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Abstract

For most electric utilities in developing countries the choice of generation technology, the type of financing that is available, the type of ownership of the facility, and electricity tariff policies are not independent variables. This paper reports on an integrated financial, economic and stakeholder analysis of a prospective investment in the Bui hydroelectric generation dam in Ghana. The appraisal of the Bui dam serves as the vehicle to illustrate how the choice of technology, choice of public utility versus independent power producer and available financing packages are linked and what may be their implications for domestic electricity pricing policy. In this case, the Bui dam is both financially and economically better than the alternatives compared here, even if favorable financing terms are not available to this project. At the same time, the risks of cost overruns, water availability and construction delays are risks that are likely to be more prevalent with the development of a hydro dam than in the case of the thermal alternative.

JEL Codes: D61, H43, L94

Keywords: Ghana, electricity, tariff regulation, system planning, investment, privatization.

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An Analysis of Electricity Generation and Tariff Options in Ghana[1]

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1. Introduction

The 285MW Bui hydro-electric power plant, if implemented, would represent a major expansion of the electricity generation capacity in Ghana. This project is set in the context of the expansion plan for the electricity sector in order to meet the growing domestic demand for electricity. In this paper we carry out an integrated financial, economic and stakeholder analysis of the plant where the important variables for the project's success or failure are identified. The characteristics of hydro generation as compared to the alternative thermal option are carefully evaluated in order to ensure that the expansion strategy for generation is the one that is both financially feasible and economically most beneficial to the country.

The integrated analysis of the Bui plant is carried out in the context of the possible reforms in the institutional framework of the industry. The electricity sector in Ghana is characterized by a centralized structure. The Volta River Authority (VRA) is a state-owned vertically integrated utility in charge of the generation and transmission segments of electricity production. By statute, VRA is committed to supply the demand for power in Ghana. In this study we consider a possible change in the institutional framework that is being implemented elsewhere, that is to introduce a degree of competition in the generation segment of the electricity sector, while maintaining the vertical integration of the main generation/transmission components of the utility. Under this scheme, independent power producers would sell power to the vertically integrated utility under long-term contracts. This study considers a reform along this direction as one option. The integrated analysis of the Bui plant is, therefore, carried out under the alternative scenarios where either VRA or an IPP may undertake the project.

[1] This analysis is developed using 1997 data for Ghana. The policy issues analyzed do not necessarily reflect either those of concern to the government of Ghana or the Volta River Authority. The issues studied were chosen solely by the authors of this paper. However, due to the very interesting and complex electricity pricing and investment options available we have chosen the economic context of Ghana to illustrate this analytical model for electric utility decision making.

This would provide policy-makers with information regarding the most appropriate power purchase and financing agreement for the new project.

Due to the historical low cost of electricity generation by hydro plants, the current tariff rates in Ghana are very low. Under the current tariff structure it is unlikely that any of the much-needed new power projects would be financially viable. Because of the necessity to expand its generation capacity, VRA needs to have an improvement in its tariff structure. A number of simulations have been conducted in this study to indicate how the tariff structure could be altered in order that VRA's overall sales revenues would enable the utility to pay for the project. This model could be used with current information to assist in the process of redesigning the structure of electricity tariffs.

2. Overview of the Generation Segment in Ghana

VRA currently operates all the generation facilities in the country. These include the 912 MW Akosombo and 160 MW Kpong hydro-electric power plants, and the 30 MW Tema diesel plant. Akosombo and Kpong plants, commissioned in 1965 and 1984, are located downstream of the Volta Lake. Both plants generate most of the energy currently required on the system. Their long-term average energy generation capability is evaluated at 5866 GWh in total, on the basis of the hydrological period 1936-1993. The Tema diesel power plant was commissioned in 1970. It is expected to participate only marginally in the generation system after year 2000, or may be retired by then due to its high maintenance costs.

The Authority's generating system can no longer meet the growing energy needs of the country. Since 1991, the electricity demand on the system has become higher than the long-term annual average generation of Akosombo, Kpong and Tema (6,107 Gwh consumed in 1991, compared to approximately 6000 Gwh average generation capability). Short-term measures to meet the supply shortfall included the reduction of 1740 Gwh in the contractual supply to the main electricity consumer (Volta Aluminium Company) over the period 1994 - 1996, as well as a significant decrease in exports to neighboring countries. Since 1994 the Authority has been importing power from La Cote d'Ivoire.

The Medium-term plan to meet the electricity requirements of the country is devised in the Investment Programme for the period 1997 - 2007. The Investment Programme makes provisions for increasing the capacity of the system by means of additional thermal and hydroelectric power generation.

The first generation project scheduled for implementation is the 300 MW combined cycle plant at Takoradi. This plant, currently under construction, includes two 100 MW combustion turbines and a 100 MW heat recovery steam generator which uses the exhaust gas from the combustion turbines. The total cost of the project is estimated at about US$ 350 million. With regard to hydro-electric generation, Bui has long been identified among the most significant potential sites in the country and in West Sub-Saharan Africa[2]. The topographical features of the Bui site make it suitable for the development of a large scale hydroelectric plant, with an installed capacity of 285 MW and a generation capability of 1150 Gwh/year.

3. Electricity Demand Forecast

In 1994 VRA developed a demand forecast[3] for the period 1994 - 2015. Table 1 shows the data for the period 1997 - 2007, which has been used as the basis for this study. The demand forecast has been produced by VRA on the basis of the following assumptions:

1) Domestic load : is projected to increase until 1998 at an annual rate of 5.5%, and then at 4.0% until 2003. A constant 3% annual rate of increase is assumed to occur after year 2004.

2) Volta Aluminium Company (VALCO) : is the main consumer in the system with about 2,800 GWh/year (about 45 percent of the total demand). The authority already negotiated in 1994 a reduction of 1740 GWh in the contractual supply to VALCO over

[2] Coyne et Bellier, Bui Hydroelectric Project Engineering Study, 1995. A second hydro power site in Ghana is Hemang. Hemang is suitable for the development of a medium scale plant with a generation capability of 330 Gwh/year. Hemang's size indicates that it cannot be considered an alternative to Bui.

the period 1994 - 1996. VRA expects to supply 2760 GWh/year to VALCO for the period 1997 - 2007.

3) Exports : exports of power to Togo and Burkina Faso are projected to be a marginal part of the total system generation. VRA expects to export 110 GWh/year in the period 1997 -2007.

4) Losses : losses in the transmission grid are taken to be 3% (at the same level as in the past five years).

Table 1
Electricity Demand Forecast : 1997 - 2007

	1997	***1998***	***1999***	***2000***	***2001***	***2002***	***2003***	***2004***	***2005***	***2006***	***2007***
Domestic Load											
- Energy (GWh)	4154	4382	4539	4702	4871	5054	5288	5445	5608	5778	5949
% Change		5%	4%	4%	4%	4%	4%	3%	3%	3%	
- Capacity Demand (MW)	697	739	767	797	828	862	906	936	964	993	1023
Export											
- Energy (GWh)	110	110	110	110	110	110	110	110	110	110	110
- Capacity Demand (MW)	19	19	19	19	19	19	19	19	19	19	19
Valco											
- Energy (GWh)	2760	2760	2760	2760	2760	2760	2760	2760	2760	2760	2760
- Capacity Demand (MW)	320	320	320	320	320	320	320	320	320	320	320
Total System Demand											
- Energy (GWh)	7024	7252	7409	7572	7741	7924	8156	8315	8478	8646	8819
- Capacity Demand (MW)	1036	1078	1106	1136	1167	1201	1245	1275	1303	1332	1362
Tot. Generation Required (1)											
- Energy (GWh)	7235	7470	7631	7799	7973	8162	8401	8564	8732	8905	9084
- Capacity (MW)	1067	1110	1139	1170	1202	1237	1282	1313	1342	1372	1403

(1) Average losses: 3.0%.
Source: VRA, Bui Hydroelectric Project Feasibility Study, 1996.

[3] The demand is measured as the power and energy generation required from the plants (i.e. including the losses in the transmission grid).

4. Development Plan of the Generation Segment of the Industry

The 300 MW combined cycle plant in Takoradi is expected to start operations by the end of 1997, increasing the long-term average generation capability of the system to approximately 7,500 GWh/year. In order to meet the projected electricity requirements, an additional 200 MW thermal generation capacity is planned to be installed by 1999[4]. After the commissioning of this additional capacity[5], two alternative strategies "with and without Bui" are envisaged by VRA.

Tables 2 and 3 show the development plan for the period 1997 - 2007 in the two scenarios. With the implementation of the 285 MW Bui plant, the generation capacity of the system is raised to 1600 MW. No additional generation units would, therefore, be required before 2007. On the other hand, in the "Without Bui" scenario VRA envisages to undertake two 100 MW thermal units in 2002 (a 100 MW heat recovery steam generator associated with the two gas turbines implemented in 1999, and an additional 100 MW combustion turbine) and an additional 100 MW thermal plant in 2006.

Table 2
Development Plan 1997 - 2007 (Without Bui Scenario)

Year	Units	Added Capacity (MW)	System Demand (MW)	Thermal Power (MW)	Hydro Power (MW)	Total Power (MW)
1997	GT1,GT2,CC1-2	300	1067	300	815	1115
1998			1110	300	815	1115
1999	GT3, GT4	200	1139	500	815	1315
2000			1170	500	815	1315
2001			1202	500	815	1315
2002	CC3-4, GT5	200	1237	700	815	1515
2003			1282	700	815	1515
2004			1313	700	815	1515
2005			1342	700	815	1515
2006	GT6	100	1372	900	815	1615
2007			1403	900	815	1615

[4] On the basis of the VRA projections, the total energy demand on the system would again exceed the generation capacity starting from 1999.
[5] This thermal capacity should be provided by two 100 MW combustion turbines. VRA, Bui Feasibility Study, cit.

Table 3
Development Plan 1997 - 2007 (With Bui Scenario)

Year	Units	Added Capacity (MW)	System Demand (MW)	Thermal Power (MW)	Hydro Power (MW)	Total Power (MW)
1997	GT1,GT2,CC1-2	300	1067	300	815	1115
1998			1110	300	815	1115
1999	GT3, GT4	200	1139	500	815	1315
2000			1170	500	815	1315
2001			1202	500	815	1315
2002	BUI	285	1237	500	1100	1600
2003			1282	500	1100	1600
2004			1313	500	1100	1600
2005			1342	500	1100	1600
2006			1372	500	1100	1600
2007			1403	500	1100	1600

Source: VRA, Bui Feasibility Study, cit.
Note: GT and CC stand for gas turbine and combined cycle plants.

5. The Bui Project

A. Project Description

The Bui site is located on the Black Volta, approximately 150 kilometers upstream from Volta Lake, at the border between the Northern and the Brong-Ahafo Regions. The main dam will be located in the deep gorge created by the Black Volta in the Banda Hills. It will have a maximum height above the foundation of about 110 meters, and a crest length of 470 meters. The dam body will be made of roller compacted concrete. Two saddle dams of a maximum height of 37 meters will also be constructed at a distance of about 1 km from the main dam. Three turbine units are planned to be installed. The estimated generation capacity is 285 MW with an annual energy generation of 1150 GWh. As physical infrastructure in the region is poor, the project must also provide for the construction of appropriate facilities.

The length of the reservoir along the Black Volta and its tributaries will reach 40 km with a surface of 440 square km. Its capacity is estimated at 12,600 million cubic meters, with an active storage of approximately 6,000 million cubic meters. The reservoir lies in part within the boundaries of a natural reserve, the Bui National Park, established in 1971. The Park constitutes a rich wildlife reservoir and belongs to the category of “Wildlands of special concern". In addition, about 30 villages, inhabited by 30,000 people involved mainly in agriculture activities, are located in the reservoir area. In order to mitigate its environmental impact, the project proposes detailed resettlement programmes and a plan for the protection of an area equivalent to the part of the Park flooded[6].

The construction period of the Bui project is estimated to be five years. If construction were to begin in 1997, the plant would start operations in year 2002. The project has six components:

1) *Preparatory Works and Construction Facilities*:
include the cost of infrastructure (road between Bamboi and Bui site and bridge across the Black Volta downstream of the dam) and project site facilities.

2) *Civil Works*:
include the cost of river diversion, main dam, saddle dams and powerhouse station.

3) *Hydro-electromechanical Equipment*:
include the hydro-electric equipment of the power plant (turbines, generators and transformers), and the equipment of the intakes and the spillway.

4) *Interconnection with the Transmission Grid*:
include the necessary lines and entries in the existing substation as well as the cost of the "New Kumasi" 161 kv substation for transmission of the power generated to Kumasi.

5) *Engineering and Administration Costs*:
include the detailed design studies, construction drawings, and construction supervision.

6) *Environmental Impact Mitigation Costs*:
include reforestation, resettlement, extension of the Bui National Park and improvement of the Bui National Park management.

B. Project Cost and Financing

The total cost of the project is estimated at US$ 310 million in 1997 prices, with a foreign exchange component of US$ 244 million (about 79% of the total). The cost in

[6] A variety of socio-economic impacts, both positive and negative can be anticipated as a result of the creation of a large reservoir along the Black Volta. Negative impacts include the inundation of existing settlements and roads, the loss of agricultural land and tree crops, the disruption of community structures, and the hazard of increased incidence of certain water-related diseases. On the positive side, the resettlement plan should provide a higher standard of living and improved community infrastructure. The project should also be an opportunity for the Bui National Park to become efficiently maintained and controlled. VRA, Bui Feasibility Study, cit.

domestic currency is projected to be 104 billion Cedis[7] (approximately 65 million US$). The cost estimates are based on the experience of contracts of similar characteristics recently awarded in the region after international bidding. The project cost is taken in this analysis to be the same regardless of the entity undertaking the plant (VRA or an independent power producer). The investments in the various components of the project are shown in Table 4.

This study assumes two different financing structures for the project depending on whether VRA or an IPP undertakes the project. The components of the proposed financing structure of the project in both scenarios are shown in Tables 5 and 6.

Project financing if VRA undertakes the project

The project financing structure assumed in this analysis is based on the recent experience of VRA with the Takoradi combined cycle plant. The authority would provide the funding for the domestic-currency component of the project cost as equity, and would raise internationally the finances to meet the foreign-exchange requirements. In this regard, VRA expects to be able to obtain loans at a concessionary rate from multilateral development institutions. Export credits and non-subsidized financing would cover the balance of the foreign-currency requirements.

Project financing if an IPP undertakes the project

It is assumed that the project sponsors would finance the domestic component of the project cost. Export credits and non-subsidized financing would provide the foreign-currency requirements.

[7] The Cedi is the Ghanaian currency unit. The exchange rate in 1997 is about 1,600 Cedis/US$.

Table 4:
Bui Project Cost
(1997 Price Level)

Item	**Foreign Exchange (in ml. US$)**	**Domestic Currency (in ml. Cedis)**
Preparatory Works and Construction Facilities	23	11,968
Civil Works	105	49,013
Hydro-electromechanical Equipment	61	8,100
Interconnection with Transmission Grid	26	8,410
Engineering & Administration Costs	28	12,300
Environmental Impact Mitigation Costs		12,000
TOTAL INVESTMENT COST	**244**	**104,161 (about 65 ml. US$)**

Source: Coyne et Bellier, Bui Engineering Study, cit.

Table 5
Project Financing (if VRA Undertakes the Project)
(1997 Price Level)

Institution	**Maturity (years)**	**Nominal Interest Rate**	**% of debt Financing**	**Equity (in ml. Cedis)**
Loan from Development Institution A (in US$)	20	6%	58%	
Loan from Development Institution B (in US$)	20	3%	15%	
Export Credits & Non-subsidized Financing (in US$)	15	8.5%	27%	
Volta River Authority				104,161

Source: VRA, Bui Feasibility Study, cit.

Table 6
Project Financing (if an IPP Undertakes the Project)
(1997 Price Level)

Institution	**Maturity (years)**	**Nominal Interest Rate**	**% of debt Financing**	**Equity (in ml. Cedis)**
Export Credits & Non-subsidized Financing (in US$)	15	8.5%	100%	
Project Sponsors				104,161

6. Financial Analysis

A. Assumptions

As mentioned above, the financial analysis of the Bui plant is carried out under the alternative scenarios where either the VRA or an IPP sponsors the project. The model for each scenario is developed on the basis of the following assumptions:

<u>VRA undertakes the project</u>

1) *Exports and VALCO* - Because of the steady increase in domestic demand for power, the project's exports to Togo and Burkina Faso are taken to remain constant in the following years. The main foreign customers include the Communaute Electrique du Benin (CEB) of Togo and SONABEL of Burkina Faso. In addition, VRA is billing electricity sales in US$ to VALCO, the main domestic consumer in the system. It is assumed that the project's exports to Togo and Burkina Faso, and the power sold to VALCO will be equal to 5% and 15% of total sales, respectively.

2) *Domestic Sales* - The main domestic consumers include: (1) the Electricity Corporation of Ghana (ECG), a state owned enterprise which buys electricity in bulk for distribution in Southern Ghana; and (2) the Northern Electric Department (NED), a department of VRA in charge of the distribution of electric power in Northern Ghana. ECG and NED are projected to demand 65% and 10% of the energy generated sold domestically. The fast growing domestic mining and manufacturing industries will demand the balance of the energy generated.

3) *Running Costs* – The running costs of hydro plants are the operating and maintenance costs. These costs vary from one plant to another, depending upon the degree of automation of the plant, its age, and its size. The annual operating and maintenance costs of Bui at the 1997 price level are taken to be equal to 0.5% of the total construction cost in 1997 prices. This assumption is consistent with standard estimates. Running costs, excluding labor, are expected to remain constant in real terms throughout the life of the project. It is assumed that wages will rise in real terms by 2 percent a year as income grows in the country. The domestic and foreign component of

running costs are adjusted annually to reflect domestic and foreign inflation. VRA does not plan to employ additional staff for the operation of the project.

4) *Interest during Construction* - Capital costs exclude interest during construction.

5) *Income Tax* - As a state-owned enterprise, VRA is exempt from paying corporate income tax.

6) *Accounts Receivable and Working Capital* - The generation facilities currently operated by VRA have a collection period equal to approximately 45 days. On the basis of the VRA's average collection performance, it is assumed that 16.7 percent[8] of Bui's annual billings is collected the following year. Accounts payable are also taken to be equal to 45 days of operating expenses. The desired stock of cash balances to be held as working capital is projected to be 2% of sales revenues.

7) *Project Life* - The operating life of the Bui project is estimated at 45 years. The hydro-electromechanical equipment of the plant will be replaced after 25 years of operations. Bui's civil works are expected to have a real salvage value at the end of the project life equal to 25% of the original cost[9].

<u>If an IPP undertakes the project</u>

1) *Sales* - The IPP will sell all the power generated by the plant to VRA at a flat tariff specified in the power purchase agreement. The flat tariff is set in order to achieve a pre-specified real return on equity.

2) *Running Costs* - as for VRA

3) *Interest during construction* - as for VRA

4) *Income Tax* - The IPP will pay an income tax equal to 46% of taxable income.

5) *Working Capital* - It is assumed that 16.7 percent of the IPP's annual billings to VRA is collected the following year. Accounts payable and desired stock of cash balances are taken to be as for VRA.

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[8] This is equal to 45 days divided by 365.
[9] This corresponds to an annual rate of economic depreciation approximately equal to 1.7 percent.

6) *Real Return on Equity* - It is taken a real rate of 15%, which is higher than the one required by VRA.

7) *Debt Financing* - As mentioned above, it is assumed that the IPP, differently from VRA, will not be able to obtain financing at a concessionary rate, but will have to pay a nominal rate of 8.5% on US$ denominated debt.

B. Perspectives of Analysis and Different Profiles of Financial Benefits and Costs

Different profiles of financial costs and benefits for the project can be identified depending on the following aspects: the entity undertaking the financial analysis (VRA or an IPP), the availability of thermal generation as an alternative to the hydro facility, the sponsorship of the plant (VRA or an IPP), and the perspective used in the analysis (utility vs. project).

Utility and project points of view

The utility standpoint looks at the project as part of the parent company's whole operations, evaluating the changes in the utility's cash flows that occur as a consequence of the project. If the hydro power plant is not implemented, a combination of thermal plants would be required to generate the quantity of electricity with the corresponding load factor of the Bui facility. This implies that, when a utility is evaluating a hydro-electric project, the cost savings gained by not having to implement the set of thermal alternatives are the benefits attributable to the hydro alternative.

In contrast, the analysis of a power plant from the project perspective aims at assessing the financial viability and sustainability of the plant, by considering only the actual cash flows created as a consequence of the project. A utility should develop the financial analysis of a power project from this perspective in order to know if the plant is able to generate enough cash to repay its loans. If enough revenues are not forthcoming, an adjustment may be required to the whole structure of the utility's tariff in order to yield sufficient cash to cover the financial costs of the project. IPPs will obviously develop the financial analysis only from the project perspective[10]. In this case, the project revenues reflect the terms of the power purchase agreement[11].

Financial benefits and costs when VRA undertakes the project itself

The different profiles of financial costs and benefits for both the utility and the project points of view are outlined below.

Financial Benefits

From the utility point of view, the financial benefits to be considered in the analysis (when thermal generation is certain to be the alternative to a hydro plant) include: 1) the avoided costs to the parent company of replacing the power supplied by the hydro plant with thermal power; and 2) the incremental sales revenues at the current tariff structure occurring at the utility level as a consequence of the project (if the plant provides shortage power that would remain otherwise unserved). As we do not have a full demand model for electricity in Ghana that would allow us to estimate the quantity of incremental sales, the analysis in this paper will include only the avoided thermal costs as financial benefits from the project.

From the project point of view (or from the utility standpoint if thermal generation is not an alternative to the hydro facility), the financial benefits are the actual revenues from selling Bui's production at the current tariff structure.

Financial Costs

The financial costs of the plant from both the utility and project viewpoints include the investment cost and the operating and maintenance costs. It is immaterial whether thermal generation is an option or not. In contrast, when an IPP builds and owns the plant, the financial cost of the project from the utility perspective is the actual cost of purchasing electricity from the IPP at the terms specified in the power purchase agreement.

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[10] However, an independent power producer may be interested in assessing the impact of the project on the cash flows of the utility which is purchasing power in order to better prepare its own negotiating position.

[11] For a full discussion, see: Jenkins Glenn and Lim Henry, An Integrated Analysis of a Power Purchase Agreement, Harvard Institute for International Development, 1998.

Financial benefits and costs when an IPP constructs and operates the project

The financial benefits to the IPP are the actual revenues from selling electricity to the utility at the terms specified in the power purchase agreement. The financial benefits will obviously change with the rate of return required by the IPP.

The financial costs to the IPP include the investment cost, operating and maintenance costs, and the income tax liability.

Total Investment and Equ3ity Perspectives

The cash flow statement from each of the previous standpoints can be developed from the total investment and the equity perspectives.

The analysis from the total investment perspective does not take into consideration the financing decisions assumed with the project, except for the estimation of income tax liabilities. This perspective enables the analyst to assess the ability of the project to generate cash flow.

In contrast, the equity perspective determines the cash flow profile of the project when leverage is employed. Included in the cash flow statement are the loan facilities as sources of funds, and the loan repayments as cash outflows[12].

C. Electricity Pricing

The tariff structure for the electricity generated by the project will likely depend on whether VRA or an IPP undertakes the project.

VRA's Tariff Structure

Table 7 shows the tariff charged in 1997 by VRA to foreign and domestic consumers.

[12] For a full discussion see: Harberger Arnold and Jenkins Glenn, Manual for Cost Benefit Analysis of Investment Decisions, Chapter 3, 1996.

Table 7
Tariff Rates in 1997

VALCO & Exports	**(in US$/KWh)**	
VALCO	0.0178	
Communaute Electrique du Benin (CEB) And SINABEL	0.0510	
Domestic Consumers	**(in Cedis/KWh)**	***(Equivalent in US$/KWh)***
Electric Corporation of Ghana (ECG)	24.00	*0.015*
Northern Electric Department (NED)	43.65	*0.027*
Mining/Manufacturing Industries & Others	50.34	*0.031*

With the exception of VALCO's rate, these tariffs are assumed to be adjusted annually to reflect inflation. The rate applied to VALCO, the main consumer in the system is contractually adjusted for US inflation at the end of every five years.

This tariff structure was set when the generation system included only the Akosombo and Kpong hydro plants, and the Tema diesel plant[13]. Under a cost-plus regulatory system, tariffs are set in order to recover the fixed costs (capital cost including an adequate return to equity investors, depreciation and fixed operating and maintenance costs) and the variable costs associated with power production (fuel costs, income tax liability and variable operating and maintenance costs)[14]. However, given the necessity to expand the system by implementing power plants with higher capacity costs, the current rates are too low to recover the incremental financial cost of expansion. As there is a large gap between the current rates and the long-run marginal cost[15], an increase in the tariff levels seems reasonable to expect sometime in the future.

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[13] Akosombo, Tema and Kpong plants have been commissioned in 1965, 1970, and 1984, respectively.
[14] In the case of hydro plants, running costs include only operating and maintenance costs. Typically, these costs are equal to a relatively small portion of the initial construction cost. In addition, the annual power production of a hydro plant can be approximated by its long-term average generation output, making the distinction between fixed and variable operating and maintenance costs not meaningful for tariff calculation.
[15] The current average tariff is 0.021 US$/KWh. The long-run marginal cost of new thermal plants is about 0.061 US$/KWh (see paragraph D).

IPP's Tariff

If it is an IPP that is used to implement the Bui plant, the flat tariff at which the IPP sells electricity to VRA is likely to be set in order to achieve a pre-specified real return on the equity invested. Table 8 shows the different tariffs that an IPP would have to charge VRA for different real rates of return on equity.

Table 8
IPP Tariffs for Different Real Rates of Return on Equity

Required Real Rate of Return on Equity	IPP Tariffs (Cedis/Kwh)	IPP Tariffs (Equivalent in US$/Kwh)
13%	86.41	0.054
15%	95.79	0.060
17%	107.84	0.067

D. Cost of Replaced Thermal Power

As discussed above, from the utility viewpoint the avoided costs to VRA of otherwise generating the power provided by Bui are considered as the financial benefits of the project. When Bui starts operations, the thermal plants run by VRA will include the Takoradi combined cycle and the 200 MW gas turbine plant planned for implementation in 1999. Because of its high fuel and variable operating costs, the gas turbine plant will be used mostly to generate peak power. The lower cost combined cycle plant will be dispatched before the gas turbine plant and for a longer duration, providing also off-peak power. Because the energy generated by the Bui plant is likely to be supplied during both the peak and off-peak hours, the avoided cost of thermal power per Kwh can be estimated by considering the alternative costs of supplying this energy in the future by an expansion of a combination of gas turbine and combined cycle plants. The avoided financial costs of such a combination of peak and off-peak generation can be estimated as follows:

Avoided Financial Costs of Thermal Alternative per KWh

Gas turbine plant		*Combined cycle plant*
{(A + B)/(8760*PLF) + C + D}*PPR	+	{(A' + B')/(8760*PLF') + C' + D'}*(1-PPR)

where:

Gas turbine plant

A = Levelized capital cost (@ VRA's required real return on equity of 12% and 25 years of economic life) = 76.5 US$/Kwh

B = Fixed operating and maintenance costs = 5 US$/Kwh

8760 = Number of hours in a year

PLF (plant load factor, expressing the actual energy generated relative to the maximum potential energy that can be produced) - Taken to be equal to 20%

PPR (ratio between capacity demand during the peak period relative to overall capacity demand) - Taken to be equal to 30%

C = Variable operating and maintenance costs = 0.0055 US$/Kwh

D = Fuel cost = 0.0435 US$/Kwh.

Combined cycle plant

A' = Levelized capital cost (@ required return on equity of 12% and 25 years of economic life) = 102.9 US$/Kwh

B' = Fixed operating and maintenance costs = 7 US$/Kwh

PLF' - Taken to be equal to 85%

C' = Variable operating and maintenance costs = 0.0045 US$/Kwh

D' = Fuel cost = 0.0265 US$/Kwh

The cost of replaced thermal power is estimated at 97.10 Cedis/Kwh (about 0.061 US$/KWh).

E. Methodology

The financial analysis of the project has been conducted in both nominal and real prices to account for the different impacts of inflation. There are both direct and indirect impacts of inflation on the financial viability of a project. The direct impact of inflation on the returns to the project takes place through changes in the real value of accounts receivable, accounts payable and cash balance[16]. The indirect impact, also known as the tax impact, is not relevant for VRA because it does not pay corporate income tax, but it would be if an IPP were to undertake the project. The nominal cash flow statement is then deflated item by item to arrive at the real cash flow statement.

The financial viability of the project is estimated by calculating its net present value (NPV), and by considering the sensitivity of its financial performance to the key variables of the project.

The NPV of the Bui plant is calculated by discounting the real net cash flow profile of the project from the equity holder's perspective at the real rate of return on equity of 12 percent if the project is built directly by the utility and of 15 percent if it is undertaken by an IPP. In addition, if VRA undertakes Bui, part of the debt financing is expected to be obtained at concessionary rates. These concessional funds are assumed not to be available if the project is implemented by an IPP.

F. Results

As mentioned above, definition and measurement of financial costs and benefits depend on: the entity undertaking the financial analysis (VRA or an IPP), the sponsorship of the plant (VRA or an IPP), and the perspective used in the analysis (utility or project). The different results for each possible case are outlined below. Tables 11 through 19 show the cash flow statements in each scenario.

1) VRA conducts the financial analysis of the project as part of its generation strategy

When VRA conducts the financial analysis of the plant, the results of the project depend on the sponsorship of the project (the utility itself or an IPP), on the perspective considered in the analysis, and on the availability of thermal generation as an alternative to the hydro facility.

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[16] An increase in the rate of inflation affects the NPV of the project adversely through the real changes in accounts receivable and cash balance, and improves it through the real changes in accounts payable. For a full discussion of the impacts of inflation on the financial analysis of projects, see: Harberger A. and Jenkins G., "Manual….", Chapter 6, 1995.

Utility point of view (when thermal generation is not an alternative to the project)

The financial benefits of the plant from the utility perspective when thermal generation is not an alternative to the plant (or from the project standpoint) are the actual revenues from selling electricity at the current tariff structure. As mentioned above, VRA is by statute committed to supply the electricity required to meet the market demand for power.

Table 9 summarizes the financial results of the plant from this perspective. The cash flow statements of the plant are shown in Tables 11 through 13. As discussed above, if VRA undertakes the plant, it can expect to obtain part of the project debt financing at a concessionary rate. Notwithstanding the subsidized financing, the NPV of the Bui plant under the current tariff structure is negative (- 90,344 million Cedis corresponding to about -56 million US$). If an IPP were to undertake the plant, the results are considerably worse (with a NPV of –331,970 million Cedis corresponding to about –211 million US$) because of the higher purchase price of electricity from the IPP. These negative results are not surprising, as the current rates are recognized to be low. The ability of VRA to raise power tariffs is, therefore, critical to maintain the financial soundness of the utility as it undertakes its expansion plans.

Table 9
Financial Results from the Utility Perspective
(if Thermal Generation is not an Alternative)

NPV OF THE PROJECT (VRA OWNS BUI) *with low-cost debt financing*	**NPV OF THE PROJECT (AN IPP BUILDS AND OPERATES BUI)** *Non-subsidized debt at nominal 8.5% (equal to 79% of total project cost)*		
- 90,344 million Cedis (about -56.5 million US$)	*Required IPP Real ROE*	*IPP Tariffs (Cedis/Kwh)*	*NPV (in million Cedis)*
	13%	86.41	-281,405 (-176 million US$)
	15%	95.79	-331,970 (-211 million US$)
	17%	107.84	-396,959 (-248 million US$)

<u>*Utility point of view (when thermal generation is an alternative to the project)*</u>

The financial benefits of the Bui plant from the utility standpoint (when thermal generation is the alternative to the plant) are the project sales valued at the avoided cost of the thermal power generation. Table 10 summarizes the financial results of the project from this perspective. The cash flow statements of the plant are shown in Tables 15 through 17. When the utility undertakes the plant, the project is financially viable with a positive NPV of 266 billion Cedis (about 166 million US$). If, instead, an IPP undertakes the plant, the NPV of the project from the utility perspective is marginally positive (about 24 billion Cedis corresponding to 15 million US$), because the thermal cost savings per Kwh (97.1 Cedis/Kwh) are slightly higher than the flat rate at which the utility buys power from the IPP (96.8 Cedis/Kwh at a required real return on equity of 15%). In this case, the viability of the project depends, therefore, on the flat rate charged by the IPP, which, in turn, depends on the real rate of return it requires.

Table 10

Financial Results from the Utility Point of View

(if Thermal Generation is an Alternative to the Project)

NPV OF THE PROJECT (VRA Owns BUI) ***with low-cost debt financing***	**NPV OF THE PROJECT (AN IPP OWNS BUI)** ***Non-subsidized debt at nominal 8.5% (equal to 79% of total project cost)***		
265,686 million Cedis (about 166 million US$)	*Required IPP Real ROE*	*IPP Tariffs (Cedis/Kwh)*	*NPV (in million Cedis)*
	13%	86.41	74,625 (47 million US$)
	15%	95.79	24,060 (15 million US$)
	17%	107.84	-40,929 (-26 million US$)

2) An IPP sponsors the project

Tables 18 and 19 show the cash flow statements of the Bui plant in the scenario where it is an IPP to sponsor the construction and operation of the project. In this case the tariff charged to the utility is exactly set in order to generate a pre-specified real return to the equity invested by the IPP (15%) and the minimum NPV of the project will obviously be zero.

TABLE 11

VRA Point of View - Revenues Reflect Current Tariffs - VRA OWNS BUI PLANT

CASH FLOW STATEMENT, Real (1997 prices)

Total Investment (in million Cedis)

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS																
Net sales -																
Domestic						19364	29047	29047	29047	29047	29047	29047	29047	29047	29047	
Export						6119	9043	8912	9317	9178	9043	8912	9178	8912	9178	
Change in accounts receivable						-4256	-2956	-1250	-1335	-1258	-1254	-1250	-1258	-1250	-1258	5107
Liquidation value -																
Land																23711
Dam & civil works																65700
																0
Cash Inflow						21227	35133	36708	37028	36966	36835	36708	36966	36708	36966	94517
EXPENDITURES																
Investment cost -																
Land	31614															
Preparatory works																
and construction facilities	28284	20602														
Civil works																
Diversion	1947	2156	3442	1723	860											
Main dam	31589	35648	56911	28505	14230											
Saddle dam	3257	3606	5758	2884	1440											
Power station	4805	5320	8493	4254	2124											
Hydro-electromechanical equipment			0	0	0											
Powerhouse equipment	14495	12822	19512	22300	6690								45000			
Water intake	87	77	115	134	39											
Power intakes	3495	3080	4629	5387	1548											
Spillway	2242	1975	2962	3456	987											
Administration & engineering	5613	11657	17269	17269	5613											
Interconnection with the transmission grid																
161 kv line		8961	13010	16362												
Substations equipment		1492	2166	2724												
Administration & engineering		1472	2138	2693												
Environmental impact																
Reforestation	1600	1600	1600	1600	1600											
Resettlement	700	700	700	700	700											
Infrastructure	100	100	100	100	100											
Operating costs -																
Generation						1086	1086	1086	1086	1086	1086	1086	1086	1086	1086	
Transmission						743	743	743	743	743	743	743	743	743	743	
Distribution						233	233	233	233	233	233	233	233	233	233	
Administration						806	822	839	855	872	890	1063	1296	1580	1926	
Township						140	140	140	140	140	140	140	140	140	140	
Health & Safety						109	109	109	109	109	109	109	109	109	109	
Change in accounts payable						-521	-107	-107	-108	-109	-109	-115	-124	-134	-147	566
Change in cash balance						312	64	64	65	65	65	69	74	80	88	-339
Cash Outflow	129829	111268	138806	110091	35931	2908	3090	3106	3123	3140	3157	3328	48558	3837	4179	227
NET CASH FLOW	-129829	-111268	-138806	-110091	-35931	18319	32043	33602	33905	33826	33678	33380	-11591	32871	32788	94290

TABLE 12

VRA Point of View -VRA OWNS BUI PLANT - Revenues Reflect Current Tariffs

CASH FLOW STATEMENT, Real (1997 prices)

Equity Holder (in million Cedis)

		1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
Net cash flow before financing		-129829	-111268	-138806	-110091	-35931	18319	32043	33602	33905	33826	33678	33380	-11591	32871	32788	94290
Debt financing																	
IDA		44151	50581	64007	51761	15786		-21037	-20424	-19830	-19252	-18691	-14325				
EIB		11418	13081	16553	13386	4083		-3819	-3708	-3600	-3495	-3393	-2601				
Export credits & Others		20553	23546	29796	24096	7349		-14609	-14184	-13771	-13370	-12980	-9948				
Total debt cash flow		76123	87209	110357	89243	27217		-39466	-38316	-37200	-36117	-35065	-26874				
Net cash flow after debt fin.		-53706	-24059	-28450	-20848	-8713	18319	-7423	-4714	-3295	-2290	-1386	6506	-11591	32871	32788	94290
	0																
NPV @	***12.00%***	***-90344***															

TABLE 13

VRA Point of View -IPP OWNS BUI PLANT - Revenues Reflect Current Tariffs

CASH FLOW STATEMENT, Real (1997 prices)

(in million Cedis)

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS											
Net sales -											
Domestic	19364	29047	29047	29047	29047	29047	29047	29047	29047	29047	0
Export	6119	9043	8912	9317	9178	9043	8912	9178	8912	9178	0
Change in accounts receivable	-4256	-2956	-1250	-1335	-1258	-1254	-1250	-1258	-1250	-1258	5107
Cash Inflow	21227	35133	36708	37028	36966	36835	36708	36966	36708	36966	5107
EXPENDITURES											
Power Purchase from IPP	71233	106850	106850	106850	106850	106850	106850	106850	106850	106850	0
Accounts payable	-11896	-8327	-3569	-3569	-3569	-3569	-3569	-3569	-3569	-3569	14275
Cash Outflow	59337	98523	103281	103281	103281	103281	103281	103281	103281	103281	14275
NET CASH FLOW	-38110	-63389	-66572	-66253	-66315	-66445	-66572	-66315	-66572	-66315	-9168

NPV @ ***12.00%*** ***-331970***

TABLE 14

VRA Point of View -IPP OWNS BUI PLANT - Revenues Reflect Current Tariffs

Gas turbine plant using distillate fuel oil (GT)			***Combined cycle plant***		
Annual capital cost	600	US$/Kwh	Annual capital cost	807	US$/Kwh
Fixed operating & maintenance costs (B)	5	US$/Kwh	Fixed operating & maintenance costs (B)	7	US$/Kwh
Plant load factor	20%		Plant load factor	85%	
Variable operating & maintenance costs (C)	0.0055	US$/Kwh	Variable operating & maintenance costs (	0.0045	US$/Kwh
Fuel cost (D)	0.0435	US$/Kwh	Fuel cost (D)	0.0265	US$/Kwh
Income tax (E)	0.0025	US$/Kwh	Income tax (E)	0.0075	US$/Kwh
Levelized ca (@ 15% and 25 years of ec. life)	92.82	US$/Kwh	Levelized capital cost (A)	124.84	US$/Kwh
(A + B)/(8760*PLF)	0.0558	US$/Kwh	(A + B)/(8760*PLF)	0.018	

*IPP rate @ 15% [((A + B) / 8760*PLF) + C + D + E] * PPR* *0.0322 US$/Kwh* *IPP rate @ 15% [((A + B) / 8760*PLF) + C + D + E] *(1 - PPR)* *0.039 US$/Kwh*

IPP rate @ 15% ***0.0715*** **US$/Kwh** **=** ***114.5 Cedis/Kwh***

CASH FLOW STATEMENT, Real (1997 prices)

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS											
Net sales -											
Domestic	19364	29047	29047	29047	29047	29047	29047	29047	29047	29047	
Export	6119	9043	8912	9317	9178	9043	8912	9178	8912	9178	
Change in accounts receivable	-4256	-2956	-1250	-1335	-1258	-1254	-1250	-1258	-1250	-1258	5107
Cash Inflow	21227	35133	36708	37028	36966	36835	36708	36966	36708	36966	5107
EXPENDITURES											
Power Purchase from IPP	85128	127693	127693	127693	127693	127693	127693	127693	127693	127693	
Accounts payable	-14216	-9952	-4265	-4265	-4265	-4265	-4265	-4265	-4265	-4265	17060
Cash Outflow	70912	117741	123428	123428	123428	123428	123428	123428	123428	123428	17060
NET CASH FLOW	-49685	-82608	-86719	-86400	-86461	-86592	-86719	-86461	-86719	-86461	-11953

NPV @ ***12.00%*** ***-432691***

TABLE 15

UTILITY PERSPECTIVE - VRA OWNS BUI PLANT - Revenue Based on Thermal Cost Savings

CASH FLOW STATEMENT, Real (1997 prices)

Total Investment (in million Cedis)

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS																
Thermal cost savings						72209	108313	108313	108313	108313	108313	108313	108313	108313	108313	0
Change in accounts receivable						-4256	-2956	-1250	-1335	-1258	-1254	-1250	-1258	-1250	-1258	5107
Liquidation value -																
Land																23711
Dam & civil works																65700
Cash Inflow						67953	105357	107063	106978	107055	107059	107063	107055	107063	107055	94517
EXPENDITURES																
Investment cost -																
Land	31614															
Preparatory works																
and construction facilities	28284	20602														
Civil works																
Diversion	1947	2156	3442	1723	860											
Main dam	31589	35648	56911	28505	14230											
Saddle dam	3257	3606	5758	2884	1440											
Power station	4805	5320	8493	4254	2124											
Hydro-electromechanical equipment			0	0	0											
Powerhouse equipment	14495	12822	19512	22300	6690								45000			
Water intake	87	77	115	134	39											
Power intakes	3495	3080	4629	5387	1548											
Spillway	2242	1975	2962	3456	987											
Administration & engineering	5613	11657	17269	17269	5613											
Interconnection with the transmission grid																
161 kv line		8961	13010	16362												
Substations equipment		1492	2166	2724												
Administration & engineering		1472	2138	2693												
Environmental impact																
Reforestation	1600	1600	1600	1600	1600											
Resettlement	700	700	700	700	700											
Infrastructure	100	100	100	100	100											
Operating costs -																
Generation						1086	1086	1086	1086	1086	1086	1086	1086	1086	1086	
Transmission						743	743	743	743	743	743	743	743	743	743	
Distribution						233	233	233	233	233	233	233	233	233	233	
Administration						806	822	839	855	872	890	1063	1296	1580	1926	
Township						140	140	140	140	140	140	140	140	140	140	
Health & Safety						109	109	109	109	109	109	109	109	109	109	
Change in accounts payable						-521	-107	-107	-108	-109	-109	-115	-124	-134	-147	566
Change in cash balance						312	64	64	65	65	65	69	74	80	88	-339
Cash Outflow	129829	111268	138806	110091	35931	2908	3090	3106	3123	3140	3157	3328	48558	3837	4179	227
NET CASH FLOW	-129829	-111268	-138806	-110091	-35931	65045	102267	103956	103855	103915	103902	103735	58497	103225	102877	94290

TABLE 16

UTILITY PERSPECTIVE - VRA OWNS BUI PLANT - Revenue Based on Thermal Cost Savings

CASH FLOW STATEMENT, Real (1997 prices)

Equity Holder (in million Cedis)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2016	2026	2036	2046	2047
Net cash flow before financing		-129829	-111268	-138806	-110091	-35931	65045	102267	103956	103855	103915	103902	103735	58497	103225	102877	94290
Debt financing																	
IDA		44151	50581	64007	51761	15786		-21037	-20424	-19830	-19252	-18691	-14325				
EIB		11418	13081	16553	13386	4083		-3819	-3708	-3600	-3495	-3393	-2601				
Export credits & Others		20553	23546	29796	24096	7349		-14609	-14184	-13771	-13370	-12980	-9948				
Total debt cash flow		76123	87209	110357	89243	27217		-39466	-38316	-37200	-36117	-35065	-26874				
Net cash flow after debt fin.		-53706	-24059	-28450	-20848	-8713	65045	62801	65640	66655	67799	68837	76861	58497	103225	102877	94290
NPV @	***12.00%***	***265686***															

TABLE 17

UTILITY PERSPECTIVE - IPP OWNS BUI PLANT - Revenue Based on Thermal Cost Savings

CASH FLOW STATEMENT, Real (1997 prices)

(in million Cedis)

	2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS											
Thermal cost savings	72209	108313	108313	108313	108313	108313	108313	108313	108313	108313	
Change in accounts receivable	-4256	-2956	-1250	-1335	-1258	-1254	-1250	-1258	-1250	-1258	5107
Cash Inflow	67953	105357	107063	106978	107055	107059	107063	107055	107063	107055	5107
EXPENDITURES											
Power Purchase from IPP	71233	106850	106850	106850	106850	106850	106850	106850	106850	106850	
Accounts payable	-11896	-8327	-3569	-3569	-3569	-3569	-3569	-3569	-3569	-3569	14275
Cash Outflow	59337	98523	103281	103281	103281	103281	103281	103281	103281	103281	14275
NET CASH FLOW	8616	6834	3782	3697	3774	3778	3782	3774	3782	3774	-9168

NPV @ 12.00% 24060

TABLE 18

IPP POINT OF VIEW - IPP OWNS BUI PLANT - Revenues Based on Minimum Rate of Return

CASH FLOW STATEMENT, Real (1997 prices)

Total Investment (in million Cedis)

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
RECEIPTS																
Net sales -																
Sales to VRA						71233	106850	106850	106850	106850	106850	106850	106850	106850	106850	0
Change in accounts receivable						-11896	-8327	-3569	-3569	-3569	-3569	-3569	-3569	-3569	-3569	14275
Liquidation value -						0	0	0	0	0	0	0	0	0	0	0
Land						0	0	0	0	0	0	0	0	0	0	23711
Dam & civil works						0	0	0	0	0	0	0	0	0	0	65700
Cash Inflow						59337	98523	103281	103281	103281	103281	103281	103281	103281	103281	103686
EXPENDITURES																
Investment cost -																
Land	31614	0	0	0	0											
Preparatory works	0	0	0	0	0											
and construction facilities	28284	20602	0	0	0											
Civil works	0	0	0	0	0											
Diversion	1947	2156	3442	1723	860											
Main dam	31589	35648	56911	28505	14230											
Saddle dam	3257	3606	5758	2884	1440											
Power station	4805	5320	8493	4254	2124											
Hydro-electromechanical equipment	0	0	0	0	0											
Powerhouse equipment	14495	12822	19512	22300	6690											
Water intake	87	77	115	134	39											
Power intakes	3495	3080	4629	5387	1548											
Spillway	2242	1975	2962	3456	987											
Administration & engineering	5613	11657	17269	17269	5613											
Interconnection with the transmission grid																
161 kv line		8961	13010	16362												
Substations equipment		1492	2166	2724												
Administr. & engineering		1472	2138	2693												
Environmental impact																
Reforestation	1600	1600	1600	1600	1600											
Resettlement	700	700	700	700	700											
Infrastructure	100	100	100	100	100											
Operating costs -																
Generation						1086	1086	1086	1086	1086	1086	1086	1086	1086	1086	
Transmission						743	743	743	743	743	743	743	743	743	743	
Distribution						233	233	233	233	233	233	233	233	233	233	
Administration						806	822	839	855	872	890	1063	1296	1580	1926	
Township						140	140	140	140	140	140	140	140	140	140	
Health & Safety						109	109	109	109	109	109	109	109	109	109	
Income tax liability						0	5772	24263	26768	28995	32665	44958	47482	47361	47202	
Change in accounts payable						-521	-107	-107	-108	-109	-109	-115	-124	-134	-147	566
Change in cash balance						312	64	64	65	65	65	69	74	80	88	-339
Cash Outflow	129829	111268	138806	110091	35931	2908	8862	27369	29891	32135	35822	48286	51040	51198	51380	227
NET CASH FLOW	-129829	-111268	-138806	-110091	-35931	56429	89660	75912	73390	71146	67459	54995	52241	52083	51901	103459

TABLE 19

IPP POINT OF VIEW - IPP OWNS BUI PLANT - Revenues Based on Minimum Rate of Return

CASH FLOW STATEMENT, Real (1997 prices)

Equity Holder (in million Cedis)

		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2016	2026	2036	2046	2047
Net cash flow before financing		-129829	-111268	-138806	-110091	-35931	56429	89660	75912	73390	71146	67459	54995	52241	52083	51901	103459
Debt financing		76123	87209	110357	89243	27217	0	-54109	-52533	-51003	-49517	-48075	-36845				
Net cash flow after debt fin.		-53706	-24059	-28450	-20848	-8713	56429	35551	23379	22387	21629	19384	18149	52241	52083	51901	103459
NPV @	***15.00%***	***0***															

7. Sensitivity Analysis on the Financial Results

A sensitivity analysis is conducted to identify the variables that most likely affect the financial outcomes of the Bui project, and to quantify the extent of these impacts. Tables 20 through 24 present the results of the sensitivity analysis for the following variables: domestic inflation rate, investment cost overrun, electricity generation, peak power ratio, and change in real fuel cost.

Domestic inflation rate

The impacts of different levels of domestic inflation on the financial NPVs of the project in the scenarios where either VRA[17] or an IPP implements the analysis of the Bui plant are shown in Table 20.

Table 20
Sensitivity of Financial NPVs to Inflation Rate

Inflation Rate	**Financial NPV - VRA - (million Cedis)**	**Financial NPV - IPP - (million Cedis)**
15%	-88,408	18,622
20%	-89,416	6,701
25%	*-90,344*	*0*
30%	-91,201	-5,070
35%	-91,994	-9,230
40%	-92,730	-12,737
45%	-93,416	-15,744

In the scenario where it is VRA to implement the project, the overall impact of inflation on the project NPV is relatively small, primarily because the project does not pay income tax. A 20 percentage point increase of domestic inflation would lower the NPV of the project by about 3 billion Cedis (a change of only -3.7 percent). This reduction in the project's financial

[17] The sensitivity analysis has been conducted on the NPV from the project perspective in the scenario where it is VRA to undertake the plant.

NPV reflects the impact of inflation on the real changes in the amount of working capital required by the plant[18].

On the other hand, in the scenario where it is an IPP to sponsor the project, the impact of inflation is large because the project would pay income tax. A 20 percent increase of domestic inflation would lower the NPV of the project by about 16 billion Cedis.

Investment cost overrun

The financial viability of the project is highly sensitive to the likelihood of a higher than anticipated investment cost. As shown in Table 21, a cost over-run of 20% reduces the financial NPV of almost 82 billion Cedis (about US$ 52 million). As mentioned above, the cost estimates for the Bui plant are based on the experience of similar projects implemented in the region after international bidding, and include a cost contingency provision. Cost overruns above the contingency levels in Ghana, however, cannot be excluded.

Table 21
Sensitivity of Financial NPVs to Investment Cost Over-runs

Divergence from Original Cost Estimate	Financial NPV - VRA - (million Cedis)
0%	*-90,344*
5%	-110,815
10%	-131,285
15%	-151,756
20%	-172,226
25%	-192,697
30%	-213,167

Electricity generated (water risk)

Table 22 shows that the economic results of the project are sensitive to changes in the annual amount of power generated by the plant. A reduction of the annual level of generation

[18] An increase in the rate of inflation affects the project returns adversely through the changes in accounts

to 75 percent of the deterministic value (1150 Gwh) would result in a drop of the financial NPV from the utility perspective by about 135 billion Cedis (84 million US$).

Table 22
Sensitivity of Financial NPV
to Energy Generation Factor

Energy Generation as a % of the Deterministic Value	**Financial NPV - VRA - project perspective (million Cedis)**	**Financial NPV - VRA - utility perspective (million Cedis)**
65%	-154,875	76,317
70%	-145,656	103,282
75%	-136,437	130,247
80%	-127,219	157,212
85%	-118,000	184,177
90%	-108,781	211,142
95%	-99,563	238,106
100%	*-90,344*	*265,686*

Peak Power Ratio

As discussed above, the cost of generating electricity is higher during the peak period than during the off-peak hours. This higher generating cost arises from the higher fuel cost as well as the higher capacity cost per hour of the plants used to supply peak power (typically gas-turbine plants).

The peak power generation ratio (ratio between capacity demand during the peak period relative to overall capacity demand) affects the financial valuation of the thermal power replaced by the Bui project. The higher is the peak power ratio (PPR), the larger are the avoided costs to VRA of generating the peak-time power by means of the high fuel cost gas-turbine plant[19]. As shown in Table 23, a reduction of PPR from the expected 30 percent to 20

receivable and in cash balances, and improves it through changes in accounts payable.

[19] Without the Bui plant, it is assumed that the gas turbine plant with its higher fuel costs will be mostly used to generate peak power. The lower fuel cost combined cycle plant will primarily provide off-peak power.

percent would result in a decrease of the financial NPV from the utility perspective of 45 billions Cedis (corresponding to a change of -17 percent).

Table 23
Sensitivity of Financial NPV to Peak Power Ratio

Peak Power Ratio	Financial NPV - VRA - utility perspective (million Cedis)
15%	197,470
20%	220,004
25%	242,537
30%	*265,686*
35%	287,605
40%	310,139
45%	332,673

Real Fuel Costs

Fuel cost is among the main components of the overall cost of thermal power generation. Changes in the real cost of fuel have, therefore, an impact on the financial return of a hydro plant from the utility perspective. Table 24 shows that the financial results of the project are sensitive to changes in the value of this variable. A 10 percent decrease in the real cost of fuel would lower the financial NPV of the project by about 29 billion Cedis (a change of -11 percent).

Table 24
Sensitivity of Financial NPV to % Change in Average Real Fuel Cost

% Change in Real Fuel Cost	Financial NPV - VRA - utility perspective (million Cedis)
-30%	179,210
-20%	207,831
-10%	236,451
0%	*265,686*
10%	293,691
20%	322,312
30%	350,932

8. Tariff Analysis

As discussed above, the implementation of the Bui project would cause the VRA to lose money with the current tariff structure (from the utility standpoint, when thermal generation is not a possible alternative to the hydro facility). A number of simulations have been conducted in this study to show how much the tariff structure might be changed so that VRA's overall sales would enable the utility to pay for the project. As the export tariff to CEB and SINABEL is already relatively high (0.051 US$/Kwh), the analysis has regarded only the rates charged to domestic customers and to the large multinationally owned aluminum smelter, VALCO. The simulations have been conducted for both the cases where either the utility or an IPP undertakes the project. Three alternative scenarios have been considered in each case: 1) all domestic tariffs are changed, 2) only VALCO's rate is adjusted, and 3) all domestic tariffs excluding VALCO's one are modified. The results of the simulations are outlined below.

1) VRA undertakes the Bui project

As discussed above, if VRA undertakes the plant, it can expect to obtain part of the project's debt financing at a concessionary rate. Therefore, two alternative scenarios have been considered in the analysis: 1) VRA is able to secure financing at a concessionary rate, and 2) VRA cannot obtain subsidized financing.

Changes in all domestic tariffs (excluding VALCO's)

If VRA obtains part of the project debt financing at a concessionary rate, an increase of all domestic tariffs (excluding VALCO's) of 9.31% is sufficient to pay for the Bui project. Otherwise, domestic tariffs have to be raised by 12.93%. Table 25 shows the tariff structure (disaggregated by groups of domestic customers) that would enable VRA to pay for the project.

Table 25
Break-even in Domestic Tariffs (excluding VALCO's)

	NPV @ current Tariff structure (in million Cedis)	Required new minimum tariffs (1997 price level)			% increase in tariff from base case
		ECG (Cedis/Kwh)	NED (Cedis/Kwh)	Min./Manuf. & Others (Cedis/Kwh)	
Current tariffs		24.0	43.65	50.34	
With subsidized capital	-90,344	26.2	47.7	55	9.31%
With non-subsidized capital	-125,512	27.1	49.3	56.8	12.93%

Changes in VALCO's tariff only

As shown in Table 26, if it was the policy to finance the financial losses caused by the Bui plant through an increase in VALCO's tariff alone, its tariff would need to be increased by 23% if VRA could secure debt financing at a concessionary rate. Otherwise, if the concessionary financing were not available, the VALCO tariff would need to be raised by about 32%.

Table 26
Break-even in VALCO's Tariff Only

	Current Tariff (Cedis/Kwh)	New minimum tariff – 1997 prices (Cedis/Kwh)	% increase in tariff from base case
With subsidized capital	28.48	35	22.89%
With non-subsidized capital	28.48	37.5	31.80%

Changes in all domestic tariffs (including VALCO's)

As shown in Table 27, domestic tariffs have to be increased by 7% if VRA can obtain subsidized debt financing. Otherwise, the percentage increase has to be about 9.2%.

It can also be noticed that, in this case, the percentage increase in the tariff structure that is sufficient to pay for the project is lower than the one required in the two precedent cases.

Table 27
Break-even in All Domestic Tariffs (including VALCO's)

	Required new minimum tariffs (1997 price level)				% increase in tariff from base case
	VALCO (US$/Kwh)	**ECG (Cedis/Kwh)**	**NED (Cedis/Kwh)**	**Min./Manuf. & Others (Cedis/Kwh)**	
Current Tariffs	28.48	24.0	43.65	50.34	
With subsidized capital	30.4	25.6	46.5	53.7	6.62%
With non-subsidized capital	31.1	26.2	47.7	55.0	9.19%

2) An IPP undertakes the Bui project

The percentage increase in the tariff structure that would enable VRA to pay for the project in the scenario where it is an IPP to undertake Bui is considerably higher than that required when VRA itself builds the plant. This is because VRA's current average tariff (33.6 Cedis/Kwh) is much lower than the flat tariff VRA would need to pay for electricity it buys from the IPP (96.8 Cedis/Kwh). As discussed above, this flat tariff is the result of the specific assumptions used in the analysis to develop the model for the IPP case, namely: 1) the IPP requires a higher rate of return on equity than VRA (assuming, however, that both face the same physical project cost), 2) differently from VRA, the IPP pays income tax, and 3) differently from VRA, the IPP has no access to debt financing at concessionary rates.

Changes in all domestic tariffs (excluding VALCO's)

As shown in Table 28, an increase of 34% in all domestic tariffs excluding the one charged to VALCO would be sufficient to enable VRA to pay for the Bui project (as compared to about 10% in the scenario where it is VRA that builds the plant).

Table 28
Break-even in Domestic Tariffs (excluding VALCO's)

	ECG (Cedis/Kwh)	**NED (Cedis/Kwh)**	**Min./Manuf. & Others (Cedis/Kwh)**	**% increase in tariff from base case0**
Current tariff	24.0	43.65	50.34	
Required minimum new tariff (1997 prices)	32.2	58.6	67.6	34.20%

Changes in VALCO's tariff only

As shown in Table 29, if VALCO were to pay all of the marginal financing costs of the new power project with IPP financing, VALCO's tariff has to be increased by about 84% (as compared to about 23% in the previous case).

Table 29
Break-even in VALCO's Tariff Only

Current Tariff (Cedis/Kwh)	New minimum tariff (Cedis/Kwh)	% increase in tariff from base case
28.48	52.4	84.12%

Changes in all domestic tariffs (including VALCO's)

As shown in Table 30, an increase in all domestic tariffs of 24% would enable VRA to pay for the Bui project (as compared to 7% in the alternative scenario).

Table 30
Break-even in All Domestic Tariffs (including VALCO's)

	VALCO (Cedis/Kwh)	ECG (Cedis/Kwh)	NED (Cedis/Kwh)	Min./Manuf. & Others (Cedis/Kwh)	% increase in tariff from base case
Current tariffs	28.48	24.0	43.65	50.34	
Required minimum new tariff (1997 prices)	35.4	29.8	54.3	62.6	24.31%

3) An IPP undertakes a thermal plant

This analysis has been developed under the assumption that an IPP undertakes investments similar to the Takoradi combined cycle and the 200 MW gas turbine plant planned for implementation in 1999 (at the same project cost profile as for VRA plus income tax) as a substitute for building Bui. The flat tariff at which the IPP sells electricity to VRA is estimated at 114.5 Cedis/Kwh (about 0.072 US$/Kwh) on the basis of the IPP's required real return on equity of 15%.

Changes in all domestic tariffs (excluding VALCO's)

As shown in Table 31, an increase in all domestic tariffs (excluding VALCO's) of 45% would be sufficient to enable VRA to pay for the thermal plant (as compared to about 34% in the scenario where the IPP builds Bui).

Table 31
Break-even in Domestic Tariffs (excluding VALCO's)

	ECG (Cedis/Kwh)	NED (Cedis/Kwh)	Min./Manuf. & Others (Cedis/Kwh)	% increase in tariff from base case
Current tariff	24.0	43.65	50.34	
Required minimum new tariff (1997 prices)	34.7	63.1	72.8	44.6%

Changes in VALCO's tariff only

As shown in Table 32, VALCO's tariff has to be increased by about 110% (as compared to about 84% in the alternative scenario), if it were to bear all the additional financial costs of the thermal althernative.

Table 32
Break-even in VALCO's Tariff Only

Current Tariff (Cedis/Kwh)	New minimum tariff (Cedis/Kwh)	% increase in tariff from base case
28.48	59.7	109.6%

Changes in all domestic tariffs (including VALCO's)

As shown in Table 33, an increase in all domestic tariffs by 32% would enable VRA to pay for an IPP built thermal plant (as compared to 24% in the alternative scenario).

Table 33
Break-even in All Domestic Tariffs (including VALCO's)

	VALCO (Cedis/Kwh)	ECG (Cedis/Kwh)	NED (Cedis/Kwh)	Min./Manuf. & Others (Cedis/Kwh)	% increase in tariff from base case
Current tariffs	28.48	24.0	43.65	50.34	
Required minimum new tariff (1997 prices)	37.5	31.6	57.5	66.3	31.7%

Conclusion

The degree to which VRA can adjust its tariff structure is an important determinant of VRA's financial health as it undertakes further investment for expansion. The precedent analysis of the tariff structure shows the requirements under each scenario. As a result of this analysis, it appears that building Bui with subsidized financing requires a relatively small adjustment in tariff. The option of an independent power producer undertaking the project entails a financial burden that someone has to bear, either the government or the consumers. The last option of an IPP built thermal plant to meet the growth in the demand for electricity increases that financial burden even further.

9. Economic Analysis

The measurement of economic benefits and costs is built on the information developed in the financial appraisal, using as a numeraire the domestic currency at the domestic price level.

The economic analysis of the project requires the calculation of the value of the national economic parameters (capital and foreign exchange), the economic value of the electricity generated, and the economic conversion factors for all the inputs used. These are then used to convert the cash flow statement into the statement of economic benefits and costs.

A. National Parameters

1. Economic cost of foreign exchange

The economic exchange rate (E^e) is found to be 10.71% higher than the market exchange rate. The premium on the market exchange rate is due to the impact of the net import tariffs and export taxes.

2. Economic cost of capital

The economic cost of capital (EOCK) for Ghana is estimated to be equal to 12.12%. The EOCK is calculated as a weighted average of the different domestic net-of-tax yields on private savings, the gross-of-tax returns on investment in the separate sectors, and the marginal cost of foreign borrowing[20].

B. The Economic Value of Electricity Generated

The economic benefits of a hydro-electric plant when thermal generation is an alternative to the project include: 1) the economic value of the avoided thermal costs; and 2) the economic value of the shortage power provided (if the plant provides shortage power that would remain otherwise unserved). This study will consider only the economic value of the avoided thermal costs as the economic benefit of the electricity generated.

As discussed above, the financial avoided thermal cost per Kwh has been calculated to determine the financial benefits of the project from the utility perspective. Here the economic benefit of the electricity generated by the project is calculated as being equal to the financial avoided thermal cost per Kwh (97.1 Cedis/Kwh) adjusted by the foreign exchange premium (10.71%) on the traded goods component. The economic value of electricity generated by the Bui project is, therefore, 107.5 Cedis/Kwh (about 0.067 US$/Kwh).

C. Conversion Factors for Inputs

The preliminary step in the calculation of the economic cost of the project inputs is the computation of the conversion factors for the basic components of the investment and operating

[20] For a full discussion of the methodology, see: Jenkins G. and El-Hifnawi B.M., cit., Chapter 3.

costs. These items are, first, divided between tradeable and non-tradeable goods[21]. The economic cost and conversion factors for each of these items are then estimated following the Harberger/Jenkins methodology[22]. Conversion factors for different types of labor employed in the project (managerial, administrative, skilled, unskilled, and foreign)[23] are also calculated.

After determining the basic conversion factors, the economic cost of the project inputs are calculated as the weighted average of the economic value of the basic components. The weights are given by the share of the cost of the basic items in the total cost.

The conversion factors for changes in cash balances are taken to be equal to 1. The conversion factor for changes in accounts payable, equal to 0.910, is given by the weighted average of the conversion factors for the operating and maintenance costs.

D. Results

The statement of the economic benefits and costs for the Bui plant is obtained by adjusting its respective real financial cash flow statement. The profile of economic values for each line item in the economic statement of benefits and costs is obtained by multiplying each line item in the real financial cash flow statement by the corresponding conversion factors.

The economic appraisal is conducted regardless of the entity undertaking the analysis, because the economic benefits of the electricity generated by the project are the same in both the VRA and IPP scenarios.

As shown in Tables 34, the economic NPV of the project using an economic cost of capital of 12.12% is equal to 147,304 million Cedis (about 92 million US$). Therefore, the Bui project, if implemented under either VRA or an IPP sponsorship, would add to the net wealth of Ghana.

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[21] The tradeable goods used by the project are: equipment and machinery, cement, cables, fuel and general materials. Non-tradeable goods include freight, handling, and general non-tradeable materials.
[22] Harberger A., Jenkins G., "Manual…", Chapters 7 - 9.
[23] For a full discussion of the methodology for the calculation of the economic opportunity cost of labor, see: Harberger A., Jenkins G., "Manual…", Chapter 13. VRA is considered protected sector.

TABLE 34: STATEMENT OF ECONOMIC BENEFITS AND COSTS, Real (1997 prices)
(in million Cedis)

	Conversion Factors	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2016*	*2026*	*2036*	*2046*	*2047*
ECONOMIC BENEFITS																	
Economic benefit of replaced thermal power							79945	119917	119917	119917	119917	119917	119917	119917	119917	119917	
Change in accounts receivable							-13351	-6675									20026
Liquidation value -																	0
Land	1.000																23711
Dam & civil works	0.926																60838
Total Benefits							66594	113242	119917	119917	119917	119917	119917	119917	119917	119917	104575
ECONOMIC COSTS																	
Investment cost -																	
Land	1.000	31614															
Preparatory works																	
and construction facilities	0.982	27766	20225														
Civil works																	
Diversion	0.957	1863	2063	3293	1649	823											
Main dam	0.952	30083	33949	54198	27146	13552											
Saddle dam	0.952	3101	3432	5481	2745	1370											
Power station	0.952	4576	5065	8087	4050	2022											
Hydro-electromechanical equipment																	
Powerhouse equipment	1.070	15505	13716	20872	23854	7156								48136			
Water intake	1.074	94	82	124	144	41											
Power intakes	1.049	3667	3232	4857	5652	1625											
Spillway	1.057	2370	2088	3132	3654	1044											
Administration & engineering	0.823	4621	9598	14220	14220	4621											
Interconnection with the transmission grid																	
161 kv line	0.923		8271	12009	15102												
Substations equipment	1.029		1535	2229	2803												
Administr. & engineering	0.857		1261	1832	2308												
Environmental impact																	
Reforestation	0.939	1502	1502	1502	1502	1502											
Resettlement	0.955	669	669	669	669	669											
Infrastructure	0.985	99	99	99	99	99											
Operating costs -																	
Generation	0.973						1057	1057	1057	1057	1057	1057	1057	1057	1057	1057	0
Transmission	0.944						702	702	702	702	702	702	702	702	702	702	0
Distribution	0.878						205	205	205	205	205	205	205	205	205	205	0
Administration	0.840						677	690	704	718	732	747	893	1088	1327	1617	0
Township	0.904						127	127	127	127	127	127	127	127	127	127	0
Health & Safety	0.904						99	99	99	99	99	99	99	99	99	99	0
Change in accounts payable	0.910						-474	-97	-98	-98	-99	-99	-105	-113	-122	-133	515
Change in cash balance	1.000						312	64	64	65	65	65	69	74	80	88	-339
Total Costs		127530	106788	132602	105596	34524	2703	2845	2859	2873	2887	2902	3045	51375	3473	3760	176
NET ECONOMIC BENEFITS		-127530	-106788	-132602	-105596	-34524	63891	110396	117058	117044	117030	117016	116872	68543	116444	116157	104399
NPV @	***12.12%***			***147304***													

10. Sensitivity Analysis on the Economic Results

A sensitivity analysis is conducted to identify the variables that most likely affect the outcomes of the Bui project from the economic perspective. Tables 35 through 39 present the results of the sensitivity analysis for the following variables: investment cost overruns, the quantity of electricity generated, the peak power ratio, and change in the average real fuel cost.

Investment cost overrun

The economic viability of the project is highly sensitive to the likelihood of a higher than anticipated investment cost. As shown in Table 35, a cost over-run of 20% reduces the economic NPV by more than half to about 69 billion Cedis.

Table 35
Sensitivity of Economic NPV to Investment Cost Over-runs

Divergence from Original Cost Estimate	Economic NPV - VRA - (million Cedis)
0%	*147,304*
5%	127,634
10%	107,963
15%	88,291
20%	68,622
25%	48,951
30%	29,281

Electricity generation (water risk)

Table 36 shows that the economic results of the project are sensitive to changes in the annual amount of power generated by the plant. A reduction of the annual level of generation to 74 percent of the deterministic value (1150 Gwh) would result in a negative economic NPV.

Table 36
Sensitivity of Economic NPV
to Energy Generation Factor

Energy Generation as a % of the Deterministic Value	Economic NPV - VRA - (million Cedis)
65%	-58,872
70%	-29,418
75%	35
80%	29,489
85%	58,943
90%	88,397
95%	117,850
100%	*147,304*

Peak Power Ratio

The peak power generation ratio affects the economic (as well as the financial) valuation of the thermal power replaced by the Bui project. The higher is the peak power ratio (PPR), the larger are the avoided costs to VRA of generating the peak-time power by means of the high fuel cost gas-turbine plant[24]. As shown in Table 37, a reduction of PPR from the expected 30 percent to 20 percent would result in a decrease of the economic NPV of 49 billion Cedis (corresponding to a change of -32 percent).

[24] Without the Bui plant, it is assumed that the high fuel cost gas turbine plant will be mostly used to generate peak power. The lower fuel cost combined cycle plant will primarily provide off-peak power.

Table 37
Sensitivity of Economic NPVs to Peak Power Ratio

Peak Power Ratio	**Economic NPV - VRA - (million Cedis)**
15%	74,853
20%	99,003
25%	123,154
30%	*147,304*
35%	171,455
40%	195,605
45%	219,756

Real Fuel Costs

Fuel cost is among the main components of the overall cost of thermal power generation. Changes in the real cost of fuel have, therefore, an impact on the economic (as well as the financial from the utility viewpoint) return of a hydro plant. Table 38 shows that the economic NPV of the project is fairly sensitive to changes in the value of this variable. A 10 percent decrease in the real cost of fuel would lower the economic return of the project by about 31 billion Cedis (a change of -21 percent).

Table 38
Sensitivity of Economic NPVs to % Change in Average Real Fuel Cost

% Change in Real Fuel Cost	**Economic NPV - VRA - (million Cedis)**
-30%	55,283
-20%	85,957
-10%	116,630
0%	*147,304*
10%	177,978
20%	208,651
30%	239,325

Real Economic Value of Electricity

The real economic value of electricity avoided costs has been calculated to be equal to 107.5 Cedis (or 0.067 US$) per KWh. Given the prospect that Ghana might not be able to maintain sufficient thermal capacity to meet the demand if Bui is not built, shortages might arise. In such a situation, the average economic value of electricity might be increased considerably due to power shortages and outages. In Table 39 below the economic NPV of the project is calculated with the average economic value of electricity ranging between 100 and 152 Cedis/KWh (corresponding to a range from about 6 to 10 cents/KWh).

Table 39
Sensitivity of Economic NPVs to Economic Value of Electricity

Economic Value of Electricity (in Cedis/KWh)	**Economic NPV - VRA - (million Cedis)**
100	106,202
107.5	*147,304*
112	171,959
120	215,796
128	259,634
136	303,472
144	347,310
152	391,148

If Bui is being built in an environment where shortages arise, the increased value of the additional electricity supply will in turn substantially increase the economic value of the project.

11. Stakeholder Analysis

The stakeholder analysis of the Bui project is conducted to identify which particular segments of society reap the benefits and which ones, if any, lose from the implementation of the plant. The stakeholder analysis of any project builds on the following relationship:

$$P^e = P^f + \sum_{i=1} E_i \qquad (1)$$

where P^e is the economic value of an input or output, P^f is the financial value of the same variable and ΣE_i is the sum of all the externalities that make the economic value different from the financial value of the item.

In other words, the economic value of an item can be expressed as the sum of its financial price plus the value of externalities, such as taxes, tariffs, consumer/producer surplus. On the basis of identity (1), the following relationship also holds:

$$NPV^e_e = NPV^f_e + \Sigma PV_e\,(EXT_i) \qquad (2)$$

where NPV^e_e is the net present value of the net economic benefits at the economic discount rate, NPV^f_e is the net present value of the net cash flow at the economic discount rate, and $\Sigma PV_e\,(EXT_i)$ is the sum of the present value of all the externalities generated by the project.

In other words, all projects generate two types of net benefits: 1) financial net benefits, which accrue directly to those that have a financial interest in the project; and 2) distributive impacts or externalities, which are allocated to different segments of society. Relationship (2) holds for any discount rate, and in this case we use the economic discount rate.

As both the financial and economic evaluations of the Bui plant have been conducted from the VRA and the IPP perspectives, this study identifies the externalities of the plant in the scenarios where either the VRA or the IPP undertakes the analysis of the project. In each case, the stakeholder analysis requires the following steps:

1) identifying the stakeholder impacts of the project item by item by subtracting the financial cash flow statement from the economic statement of benefits and costs[25].

[25] As both the economic and financial analysis are conducted at the domestic price level, the stakeholder impacts of a project can be calculated as the difference between these two net resource flows.

2) calculating the present value of each line item's flow of distributive impacts, using the economic cost of capital (12.12%) as the discount rate.
3) allocating the present value of the externalities to the relevant groups in the economy.

Table 40
Distribution of Project Net benefits
- VRA implements the plant (alternative is thermal) -
(millions of 1997 Cedis)

	VRA	Government	Consumers	Labor
NPV Project (Utility viewpoint) @ financial d.r. (12%)	265,686			
NPV Project (Project viewpoint) @ financial d.r. (12%)	-90,344			
NPV Externalities @ economic d.r. (12.12%)		71,156	350,987	1,734

Table 41
Distribution of Project Net benefits
- an IPP implements the plant (alternative is thermal) -
(millions of 1997 Cedis)

	VRA	Government	Consumers	Labor
NPV Project (Utility viewpoint) @ financial d.r. (12%)	24,060			
NPV Project (Project viewpoint) @ financial d.r. (12%)	-331,970			
NPV Externalities @ economic d.r. (12.12%)		239,624	7,322	1,734

Tables 40 through 45 show the distribution of the total net benefits of the project, including both its financial values and its distributive impacts. Table 40 (as well as tables 42 and 43) shows that, if VRA undertakes the project, the government would realize a gain of about 71 billion Cedis (about 45 million US$). This is due in part (about 15 billion Cedis) to the gain in duties on imports of investment and operating cost items, net of the loss of foreign exchange premium. The most significant part (approximately 58 billion Cedis) is, however, the government savings of the foreign exchange premium that would have otherwise been lost on the imports for investment, operating and fuel costs of thermal power.

Table 40 shows that, because of the low current tariffs, the major beneficiaries of the project are the electricity consumers. The large difference between the average financial tariff charged by the project and the financial cost of thermal generation (assuming it measures the value of electricity to consumers) indicates that, with the project, customers receive a large consumer surplus. Also from Table 40, we see that consumers would be willing to pay for electricity 351 billion Cedis (approximately 219 million US$) more than what they are currently charged.

As shown in Table 44, if an IPP undertakes the Bui plant, the government would gain about 154 billion Cedis (about 96 million US$) in income taxes. On the other hand, in this scenario consumers would gain only 7 billion Cedis (about 5 million US$)[26].

The externality of 1.7 billion Cedis (about 1.1 million US$) accruing to Labor reflects the premium that VRA, belonging to the protected segment of the labor market in Ghana, pays on the market clearing wage.

[26] The externality of 7,322 million Cedis accruing to consumers in this scenario measures the portion of the overall externality corresponding to the very small difference between the financial cost of thermal generation (97.10 Cedis/Kwh) and the tariff charged by the IPP to VRA (95.79 Cedis/Kwh).

TABLE 42: ALLOCATION OF EXTERNALITIES - VRA implements the plant
(in million Cedis)

	PV externalities @ econ. d.r.	**Allocation of externalities** Government	Consumers	Labor	Total
ECONOMIC BENEFITS					
Economic benefit of replaced thermal power	409037	58050	350987		409037
Change in accounts receivable	-1698	-1698			-1698
Liquidation value -	0	0			0
Land	0				0
Dam & civil works	-16	-16			-16
Total Benefits	407323	56336	350987	0	407323
					0
ECONOMIC COSTS					0
Investment cost -					0
Land	0	0			0
Preparatory works		0			0
and construction facilities	-854	854			854
Civil works		0			0
Diversion	-361	361			361
Main dam	-6573	6573			6573
Saddle dam	-675	675			675
Power station	-988	988			988
Hydro-electromechanical equipment		0			0
Powerhouse equipment	4400	-4400			-4400
Water intake	27	-27			-27
Power intakes	725	-725			-725
Spillway	542	-542			-542
Administration & engineering	-8044	6737		1307	8044
Interconnection with the transmission grid		0			0
161 kv line	-2305	2305			2305
Substations equipment	144	-144			-144
Administr. & engineering	-704	495		210	704
Environmental impact					0
Reforestation	-395	395			395
Resettlement	-127	127			127
Infrastructure	-6	6			6
Operating costs -		0			0
Generation	-150	150			150
Transmission	-215	215			215
Distribution	-147	147			147
Administration	-797	579		218	797
Township	-69	69			69
Health & Safety	-54	54			54
Change in accounts payable	73	-73			-73
Change in cash balance	0	0			0
Total Costs	-16554	14820	0	1734	16554
NET ECONOMIC BENEFITS	423877	71156	350987	1734	423877

TABLE 43: DISTRIBUTION OF PROJECT EXTERNALITIES - VRA implements the Bui plant (in million Cedis)

	Government	*Consumers*	*Labor*
PV externalities @ economic d.r.	71156	350987	1734

RECONCILIATION OF ECONOMIC, FINANCIAL AND DISTRIBUTIVE ANALYSIS

NPV financial @ economic d.r.	-276573
PV externalities @ economic d.r.	423877
NPV economic @ economic d.r.	147304

NPV econ. @ econ. d.r = NPV financial @ econ. d.r. + PV externalities @ econ. d.r.

147304 = -276573 + 423877

147304 = 147304

TABLE 44: ALLOCATION OF EXTERNALITIES - an IPP implements the Bui plant
(in million Cedis)

	PV externalities @ econ. d.r.		**Allocation of externalities** Government	Consumers	Labor	Total
ECONOMIC BENEFITS						
Economic benefit of replaced thermal power	65372		58050	7322		65372
Change in accounts receivable	14743		14743			14743
Liquidation value -						0
Land	0					0
Dam & civil works	-16		-16			-16
Total Benefits	80099		72778	7322	0	80099
ECONOMIC COSTS						
Investment cost -						
Land	0		0			0
Preparatory works			0			0
and construction facilities	-854		854			854
Civil works	0		0			0
Diversion	-361		361			361
Main dam	-6573		6573			6573
Saddle dam	-675		675			675
Power station	-988		988			988
Hydro-electromechanical equipment						0
Powerhouse equipment	6031		-6031			-6031
Water intake	27		-27			-27
Power intakes	725		-725			-725
Spillway	542		-542			-542
Administration & engineering	-8044		6737		1307	8044
Interconnection with the transmission grid						
161 kv line	-2305		2305			2305
Substations equipment	144		-144			-144
Administr. & engineering	-704		495		210	704
Environmental impact	0		0			0
Reforestation	-395		395			395
Resettlement	-127		127			127
Infrastructure	-6		6			6
Operating costs -	0		0			0
Generation	-150		150			150
Transmission	-215		215			215
Distribution	-147		147			147
Administration	-797		579		218	797
Township	-69		69			69
Health & Safety	-54		54			54
Income tax liability	-153657		153657			153657
Change in accounts payable	73		-73			-73
Change in cash balance	0		0			0
Total Costs	-168580	0	166846	0	1734	168580
NET ECONOMIC BENEFITS	248680	0	239624	7322	1734	248680

TABLE 45
DISTRIBUTION OF PROJECT EXTERNALITIES - an IPP implements the Bui plant
(in million Cedis)

	Government	*Consumers*	*Labor*
PV externalities @ economic d.r.	239624	7322	1734

RECONCILIATION OF ECONOMIC, FINANCIAL AND DISTRIBUTIVE ANALYSIS

NPV financial @ economic d.r.	-101376
PV externalities @ economic d.r.	248680
NPV economic @ economic d.r.	147304

NPV econ. @ econ. d.r = NPV financial @ econ. d.r. + PV externalities @ econ. d.r.

147304 = -101376 + 248680

147304 = 147304

Conclusions

This study shows how the results of the appraisal of a power project differ when the analysis is undertaken from different perspectives.

From the utility perspective, Bui is a sound project because the alternative to Bui is a set of thermal plants, which are more costly to build and operate. The project perspective is highly relevant to the IPP, which must at least recover its financial opportunity cost in order to be willing to undertake the project.

In many countries, the price of electricity is well below the marginal cost of supplying electricity to the different groups of customers. In this case we consider the change in tariffs needed to cover the average costs of this new generation plant. The required change to the tariffs is different when the utility or an independent power producer owns the project. In the current study, we found that if VRA owns Bui, an increase of about 7% in the domestic tariff structure is sufficient for the utility to financially break even because the utility has access to subsidized financing. On the other hand, a 24% increase in tariff is required when an independent power producer sponsors the Bui project, and is not able to use subsidized financing.

The stakeholder analysis gives insights on the distributional impacts of the project on government and consumers. The extent to which each of them is affected by the project depends upon the mechanism put in place to pay for the power project. Without the low cost financing available through the government, the financial burden borne by consumers is higher when an IPP undertakes the project. When evaluating power projects where private provisions are envisaged, the benefits of such provisions must be weighted against the social costs inherent with such private operations.

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