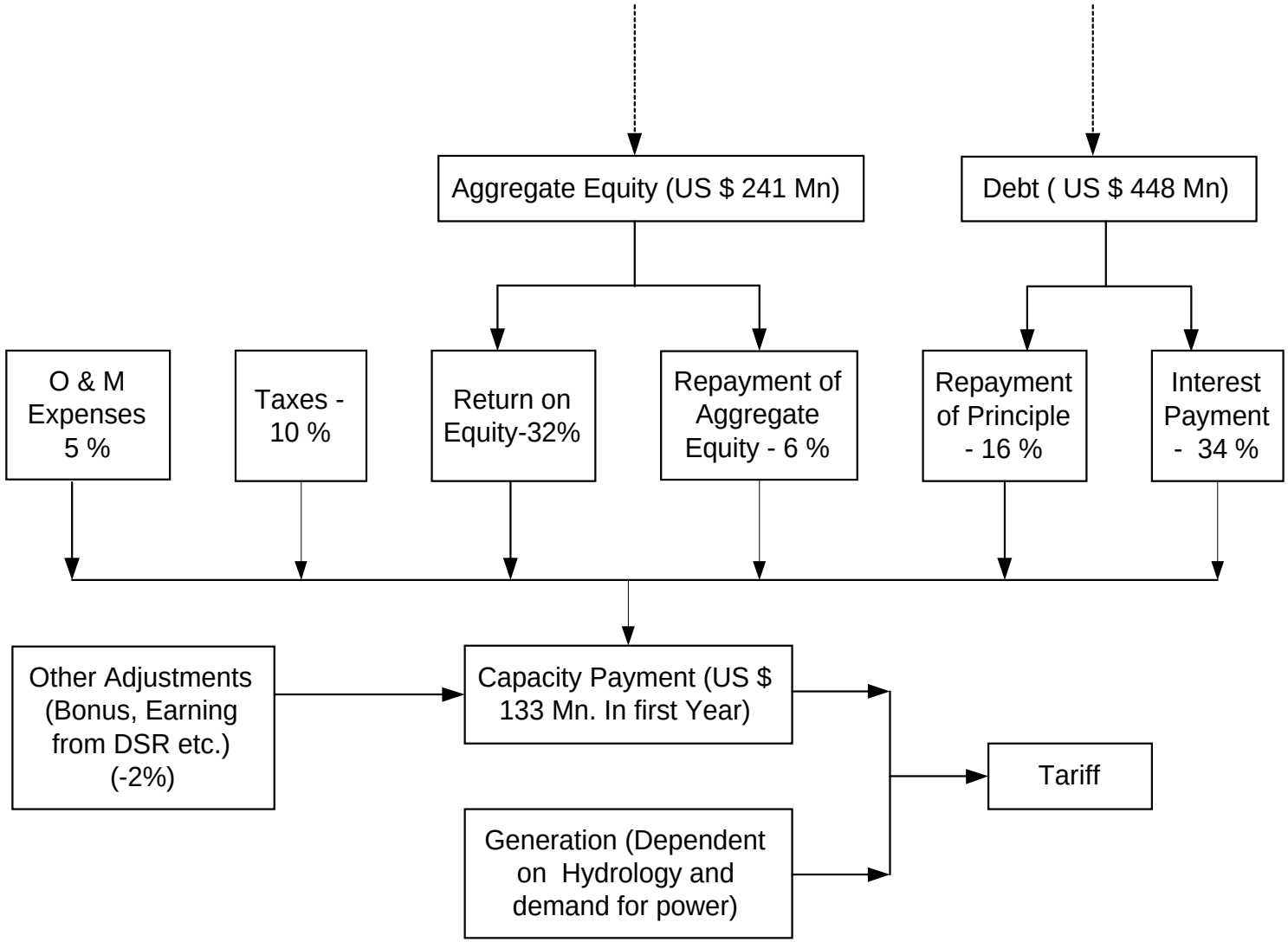


**Figure 4: Capacity Payment structure in the Bujagali PPA**



## 3. Analysis and critique of the PPA

As explained in the earlier section, cost and tariff related aspects are defined in Annex D of the PPA. Prayas Energy Group has developed a mathematical model of this structure to analyze the impacts of various provisions in the PPA. Major assumptions used in the base case analysis are indicated in Annex I. The following section summarizes major conclusions of this analysis.

### 3.1. "Maximum Capacity Payments" and Actual Capacity Payments:

The Capacity Payments will effectively work out to be much higher than the "Maximum Capacity Payment" specified in Table 4 of Annex D in the PPA[5]. In the first year, the Capacity Payment will be about $132 million. In comparison, the PPA – and the World Bank's Project Appraisal Document – claim that Capacity Payments will amount to $97 million in the first year of operation, and will reach a maximum of $111 million. The difference decreases in the subsequent years. Figure 5 compares the Capacity Payment calculated according to the PPA provisions with the Maximum Capacity Payment estimated in the PPA. This substantially higher Capacity Payment in the initial years will cause increased financial difficulties for UEB / GoU during this period. As discussed in section 1.13., the option of deferring Capacity Payments is very expensive in the longer term. Thus the Maximum Capacity Payment is essentially a misnomer and misleading. Figure 6 shows the components of the Capacity Payment (excluding the small income from Debt Service Reserve and Liquidity Facility and its repayment).

**Figure 5: Capacity Payment v/s Maximum Capacity Payment (PPA values)**

[5] The Maximum Capacity Payment is not a fixed series, but can be corrected to account for a possible reduction in tariff, due to a World Bank partial risk guarantee and an increase in the term of debt. It will be increased to account for an increase in Tariff Project Costs due to factors such as a delay in Financial Closure, reduced Interim Energy Payments, and Political Force Measure.

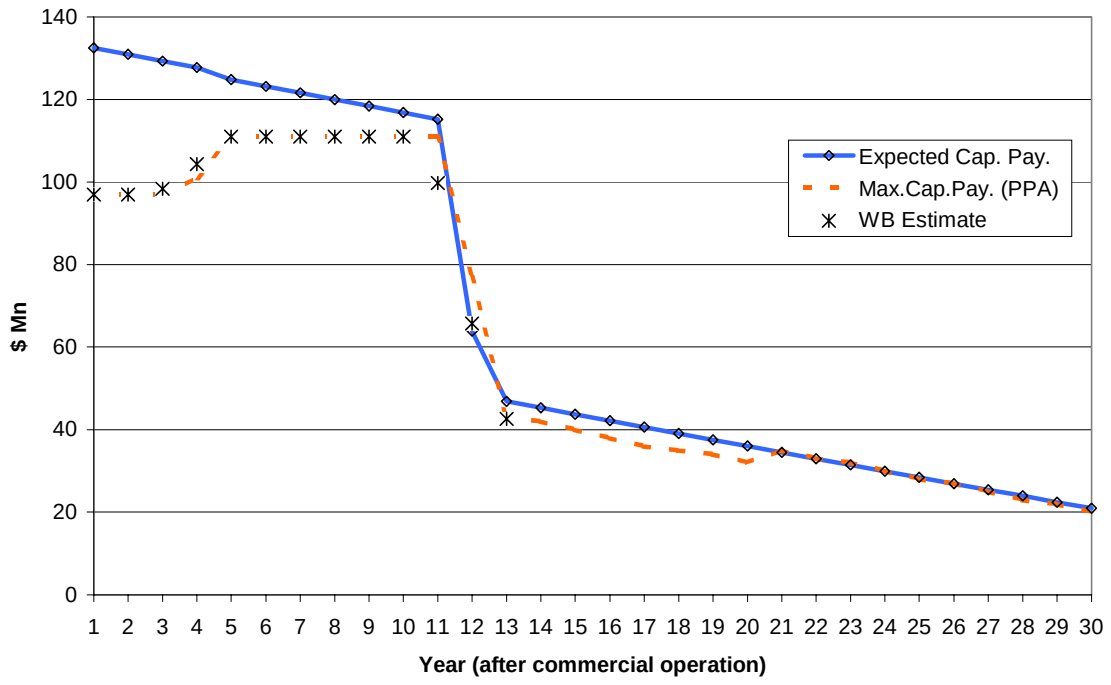
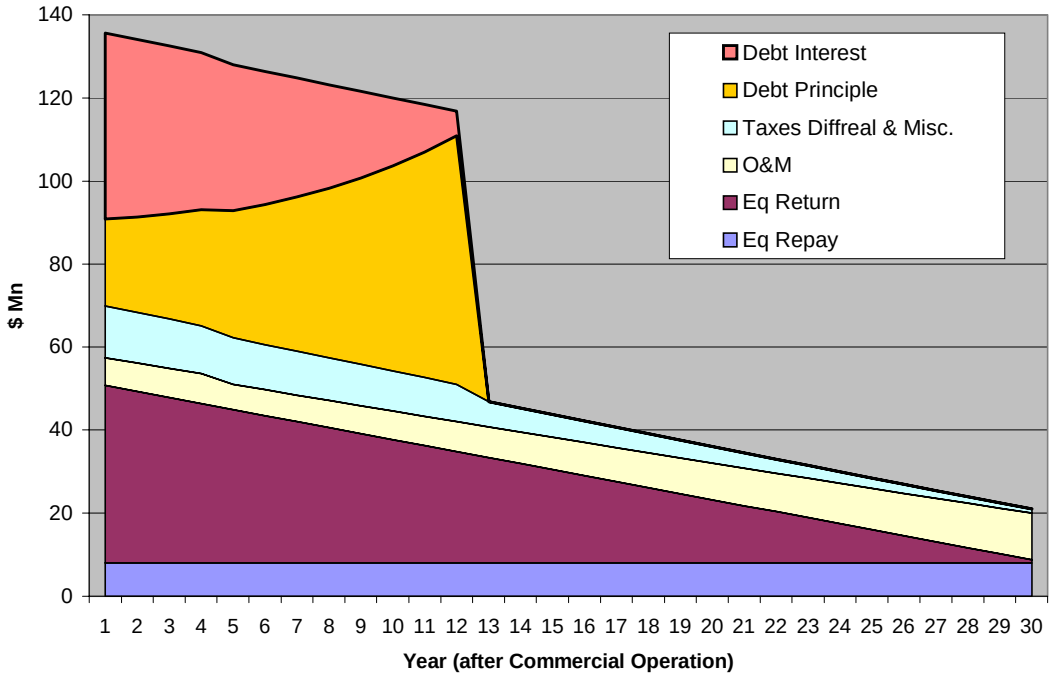



**Figure 6: Components of the Capacity Payment**
(excluding DSR, LF earning and repayment)



3.2. The impact of Assumed Leverage:

If AESNP manages to attain an actual leverage (i.e. a debt:equity ratio) of 80:20, nearly 70% of the saving (compared to a base leverage of 75:25) will accrue as an incentive to AES. As mentioned earlier, the PPA includes no restriction on the extent to which the equity component can be reduced. Unlike the lenders, UEB has no control over this issue. Allowing a reduction in equity to any extent (without a sufficiently large performance bond for the duration of the PPA) is a risky project practice. It reduces the promoter's commitment to the project and increases indebtedness. In fact, AES is rewarded by an increase in the internal rate of return of over 1% for putting in less equity! Allowing a promoter to reduce his equity should in itself be a sufficient incentive for the promoter, as this reduces his risk investment. If the added incentive to AESNP were withdrawn, the average Capacity Payment would decrease by about $1.8 million p.a.

3.3. The impact of Cost Saving:

As mentioned earlier, any saving due to a reduction in actual EPC costs below the estimated EPC cost of $330 million (in 1998) will be shared between AESNP and UEB. The actual EPC contract, according to the World Bank PAD, amounts to $320 million. After accounting for factors such as changes in the spending profile and an increase in estimated EPC cost due to inflation (0.72% p.a.), the reduction in EPC cost works out to be $25.5 million. AESNP is allowed to claim over $15 million of this saving. The PPA provides for this saving to be included in the Capacity Payment calculations, as expenditure funded by AESNP through equity. Moreover, AESNP is also allowed to earn a return of 20% p.a. during the construction period (and capitalize it). This will increase AESNP's equity by $20 million by the time the project starts (for a reduction in the EPC cost of $25 million). In this manner, nearly the entire benefit of the cost reduction accrues to AESNP alone. This is certainly a one-sided provision.

If this provision were equitable, in that half of the benefit of cost reduction was given to UEB, the capacity payment would decrease by about $2.5 million in the first year (and an average of $1.5 million p.a. over the 30 year life of the PPA).

3.4. Taking out $16 million from Interim Energy Payments:

As mentioned earlier, the PPA assumes that AESNP will recover $16 million from the Interim Energy Payments. This is a very strange provision which gives a hidden benefit to AESNP, over and above the benefits explicitly identified in the PPA. As a prudent industry practice, the Interim Energy Payments need to be utilized to reduce the debt and hence the project cost. None of it should be given to the equity holder. If this approach was adopted and the Interim Energy Payments were used to reduce the Tariff Project Cost, the Capacity Payments would decrease by $2.8 million in the first year (with an average reduction of $1.3 million p.a. over the lifetime of the PPA).

Considering the standard industry practice, it is likely that AESNP will be required to bring in substantial equity just before the commercial operation date (to pay for the final installment of the EPC contractor). This equity contribution is likely to be in the range of $15 to 18 million. It is interesting to note that AESNP will earn a similar amount at that time from the Interim Energy Payments.

3.5. High cost of multiple payment security mechanisms:

As mentioned earlier, the project is supported by multiple payment security mechanisms. The first level of payment security consists of a Liquidity Facility of $20 million and a Debt Service Reserve of about $33 million. (These accounts will be created through the Interim Energy Payment and debt and equity financing respectively.) The second layer of security is a requirement which is similar to an escrow facility in that UEB is required to replenish these accounts immediately and, if necessary, by directly depositing electricity export revenues in them. The third level of security is the Guarantee provided by the government of Uganda, and finally IDA's Partial Risk Guarantee. It is not uncommon for investors to seek multiple payment security mechanisms in projects like Bujagali. Yet in the light of an escrow-like arrangement, a Guarantee by the government of Uganda and a Partial Risk Guarantee by IDA, it would have been desirable to eliminate the features of the Liquidity Facility and the Debt Service Reserve. Doing so would have reduced the project cost by about $50 million, i.e. by about 9%. This would have reduced the Capacity Payment by about $9 million in the first year (and by an average of $4.3 million p.a. during the lifetime of the PPA).

Another important issue that merits attention is the very high cost of loans and financing fees of the export credit agencies (ECAs). For example, in this case the ECA Exposure Premium alone amounts to about 20% of the actual ECA support, and so the premium accounts for about 7.5% of the total project cost.

3.6. The impact of high capital costs:

The World Bank claims in its PAD that the EPC cost of the project is extremely competitive. According to the Bank, this cost was checked by three different agencies and benefited from competitive pressure between two different projects in Uganda (i.e. the Bujagali and Kalagala hydropower projects). The advice of the three consultants appointed by the three key parties – the government of Uganda, AES and the lenders – all concluded that the EPC cost of $320 million was reasonable.

This is a highly surprising conclusion considering the evidence shown in Annex II of this paper. The cost of the Bujagali project is substantially higher than the cost of another hydro-electric project with comparable features. In the case of the sample project, the cost of supplying and erecting the electro-mechanical equipment is lower than the contracted cost in case of Bujagali, although the sample project has twice the capacity of Bujagali. The cost of electro-mechanical equipment is $0.59 million / MW in the case of Bujagali, and $0.28 million / MW in the case of the sample project (of a very similar nature).

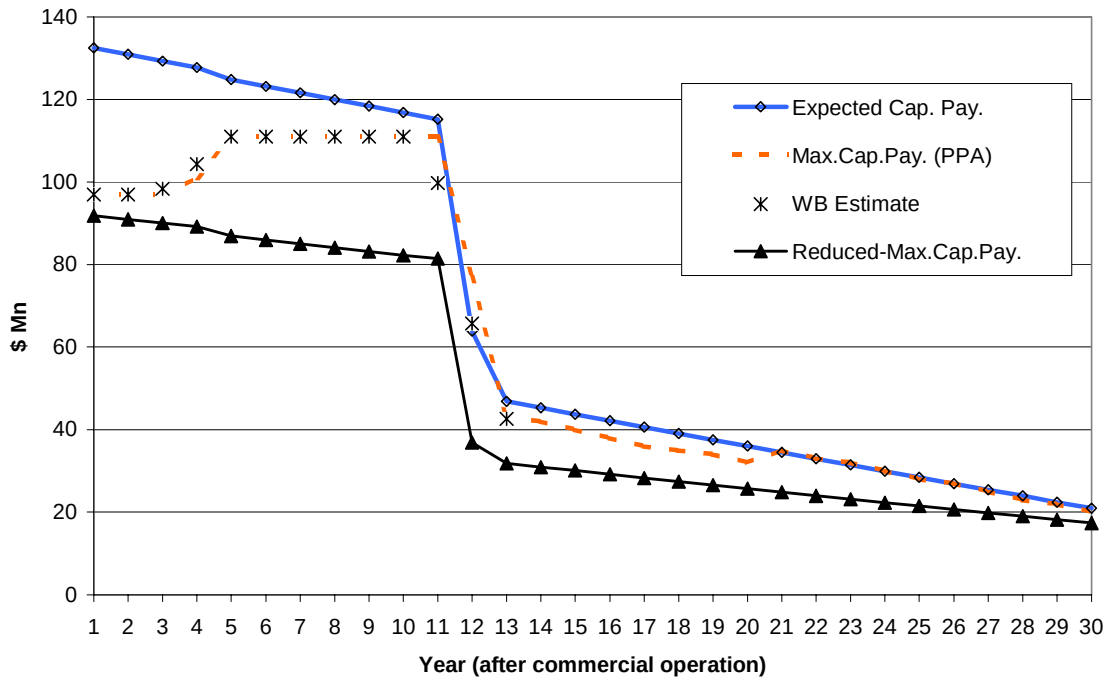
As an indicative exercise, the impact of a limited 20% reduction in the EPC and non-EPC Costs on the Capacity Payments was calculated. Dependent factors like IDC and financing fees were also adjusted to reflect this reduction in cost. The reduction in Capacity Payments worked out to be about $26 million in the first year (and an average of $13 million over the lifetime of the PPA).

3.7. Possible reductions in Capacity Payments due to better negotiations:

Sections 3.2. through 3.6. demonstrate how changes in five critical aspects of the Bujagali project would each impact the Capacity Payments by UEB. The cumulative impact of these factors is lower than a simple addition of the individual reductions. This is because the impacts of some of the factors overlap. If, for example, the capital cost is reduced, the effect of removing the Assumed Leverage Ratio decreases as the equity and debt considered in the Capacity Payment calculations also decrease. It needs to be noted that the five changes considered above do not change the basic framework of the project, i.e. the financing pattern, the ownership and the return on equity. Thus this section articulates the possible gains that Uganda could have obtained mainly by better negotiations and a competitive bidding process.

In a nutshell, even if one assumes that the Bujagali project is a least cost option, the above analysis shows that the Capacity Payment could have been reduced by about $40 million in the first year, and by an average of $20 million over the lifetime of the PPA. This would result in total savings of $600 million over the full term of the PPA, which at a discount rate of 10% equals a Net Present Value of $280 million. Assuming a high generation estimate of 1414 MU p.a., this saving translates into a potential reduction in the power tariffs of US Cents 2.8 /unit for Bujagali during the first year of operation..

**Figure 7: Possible Reduction in the Capacity Payment**




3.8. Inadequate disclosure to and control by UEB and the government:

As a standard project practice, properly negotiated IPP contracts have many provisions to share key contractual and design information with the buyer. Often, the buyer also has a right to approve key contracts (for example on financing, EPC, and O & M). Further, properly negotiated contracts also stipulate that agreed mathematical models of costs and tariff calculations as well as "as build" drawings, designs and manuals be deposited with the buyer. All these provisions are aimed at securing the buyer's interest. Ultimately it is the buyer who pays for all these assets, and is interested in operating the project even after termination of the PPA. The Bujagali PPA provides for depositing "as build" drawings with UEB. However it neither provides for any control or review of financing and other contracts by UEB, nor for the agreed mathematical model of the PPA calculations to be deposited.

Another noteworthy aspect is that the PPA structure and the wording of various provisions are at times ambiguous and prone to different interpretations. This increases the possibility of disputes. At times even the cross-referencing to different provisions in the PPA is incorrect (see for example Annex D S. 5.7 c ii).

3.9 Unjust conditions on the government:

Another disturbing feature of the project contracts is the condition relating to the privatization and restructuring of UEB. The Implementation Agreement specifies that the government must restructure (i.e. privatize) UEB. It is deplorable that IPPs force such policy decisions on developing country governments. It is even more deplorable that the World Bank actively supports and encourages such provisions and projects.

## 4. The role of the World Bank: inadequate analysis and misinterpretation

The World Bank Group is closely involved in financing the Bujagali project and in restructuring Uganda's power sector. The World Bank PAD claims that one of the significant added values of the Bank's involvement in the project is in the form of "structuring of the proposed project to ensure proper risk sharing amongst the parties" (PAD, pg. 19). The analysis presented in the PAD however falls substantially short of this claim and raises serious doubts about the quality and accuracy of the Bank's analysis.[6] Some examples of gaps and inaccuracies in the Bank's presentation are discussed below:

### 4.1. Claims regarding interest cost certainty and EPC liquidated damage payments:

The World Bank (on pg. 19 and 43 of the PAD) claims that the PPA provides for the protection of UEB from an increase in interest rates. The actual provisions in the PPA (dated 8 December 1999) do not support this claim. The PPA does not specify any ceiling on the interest on debt, and in fact provides that actual interest will be charged in the Capacity Payment. The PPA only provides for a certain Maximum Capacity Payment, and allows UEB to defer the excess payments if the actual Capacity Payment is higher than the Maximum Capacity Payment. But as mentioned earlier, any such deferral carries a high interest charge of 13%, which essentially implies a provision of delayed payment charges. Therefore, contrary to the World Bank claims, no ceiling on interest exists.

Another World Bank claim which does not appear to be based on actual provisions in the PPA of 8 December 1999 relates to the payment of liquidated damages in case of delays in construction by the EPC contractor. In the PAD (pg. 43), the World Bank claims that in case of delays, the EPC contractor is liable to pay liquidated damages, and that such damages would flow directly to the government under the provisions of the PPA. Liquidated damages, according to normal industry practice, are applied to Project Cost by reducing debt. This results in a reduction of the debt equity ratio. The actual provisions in the Bujagali PPA are very different from what the World Bank claims. According to S. 8.2. of the PPA, AESNP pays UEB $25,000 for each day of delay beyond 47 months from the start of construction. (This amount is reduced if some of the units are already commissioned.) Yet according to the Bank, the EPC contract requires the contractor to pay AESNP $213,000 for each day of delay in construction beyond 44 months. Thus, during the first three months of construction delays AESNP does not forward any damage payments to UEB, and thereafter forwards less than 12% of the damages it receives from the EPC contractor.

### 4.2. Claims regarding reasonable EPC costs:

[6] Prayas Energy Group asked IFC to clarify the issues raised in this section of the paper ten days before the publication date. IFC did not respond to this request.

The PAD explains in detail why, according to the World Bank, the EPC cost of the Bujagali project is reasonable. It argues that competitive pressure existed during project development and that the cost estimate of the lenders' Independent Engineer was within 1.5% of the Actual EPC contract cost (see PAD pg. 32). Yet it is highly surprising that the entire analysis failed to point out the high cost of the EPC contract, and especially of items such as the electro-mechanical equipment. As shown in Annex II, some hydroelectric projects have managed to acquire electro-mechanical equipment (with an identical scope of work) at less than half the cost claimed in the Bujagali EPC contract. It is difficult to see how such a large difference in the cost of electro-mechanical equipment could be justified. The World Bank, with its large database of power projects around the world, should have been able to clearly identify and point out such excessive costs.

Another weakness in the evaluation of the project cost by the World Bank is the lack of evaluation and comments on the soft costs of the project. Soft costs such as Non-EPC costs, together with financing costs, account for nearly 45% of the total project costs. These costs are known to be a major source of cost inflation and need to be evaluated carefully.

One wonders how the World Bank – a supposed "Knowledge Bank" – missed such major issues, and instead supported increasing the debt burden of a highly indebted country like Uganda. At this rate, it is difficult to expect that the Bank would have reasonably undertaken an analysis of other, quite likely more favorable options such as geothermal power plants in Uganda before arriving at its decision to fund Bujagali.

### 4.3. Other issues:

Apart from the serious issues of inadequate analysis and misrepresentation of facts, the World Bank's PAD also reveals a poor understanding of the PPA provisions on several counts. For example, on pg. 23 it mentions that "[t]he Sponsor will provide lenders with parent corporate support for a debt service reserve in the form of a letter of credit to the extent debt service reserve obligations are not funded out of contingencies built into the project costs from interim energy revenue". Yet according to the PPA, the Debt Service Reserve is part of project cost. It will be funded through debt and equity and not through the Interim Energy Payment. Allowing AESNP to substitute the Debt Service Reserve by a letter of credit would significantly increase the benefits to AESNP, in a way which is again not anticipated in the PPA.

Another such example relates to the assumption regarding Interim Energy revenue. The PAD analysis assumes that the Interim Energy revenue will amount to $23 million. After deducting $20 million for the Liquidity Facility, the PAD directly uses the remaining $3 million to reduce the project cost. In doing so, the Bank ignores two crucial provisions related to the utilization of Interim Energy revenue. According to these provisions, the EPC contractor is entitled to an incentive of up to $3 million (in return for increasing the Interim Energy revenue through early construction). Secondly, AESNP is entitled to taking out $16 million. Any excess revenue from the sale of Interim Energy after

deducting the above amounts would be used for reducing project cost. Thus, if the PAD assumes the Interim Energy revenue to be $23 million, it needs to increase the Tariff Project Cost by $16 million, which it does not seem to have considered.

## 5. Conclusions

The main conclusions of the above analysis can be summarized as follows:

- The "Maximum Capacity Payment" specified in the PPA does not cap the Capacity Payments which UEB must make to AESNP. It only allows payments above the supposed Maximum Capacity Payment to be paid at a latter date, along with an interest of 13% p.a. The actual yearly Capacity Payments will reach a maximum of $132 million. This is substantially higher than the supposed Maximum Capacity Payment, which the PPA and the World Bank's PAD claim to be $111 million.

- It would have been possible for UEB and the government of Uganda to reduce the Capacity Payments to AESNP by about $40 million in the first year, and an average of $20 million p.a. throughout the term of the PPA. This amounts to savings with a Net Present Value of $280 million over the lifetime of the PPA (at a discount rate of 10%). Such savings could have been achieved through better negotiations regarding the unfavorable provisions related to the Interim Energy Payments, Assumed Leverage and Cost Saving, and by ensuring a reasonable capital cost of the project.

- The World Bank analysis of the PPA, as reflected in the PAD, is substantially weak. At times it contradicts the actual provisions of the PPA. It also fails to highlight key issues such as the high capital cost of the project, the risks of possible high debt cost, the risk of very low liquidated damages to UEB in case of construction delays, and the provision of AESNP taking out $16 million from the Interim Energy Payments before the commercial operation starts.

- The PPA is also substantially unfavorable to UEB and the Ugandan government on several other accounts. For example, the PPA requires the government to restructure UEB, limits the control of UEB and the government on the financing and other contracts of the project, and grants AESNP a right of first refusal even after UEB has repaid all the equity, including returns, of the project. Finally, the definition of Financial Closure is very vague. It allows AESNP to declare Financial Closure even if most financing and other project contracts have not been executed yet. This exposes the government of Uganda to significant risk, and is against good industry practice.

## 6. Acknowledgements

We sincerely acknowledge the support provided by Peter Bosshard and International Rivers Network throughout the process of preparing this report. We are also thankful to Mr. Ram C. Sekar for reviewing the draft report and providing valuable suggestions.

## 7. Bibliography

A review of the World Bank Inspection Panel's report on the Bujagali hydropower project, International Rivers Network, June 2002

Implementation Agreement (dated 8 December 1999) between AES Nile Power Limited and the Government of Uganda (GoU)

Pervasive Appraisal Optimism, A review of the World Bank's appraisal of the Bujagali project, by Peter Bosshard, International Rivers Network, May 2002

Power Purchase Agreement (dated 8 December 1999) between AES Nile Power Limited and the Uganda Electricity Board (UEB)

Private Gain – Public Risk? The International Experience with Power Purchase Agreements of Private Power Projects, Peter Bosshard, International Rivers Network, 20 November 2002

The World Bank Project Appraisal Document, Report No. 22963 – UG

The World Bank Inspection Panel's report and findings on the Uganda Third Power Project, the Power IV Project and the Bujagali Hydropower Project

- - X- -

## 8. Annex I: Assumptions for the base case

The mathematical model and analysis in section 3 of this paper are based on the following basic assumptions. Other assumptions and changes are mentioned in the respective sections.

**Project cost and financing:**

- Financial Closure in December 2002. The Non-EPC costs and estimated EPC costs are increased to account for this change.
- Construction period 44 months.
- Actual EPC cost $320 million, with the same disbursement schedule as the estimated EPC cost except for the last installment (which is assumed at the time of commercial operation, in line with standard industry practice).
- Financing Fees and Pass Through Costs assumed according to the World Bank's estimate (PAD, $84.7 million).
- Interest During Construction calculated assuming that loans with a weighted average interest of 10% will be available.
- The term of loans is assumed to be 12 years (with repayment starting immediately after commercial operation).
- The (actual) Debt:Equity ratio at the time of Financial Closure is in the range of 20:80, as expected in the World Bank PAD.
- Net Interim Energy Payments will be $16 million (after deducing from the Interim Energy Payments $20 million for the liquidity facility, and $3 million as an incentive for the EPC contractor).
- US CPI (inflation) is estimated at 2.5% p.a.
- The income on the Debt Service Reserve and the Liquidity Facility is assumed to be 6% p.a., and the principle amounts are assumed to be repaid after the loan is repaid.

**Taxation:**

- Withholding Tax of 15% will be applicable on Return on Equity.
- Withholding Tax of 4% will be applicable on all payments made by UEB to AESNP. No additional corporate tax will be payable.
- Withholding tax on repatriation of AEUDC and Cost Savings is ignored.
- No VAT will be payable on the UEB payments to AESNP.

- - X - -

## 9. Annex II: The high capital cost of the Bujagali project

In any power project, the capital cost is one of the most critical aspects that determine the tariff and hence the economic viability of the project. In case of projects developed through the IPP route, the Engineering, Procurement and Commissioning (EPC) cost constitutes the largest component of the capital cost. Apart from the terms of financing, other capital cost components such as financing costs, interest during construction etc. are largely dependent on the EPC cost. Because of this, a proper evaluation of EPC costs is extremely important. In case of the Bujagali project, the estimated EPC cost was $330 million, and due to (limited) competitive bidding and subsequent negotiations, it was reduced to $320 million.

According to the Project Appraisal Document (PAD) of the World Bank, the total capital cost of the project (including financing, IDC and other costs) is estimated to be $582 million. The Bank PAD also concludes that the EPC cost of $320 million for this project is reasonable. This conclusion is mainly based on two factors. First, the Bank presumes that there was sufficient competitive pressure during the process of awarding the EPC contract. Secondly, an independent evaluation of the scope of the EPC contract (by the World Bank) produced an EPC cost estimate which closely matched the actual EPC cost of US$320 million. Table 1 shows the break-up of the EPC cost as shown in the PAD.

**Table 1: Break-up of Bujagali EPC costs**

| No. | Component | Cost ($ million) |
|---|---|---|
| 1 | EPC Engineering | 14 |
| 2 | Civil Works | 147.6 |
| 3 | Electro-mechanical (supply and installation) | 118.3 |
| 4 | Transmission line (supply and installation) | 12.1 |
| 5 | Transportation | 10.4 |
| 6 | Escalation | 9.0 |
| 7 | Contingency | 9.7 |
| | **TOTAL** | 321.1 |

For civil society organizations evaluating the capital cost of any power project is a difficult task. This is because the capital cost data is not available easily, and secondly, the available data is often insufficient to normalize differences such as scope of the contract, taxes etc. The problem is particularly relevant for hydroelectric projects, as the cost of the dam and other civil work can differ significantly from site to site.

Nonetheless it is possible to broadly analyze whether or not the capital cost of a hydroelectric project is reasonable if another somewhat similar project can be identified.

The two projects should be comparable in terms of major features such as dam height, installed capacity, type of turbines and break-up of the capital cost components. Incidentally, one hydroelectric project being developed in central India, the Sri Maheshwar Hydroelectric Power project (SMHEP), is broadly similar to the Bujagali project. Substantial details about various cost components of this project are available. Similar to the Bujagali project, the SMHEP project is also being developed through the IPP mode. It involves the construction of a dam (roughly of the same type and size as the Bujagali dam, i.e. a rockfill / concrete dam with a height of about 35 meters). SMHEP uses a similar type of turbines, and has a similar head (of about 20 meters). The SMHEP project is also under development since the mid-1990s, but is yet to achieve financial closure, and is expected to start commercial operations around 2006/7[7]. The two projects differ markedly in terms of their installed capacity: The SMHEP project has an installed capacity of 400 MW, compared with 200 MW at the Bujagali project.

The Central Electricity Authority (CEA), an apex statutory body in India responsible for the evaluation and approval of the capital cost of power projects, cleared the SMHEP project in 1996, at a capital cost of about $400 million at the current (year 2002) exchange rate. In 2000, the project promoters approached the CEA again for an upward revision of the cost to around $450 million, due to a delay in project development. But for more than two years, the CEA has not approved the revised cost estimates of the promoters. In comparison, the total capital cost of the Bujagali project is $580 million. SMHEP costs also include components such as financing fees and interest during construction. Unlike in the case of Bujagali, the contract for the supply and erection of electro-mechanical equipment (i.e. turbines, generators, switchyard, transformers etc.) was awarded through an international competitive bidding process. Table 2 shows the break-up of cost components for this contract as quoted by three reputed equipment suppliers.

**Table 2: Electro-mechanical equipment and supply cost for the SMHEP Project**
(All values in $ million, conversion at 48 Indian Rs = $1)

| Cost Component | A | B | C |
|---|---|---|---|
| EoT Cranes | 1.2 | 1.2 | 1.3 |
| T.G Sets | 65.2 | 58.8 | 46.5 |
| Bus duct | 6.1 | 1.6 | 3.8 |
| Power Transformers | 5.3 | 4.7 | 4.0 |
| Control protection | 1.3 | 7.4 | 3.0 |
| Switchgear | 3.9 | 4.9 | 6.0 |
| 11KV & 433 V Switchgear / cables | 4.9 | 3.2 | 1.7 |
| DC Eq. | 0.2 | 0.4 | 0.2 |
| Air con./fans Metering etc | 2.3 | 3.9 | 2.8 |
| Other Costs (duties, erection etc.) | 0.0 | 13.8 | 31.3 |
| **TOTAL** | **90.6** | **99.6** | **100.5** |

[7] The financial closure of the project is being delayed due to several reasons, including strong opposition to the project on environmental and social grounds, high cost of power and economic non-viability.

After negotiations and changes in suppliers, the cost of the contract for the supply and erection of the electro-mechanical equipment was finalized at around $110 million[8]. In comparison, the cost of the supply and erection of electro-mechanical equipment for the Bujagali project, which is half the size of the SMHEP project, is $118 million (excluding the transmission line component). Table 3 depicts the comparative status of the two projects[9].

**Table 3: Comparison of Bujagali and SMHEP Projects**

| No. | Parameter | Bujagali | SMHEP |
|---|---|---|---|
| 1 | Location | Uganda | India |
| 2 | Type of plant | Hydroelectric | Hydroelectric |
| 3 | Type of project | IPP | IPP |
| 4 | Scope | Dam, power house, equipment & transmission line (~100 km) | Dam, power house, equipment |
| 5 | Head | 19 – 21.5 m | 19.3 – 22.2 m |
| 4 | Expected commissioning | 2006/7 | 2006/7 |
| 5 | Installed capacity | **200 MW** (50 MW x 4 units) | **400 MW** (40 MW X 10 units) |
| 6 | Cost of supply & erection of electro-mechanical equipment (excluding transmission line) | $118 million | $110 million |
| 7 | Capital cost (including financing fees and IDC) | $582 million ($700 million, including AEUDC) | $450 million |

Important Note: As shown in the above analysis, the capital cost of the Bujagali project is substantially higher than in the case of SMHEP. In spite of this, even the SMHEP project is economically unviable and socially undesirable. Maximum power generation from the project would occur during the monsoon period when the demand for power is low. During the non-monsoon period, the project generates power for only a few hours a day. (SMHEP has an average yearly Plant Load Factor of about 25 -30%, and a PLF during the eight non-monsoon months of about 8% to 10%.) Several export credit agencies and other financial institutions (for example from Germany and Portugal) have refused funding for

[8] This is somewhat higher than the competitive bidding quotes due to delay and exchange rate variation.

[9] Though this section compares the Bujagali cost with only one sample project, other examples may not be difficult to find. See for example the following announcement: "Bharat Heavy Electricals Limited has bagged a Rs 740 million order from the North Eastern Power Corporation for the supply of hydroelectric generating equipment to the 2 X 30 MW Tuirial hydro project in Mizoram. The power project has been funded by JBIC and is expected to be complete by 2006. The scope of work for the project envisages the design, manufacture, supply, erection and commissioning of two vertical hydro turbines of 30 MW each with matching generators." (Power Line News – 19th October 2002). In this case, the cost of electro-mechanical equipment works out to be $0.26 million / MW.

the project. A Task Force appointed by the government of Madhya Pradesh has also concluded that the cost-benefit ratio for the project needs to be reassessed considering several social and economic factors.

**Conclusion:** The above indicative comparison clearly demonstrates that the capital cost of Bujagali is substantially higher than of a comparable project. The large difference in the capital cost ($2.9 million / MW for Bujagali v/s $1.2 million / MW for SMHEP) cannot be explained even when factors such as the high cost of financing, transport, the different nature of civil works, a transmission line of 100 km etc. are accounted for. Another striking and concrete example of the high cost of Bujagali is the large difference in the cost of similar electromechanical equipment ($0.59 million / MW for Bujagali v/s $0.28 million / MW for SMHEP).

**- - X - -**