REGIDESO – Régie de production et de distribution d'eau et d'électricité

Financial Assessment of Electricity Operations 2010 - 2025

Draft Report

Submitted to the World Bank

Submitted by:

Gulam Dhalla, Financial Consultant

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1 Introduction

1.1 This report is submitted by Gulam Dhalla, Independent Financial Consultant, engaged by the World Bank to undertake a financial assessment of the electricity operations of REGIDESO (Régie de Production et de Distribution d'Eau et d'Electricité), the national power utility of Burundi. The assignment calls for the review of the current and planned electricity supply and demand balance and a comprehensive financial analysis and revenue forecast required to meet the demand supply balance in the medium term to 2025. The main objective of the consultancy services is to analyse the tariff implications of REGIDESO's electricity generation expansion plans to 2025as derived from the aggregated revenues and costs of supply.

1.2 The terms of reference for the assignment are provided below:

- Review and update all relevant parameters and assumptions in the financial model.
- Allocate all operational costs, assets and liabilities, including common services, between electricity and water operations.
- Review the electricity supply demand up to 2025 (prepared under a separate assignment) and associated generation sources with the aim at integrating T&D costs and associated recurrent costs.
- Integrate the demand forecasts to 2025 prepared under a separate assignment.
- Review and evaluate the recent past and present operational and financial performance.
- Integrate the investment plan to 2025 and propose financing plan, including financing terms for each project.
- Prepare financial projections to 2025.
- After the above diagnostic analysis on the financial costs and fiscal impacts on REGIDESO, recommend any necessary regulatory and policy drivers which are key to the financial success of the electricity operations -- e.g. adjusting tariffs taking into account the recommendations of the recent Tariff Study, changing tariff structure for lifeline rates, adjusting Government financial contribution towards investments and operational costs, etc.
- Evaluate the impacts on utility's financial viability in view of the proposed investments and ongoing commitments.
- The financial model will also revise the recent Tariff Study to propose cost reflective average electricity tariff and calculate the amount of government subsidy likely to be required between now and 2025 if prices remain the same and indicate possible paths for the increase of the average tariff.
- Suggest some necessary sensitivity analysis, based on critical parameters identified as part of the analysis.

2 Background

2.1 Thepower sector in Burundi comprises the Ministry of Energy and Mines (MEM), REGIDESO (Régie de Production et de Distribution d'Eau et d'Electricité) and ABER (Agence Burundaise de l'ElectrificationRurales). MEM is responsible for policy making. REGIDESO has autonomous legal and financial status and operates under the supervision of MEM. It is a vertically integrated utility responsible for electricity generation, transmission and distribution and for water services. REGIDESO had 75,847 customers in 2012 who are mainly located in urban areas.

2.2 Burundi's installed generation capacity is about 53 MW (including its share of Ruzizi I and II and excluding 10 MW emergency generation contracted by the Government of Burundi (GoB) in March 2013). Most of the country's electricity supply is generated by REGIDESO through seven hydro plants, which have a combined installed power capacity of 31.5 MW.

2.3 The World Bank intends to cofinance additional generation at the Jiji and Mulembwe run of river sites that will be owned and operated by REGIDESO. The Jiji and Mulembwe hydropower development includes the construction of the Jiji power scheme with an installed capacity of 31.5 MW, the Mulembwe power scheme with an installed capacity of 16.5 MW and the connection to the Bujumbura South substation via an 80 km 110 kV transmission line. The nearby main consumption centre of the south, Bururi, will be connected to the project by a 30 kV line. The two plants will be located 3.75 km from each other, but not in a cascade (the Mulembwe river is a tributary to the Jiji river, downstream of the Jiji power plant).

2.4 In this context the World Bank has initiated this study. The financial analysis is to assess whether the project is financially viable for REGIDESO. Based on the capital costs, financing conditions (IDA conditions in the range 2.0 percent, with repayment of principal over 20 years and 5 years grace period), operations and maintenance costs, energy output, the financial analysis will be based on (i) the annual revenue requirements and the tariff needed for the viability of REGIDESO over a 40 year lifetime; and (ii) the financial benefits to REGIDESO of doing the project rather than running thermal generators.

3 Executive Summary

REGIDESO Combined Operations – Recent Performance

3.1 The overall financial performance of REGIDESO (combined water and electricity operations) has progressively improved since 2011 following increases in water and electricity tariffs in September 2011 and March 2012. Water and electricity tariffs were previously revised in May 2007. Prior to the last two tariff increases, the utility's financial performance and its financial position was weak. Financial restructuring of REGIDESO's balance sheet as at December 31, 2008 was undertaken to clear or write-off overdue accounts of the Government, unpaid import bills of SNEL and SINELAC and loans related to investments financed by donors. Import bills of SNEL and SINELEC up to 2007 were settled by GoB and nothing was paid between 2008 and 2010. REGIDESO started paying for its import bills from January 2011onwards and the overdue bills of SNEL were cleared by September 2012 and the SINELAC debt is expected to be cleared by end 2013.

3.2 REGIDESO as a whole made a net profit after tax of FBU3,522 million[1] (US$2.4 million) in 2012 compared with net losses of FBU547 (US$0.4 million) and FBU767 million (US$0.6 million) in 2011 and 2010 respectively. REGIDESO's combined water and electricity operations generated net cash inflows of FBU2,754 million (US$1.9 million) in 2012 and FBU3,005 million (US$2.3 million) in 2011 and net cash outflow of FBU586 million (US$0.5 million) in 2010. The financial results take account of the World Bank subsidies towards fuel costs for thermal power generation of FBU869 million (US$0.6 million) in 2012, FBU6,679 (US$5.1 million) in 2011 and FBU4,298 (US$3.5 million) in 2010.

3.3 REGIDESO's combined water and electricity operations generated net cash inflows of FBU2,754 million (US$1.9 million) in 2012 and FBU3,005 million (US$2.3 million) in 2011 and net cash outflow of FBU586 million (US$0.5 million) in 2010; all after receipt of electricity generation fuel subsidies. Without such subsidies, the utility would have generated net cash inflows of FBU1,885 million (US$1.3 million) in 2012 and net cash outflows of FBU 3,674 million (US$2.8 million) in 2011 and FBU4,884 million (US$4.0 million) in 2010.

3.4 The financial position of REGIDESO has improved over the past three years. Based on the utility's financial statements, the current ratio has improved to 3.5 times as at December 31, 2012 (2.6 times at end 2011) and the debt/equity ratio at the last two balance sheet dates were low and ranged between 13% and 11%.However, it should be noted that accounts receivable, as reported in the financial statements, are most probably overstated as they are unlikely to be collected in full.

Combined Operations – Key Issues & Recommendations

3.5 **Finance Department:** The reporting of operational and financial performance within REGIDESO is not satisfactory. Conflicting data between technical, commercial and financial departments makes it difficult to

[1] Unaudited results

undertake analysis of REGIDESO's performance with a reasonable degree of confidence. The accounting systems are antiquated and there is an urgent need for the installation of a new computerized accounting system that is integrated with other software applications such as commercial and inventory systems. Accounting staff require training and coordination within the finance department and across REGIDESO need to be strengthened.

3.6 The following recommendations are made so as to strengthen the finance function in REGIDESO and to improve internal controls.

i) Appoint a qualified, experienced accountant to head the finance department for a limited period of two years. Ideally, the appointee should be (a) an expatriate who is devoid of local politics, and (b) fluent in both French and English. The appointee should be someone who is willing to "dirty" his/her hands and work closely with REGIDESO staff. The tasks of the appointee should include:

(a) Reorganization of the finance department with the objectives of improving its functions and coordination within and across departments.
(b) Introduction of a new computerized accounting system that meets the present day needs of the utility, including linkages with the billing system.
(c) Training of finance staff, both internal and external.
(d) Quarterly reporting of financial performance.

ii) Review and revise salary scales of key finance staff to match those of the private sector. REGIDESO is currently experiencing difficulties in retaining capable staff in the finance department.

iii) The procurement function should be separated out the finance department and established as a separate department. This is necessary to improve internal control.

3.7 Audited financial statements should be issued in a timely manner (within six months of the year-end). Issuance of the audited accounts should not be delayed on account of audit qualifications. The audit for REGIDESO's 2012 financial statements has not yet been completed.

3.8 **Commercial Department:** The recording of billing collection and customer accounts in REGIDESO's billing system for both water and electricity operations are combined and it therefore makes it difficult to separate the underlying collection performance and customer accounts between the two operations. The present billing system is antiquated(introduced in 1992) and the system is also unreliable and the monthly billing statistics are erratic. Conflicting data generated by the existing system makes it difficult to assess the accuracy of reported data. For example, the billing statistics reported in REGIDESO's annual report for 2012 indicates that overall network losses reached 24%; on the other hand, the technical audit (RAPPORT FINAL for 2011 and 2012, dated June 30, 2013, submitted by Jacque Corbin, Expert Comptable) indicates that the losses amounted to 20.3% (including auxiliary losses). In addition, the auditors of REGIDESO have always expressed many reservations about the reliability of commercial data. The reporting of commercial data is therefore not satisfactory and there is an urgent need to replace the existing billing software. The billing for water and electricity should be separated.

3.9 The accounts receivable in the billing system have accumulated over the years and a large part of the recorded debt is not collectable. It is recommended that the records of the commercial departments are reviewed and old irrecoverable balances are cleared from the records.

Electricity Operations – Key Issues & Recommendations

3.10 **Kagunuzi Hydro IPP &Emergency Thermal:** REGIDESO's generation expansion plan envisages the procurement of electricity from a private developer and operator (IPP) of a hydro power plant with an installed capacity of 8MW and an estimated annual energy output of between 44GWh to 50GWh. The developer's proposals include the transfer of ownership to REGIDESO after 25 years and an indicative tariff of 0.226US$/kWh in Years 1 to 25. Capital investment costs of the plant are estimated at US$52 million (including interest during construction) and equivalent to US$6,500/MW installed. The indicative tariff of 0.226US$/kWh is considered to be expensive and it is not the least cost option. The contract will place a significant financial burden on REGIDESO for the next 25 years. This will be take or pay contract and REGIDESO will be obliged to pay the monthly fixed costs as long as the declared capacity is available. The power purchase costs for this plant are estimated to amount to around US$10.7 million each year and US$371 million over 25 years. It is recommended that the Government should not enter into this contract under the terms proposed by the developer. The Government should not consider this project in the context of shortages in power supply over the next few years, it is more important to take a long term view and consider the financial implications over the long term. It would be better to extend the term of the existing 10MW rental thermal to cover the supply deficits beyond April 2015 when the existing contract expires. Two alternative scenarios have been considered and the financial impacts of these scenarios are shown in Table 28 further below. The results indicate that it is financially more prudent to rely on the more expensive thermal power in the short term than to commit to a long term hydro supply contract that will involve in high fixed costs. The financial impact under Scenario I (without Kagunuzi and rental thermal contract not extended) is estimated to result in net additional revenues of US$92.2 million, equivalent to 22.2% of projected electricity revenues based on December 2012 tariffs. The financial impact under Scenario II (without Kagunuzi and rental thermal contract extended by two years to April 2017) is estimated to result in net additional revenues of US$76.7 million, equivalent to 18.5% of projected electricity revenues based on December 2012 tariffs. Scenario II is the recommended option as the additional capacity during the two years to April 2017 will be needed to meet the underlying domestic demand.

3.11 **Network Losses:** Overall transmission and distribution (T&D) losses averaged 19.5% over the past three years. The losses in 2012 reached 19.9% as per REGIDESO's technical auditor; however, REGIDESO's annual report for 2012 states that the losses were in the region of 24%. The variations in reported losses are due to the unreliability of REGIDESO's billing system. The average losses over the previous four years (2008 to 2011) were 19.7%. It is estimated that about 40% of overall losses can be attributed to technical losses. Metering is considered to be good; although at times meters get locked when power voltage is low and electricity consumption goes unrecorded (approximately 2-3% of losses can be attributed to this). The distribution network needs to be rehabilitated and strengthened. Revenue lost and uncollected for every 1% of T&D losses is estimated at FBU349 million (US$0.226 million), based on the estimated present tariffs and the average collection rate of 84.1%.Assuming optimum network losses of 13.2% and billing collection rate of 97.5%, FBUX 2.75billion (US$1.8 million) can be recovered annually through efficiency gains. This is the level of the challenge facing both REGIDESO and the Government. REGIDESO should exert all efforts to bring down the network losses and increase billing collection. The base case analysis assumes that distribution losses are reduced by 0.25% each year.If the assumed reductions in distribution losses each year of 0.25% over the next twelve years are achieved, and based on the projected average tariffs, there will be a positive cash flow impact of US$10 million to 2025.

3.12 **Billing Collection:** The billing collection rate has varied considerably over recent years. The average collection rate in 2012 has worsened considerably and it is not clear if this reflects the true underlying performance or whether the figures are distorted due to the inaccuracies of the statistics generated by an unreliable billing system. The overall billing collection rates(based on current year billing) for both water and electricity over the past four years are indicated in the following table.

	2010	2011	2012	Average
As per financial statements data	90.7%	88.3%	73.1%	84.1%
As per technical audit	92.1%	82.3%	76.0%	83.5%

Table 1: Billing Collection Rates 2010-2012 - Water & Electricity Combined

3.13 The deterioration in the billing collection performance over the past three years is a cause for concern. The performance should be improving, especially since the proportion of electricity prepayment billing has doubled to 32.4% since 2010. The large increases in both water and electricity tariffs in September 2011 and March 2012 (cumulatively 140% for water and 70% for electricity) may have contributed to the decline in the collection performance. REGIDESO should exert all possible efforts in improving its billing collections. If the assumed improvements in the overall Burundi billing collection rate of 1.5% each year (increasing from the present 84% to 96% by 2025), and based on the projected average tariffs and network losses, there will be a positive cash flow impact of US$56 million to 2025.

3.14 **Electricity Tariffs:** Present tariffs will be inadequate to meet REGIDESO's projected revenue requirements over the next few years. A combination of GoB support/subsidies towards thermal costs and upward revisions in tariffs will be required to cover the revenue shortfalls. The challenge is to establish cost reflective tariffs and at the same time protect the low income household customers with low consumption.

3.15 The recommended financing plan to meet the projected revenue shortfalls over the next thirteen years to 2025 involves (a) GoB subsidy to cover the full capacity and fuel costs of the rental thermal and 75% fuel costs of the Bujumbura thermal plant from 2014 to 2016, and (b) average tariff increases of 30% on January 1, 2016 and 25% on January 2017. Tariffs could be gradually reduced from 2018 to 2020 as low cost hydros come on line. Full details of the revenue requirements and the recommended financing plan are provided in Table 26 below.

3.16 **Generation Expansion& Electricity Access:**

3.17 The Government has set ambitious plans to expand the installed generation capacity. The base case analysis presented in this report assumes that the capacity will increase from the existing 68.4MW (including 10MW rental thermal expiring in 2015) to 250MW and increase access to electricity from the present 4.5% to 15.6% by 2025. The challenge of the base case scenario is to (a) attract the needed public/private investments (estimated at US$570 million for generation) as the Government's capacity to provide financing is limited, (b) gradually build-up capacity over time to meet the underlying domestic demand (i.e. avoid idle capacity), (c) recover annual fixed costs (recovery of investment, financing costs, returns on equity and fixed operations and maintenance costs) from electricity customers, and (d) secure Government guarantees (estimated at US$287 million from 2013 to 2025, refer to paragraph 6.78 and Table 41 below) that investors will require as security for the recovery of their fixed capacity charges over the term of their power purchase agreements.

3.18 TheGovernment'svision to 2025 envisages that 25% of the country's population will have access to electricity. The Government's target to 2025 is considered to be optimistic as it will require 572,000 new connections over twelve years between 2014 and 2025 (i.e. annual average connections of 47,667) and involving investments of US$277 million approximately.

3.19 The base case analysis presented in this report assumes an electrification program that will involve 326,000 new connections from 2014 to 2025. The electrification program, as assumed in this analysis, is accelerated over the years, starting from 8,000 new connections in 2014 and reaching 53,000 in 2025. Recent history shows that REGIDESO connected 6,713 new customers in 2011 and 9,307 in 2012 (the World Bank financed a large part of the needed investments). REGIDESO plans to connect 7,636 new customers in 2013. The projected new connections program will require investments of US$158 million approximately and access rate is forecast to reach 15.6% by 2025 (refer to Table 20 below).

3.20 The adopted base case demand scenario is probably optimistic and it will be a challenge for REGIDESO to secure financing and implement the electrification program and generation expansion that this will entail. The financial implications of other demand growth scenarios have been considered in the sensitivity analysis presented further below in paragraph 6.75.

3.21 **Surplus Capacity and Exports:** Based on the base case generation expansion plan, REGIDESO will have capacity that is surplus to domestic requirements. The surplus will progressively increase over the years as the projected new capacity is added. The need to export such surpluses is critical to the financial viability of REGIDESO if the planned generation expansion is implemented. Net cash inflows arising from “new” exports, as assumed in the base case analysis, account for FBU872 billion (US$415 million) in export revenues, equivalent to 84% of Burundi electricity revenue forecast over the eight years from 2018 to 2025.However, there is a potential risk for Burundi in that the neighbouring countries also have ambitious generation expansion plans and there is a possibility of available power supply in the region exceeding demand.

3.22 **Generation Expansion (domestic resources vs. imports):** Generation expansion planning beyond 2020 should incorporate the potential opportunity to import cheaper hydro based power from Ethiopia and DRC. Such imports could bring considerable financial benefits to the Burundi economy if the cost of power (generation plus wheeling) is cheaper than the domestic generation that it displaces. The Government and REGIDESO should initiate discussions with Ethiopia to secure the projected capacity needs of Burundi in the future.

Electricity Operations – Recent Performance

3.23 Peak demand in Burundi grew at an annual average rate of 4.46%, rising from 45.5MW in 2009 to 54.0MW in 2012. Electricity sent out during the same period has grown from 207GWh in 2009 to 243GWh in 2010. As a percentage of total supply, hydro output from REGIDESO’s plants accounted for 56.1% in 2012 (52% in 2011), hydro imports accounted for 42.7% in 2012 and 2011 and the balance of requirements was met from the Bujumbura thermal plant (1.2% in 2012 and 5.3% in 2011). The use of the Bujumbura thermal plant was restricted due to financial constraints.

3.24 Overall transmission and distribution (T&D) losses averaged 19.5% over the past three years (19.9% in 2012).Revenue lost and uncollected for every 1% of T&D losses is estimated at FBU349 million (US$0.226 million), based on the estimated present tariffs and the average collection rate of 84.1%.

3.25 Electricity billed to end-use customers registered growth rates of 14.1% and 5.4% in 2010 and 2011 and declined by 2.3% in 2012, reaching 194.8GWh in 2012. Growth in recent years was limited due to capacity constraints.

3.26 The ratio of the average number of customers per employee has improved significantly over recent years, rising from 73 in 2009 to 101 in 2012. However, the latest ratio does not compare well with the regional utilities (refer to Section 7 below).

3.27 Total number of electricity customers billed increased by 38% since December 2009 to reach 75,847 by December 31, 2012. New customers connected reached 9,307 in 2012, 6,713 in 2011 and 4,797 in 2010. As at December 31, 2012, customers were connected with prepayment meters accounted for 43% of total customers and 64% of customers were in Bujumbura.Customers with prepayment meters accounted for 31.3% of total electricity sales and 32.5% of total electricity revenue in 2012.

3.28 Thefinancial performance of REGIDESO’s electricity operations improved significantly in 2012 following the large tariff increases in September 2011 and March 2012. The full impact of the tariff adjustments will be felt in 2013. The financial performance was helped by the fact that thermal output in 2012 was considerably lower than in the previous two years.

3.29 REGIDESO’s electricity operations made net profits of FBU3,761million (US$ 2.6 million) in 2012 and FBU2,775 (US$ 2.1 million) in 2011. The profits are inclusive of WB’s fuel subsidies of FBU869 million (US$ 0.6 million) in 2012 and FBU6,679 million (US$ 5.1 million) in 2011. In its 2012 income statements, REGIDESO recorded provisions for bad debts of FBU4,679 million (US$3.2 million), with minimal provisions in earlier years despite the fact that overall billing collection rates were far below 100%. REGIDESO will have to make significant provisions in its 2013 financial statements so as to reflect a true and fair value of accounts receivable. A provision for bad debts of approximately FBU11.1 billion (US$7.2 million)relating to accumulated uncollected billings to end 2012. The financial performance on a comparable basis excluding fuel subsidies and provisions for bad debts would have produced net profits of FBU7,571 million (US$5.2 million) in 2012 and net losses of FBU3,751 million (US$2.9 million) and FBU788 million (US$0.6 million) in 2011 and 2010 respectively.

3.30 Electricity tariffs[2] were revised effective September 1, 2011 and March 1, 2012. The energy tariff for the domestic first block (0-50/kWh per month) was reduced by 6.8% effective June 1, 2012. Electricity tariffs were previously revised on May 1, 2007. The impact of the tariff increases in September 2011 and March 2012 were estimated to increase REGIDESO's weighted average electricity revenue by 70.3% (140% for water). The actual cumulative increase in the weighted average electricity tariff to June 1, 2012 is estimated at 69%.

3.31 The actual weighted average electricity revenue increased from 101FBU/kWh (0.082US$/kWh) in 2010 to 110FBU/kWh (0.085US$/kWh) in 2011 and 148FBU/kWh (0.102US$/kWh) in 2012. The present weighted average revenue is estimated at 171FBU/kWh (0.107US$/kWh). In terms of the local currency, the average revenue increased by 8.7% in 2011 and by 34.9% in 2012. In US dollar terms, the average revenue increased by 3.2% in 2010 and 10.4% in 2012.

3.32 The weighted average electricity revenue in 2012 of148FBU/kWh (0.102US$/kWh), compared with the cost of service (CoS), excluding fuel subsidies, of 133FBU/kWh (0.092US$/kWh), giving a profit margin of 10%. On the basis of cash flow requirements, the average revenue requirements in 2012 amounted to 149FBU/kWh (0.102US$/kWh), almost equal to the average revenue.

3.33 REGIDESO's electricity operations generated net cash inflows of US$0.8 million and US$1.8 million in 2012 and 2011, compared with net cash outflows of US$0.3 million in 2010. Capital investments in the past three years amounted to US$40.6 million, largely funded through GoB and donor grants and customer contributions and deposits. Debt service payments were minimal.

3.34 REGIDESO had healthy current ratios in recent years as per its financial statements. However, current assets reflect receivables from customers which may not be fully recoverable. The current ratio as at December 31, 2012 would drop by 1.0 to 2.2 times if accounts receivable were stated in the balance sheet at fair value. REGIDESO has no debt and GoB/donor grants for investments have managed to keep the debt/equity ratios low.

Electricity Operations - Future Outlook to 2025

3.35 REGIDESO's financial prospects for its electricity operations over the next thirteen years to 2020 will be largely dictated by the following: (a) demand growth and sources and costs of power supply, (b) capital investments and financing thereof, (c) electricity tariffs, (d) operating costs, (e) efficiency improvements in network losses, billing collection and operating costs, (f) Government support or subsidies towards thermal costs, and (g) borrowing terms for new debt secured for investments.

3.36 The base case analysis to 2025 as presented in this report assumes that electricity demand in Burundi will grow as per the base case demand growth forecast undertaken in August 2013 by Mr Ananda Covindassamy, Consultant to the World Bank. In view of capacity constraints, the underlying electricity demand up to 2015 will not be fully met. On this basis, demand is expected to grow by 5.2% and 4.9% in 2013 and 2014 respectively, and decline by 5.0% in 2015. The projected capacity additions in 2015/16 will lead to high demand growth of 20.1% in 2016 and 25.9% in 2017. Thereafter, the annual demand growth is forecast to range between 10.3% and 12.3%.

[2] References to electricity tariffs in this report are exclusive of 18% Value Added Tax (VAT) added to customer bills

3.37 Peak demand and energy sent out in Burundi is projected to grow from 54MW and 243GWh in 2013 to 204MW and 925GWh by 2025.Available energy supply based on the generation expansion plan detailed further below is allocated to meet Burundi demand and any remaining surplus energy is assumed to be exported (firm and non-firm power). Based on the base case assumptions, surplus energy can be exported (ranging from 120GWh in 2018 to 600GWh in 2020 and decreasing thereafter to reach 244GWh in 2025 (refer to Table 18 below).

3.38 Transmission losses are assumed to remain constant throughout the forecast period (estimated at 5%). Distribution losses, as a percentage of bulk supply, are forecast to decrease from the assumed present level of 15.7% by 0.25% each year starting 2014. On this basis, the overall transmission and distribution losses for Burundi supply are expected decline from the present 19.9% to 17.1% by 2025.The following chart illustrates the forecast energy sent out, sales and overall T&D losses.

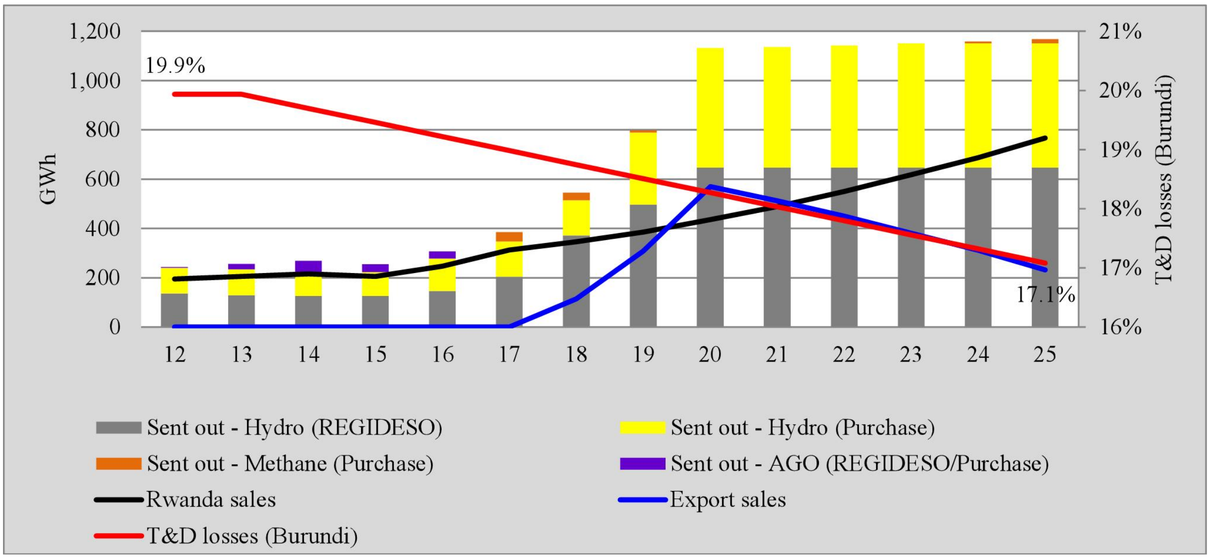

Chart 1: Forecast Energy Sent Out, Sales & T&D Losses 2013 to 2025

3.39 REGIDESO's investment requirements in generation expansion, the extension, reinforcement and rehabilitation of the transmission and distribution networks over the next thirteen years to 2025 are considerable and the levels of investments undertaken will largely depend on the availability of funding from donors, REGIDESO and GoB. REGIDESO's capacity to provide funding out of internal resources will be determined by the levels of electricity tariffs, collected revenues, customer contributions to new connections, and revenue requirements. The projected total investment requirements over the next thirteen years to 2025 are estimated at US$867 million (excluding generation investments to be undertaken by IPPs), equivalent to annual average investments of US$67 million. The projected financing plan for such investments will require 27% funding (US$235 million) from internal resources, 7% funding (US$57 million) from customer contributions, 42% funding (US$366 million) through borrowing (on-lent GoB/donor funds) and the remaining 24% funding (US$209 million) from Government and donor grants. A large part of proposed borrowing and grants is under negotiation or unsecured. Increasing depreciation allowances in the tariff will enable REGIDESO to finance a larger proportion of investments in the future. The make-up of investments considered in the base case projections is detailed in Table 24 below.

3.40 REGIDESO's forecast revenue requirements over the next threeto four years will remain high as long as long it has to rely on thermal power supply to 2016 and the expensive hydro supply from the proposed Kagunuzi IPP which comes on line in 2016. This situation is forecast to continue through to 2017 before cheaper donor funded hydro plants (Jiji, KABU 16 and Mulembwe) come on line from late 2017 to 2019. The forecast revenue requirements to 2025 will not be met through present electricity tariffs. The level of Government support in meeting future electricity revenue requirements is matter of Government policy; it is a trade-off between (a) subsidies to electricity consumers, who are generally the better-offs in society, and (b) support to other sectors, such as health, education, social welfare, etc that benefits the wider population. The important element of electricity pricing is to ensure that life-line electricity consumers are protected at all times. The life-line monthly consumption band was progressively reduced from 150kWh to 100kWh in September 2011 and to 50kWh in March 2012. The present life-line monthly consumption band in Uganda is 0-15kWh and 0-50kWh in Kenya and Tanzania.

3.41 REGIDESO's base case forecast <u>annual</u> revenue requirements are expected to increase from FBU16.3 billion (US$11.2 million) in 2012 to FBU44.3 billion (US$27.7 million) in 2013, FBU55.4 billion (US$32.8 million) in 2014 and FBU44.0 billion (US$25.1 million) in 2015 (the drop in 2015 is due to the retirement of the rental thermal in April 2015). Revenue requirements in 2016 and 2017 are expected to increase to FBU58.8 billion (US$32.4 million) and FBU70.7 billion (US$37.7 million) respectively (largely due to "new" power purchase costs relating to Kagunuzi hydro IPP and Lake Kivu methane based supply from EWSA). In the subsequent three years, the revenue requirements are forecast to reach FBU119.4 billion (US$62.0 million) in 2018 (increase largely due to new debt service requirements), FBU162.8 billion (US$82.3 million) in 2019 (increase largely due to "new" supply from Rusumo hydro and investments to be funded from internal resources), FBU220.3 billion (US$108.8 million) in 2020 (increase largely due to "new" supply rom Ruzizi III hydro higher). The annual requirements in the subsequent five years are expected to increase gradually from FBU242.5 billion (US$226.4 million) in 2021 to FBU321.8 billion (US$142.1 million) by 2025.

3.42 The base case forecast revenue requirements, electricity revenues (based on present tariffs) and revenue surpluses/shortfalls of REGIDESO's electricity operations, together with a proposed financing plan to meet the projected revenue shortfalls from 2013 to 2025 are summarized in Table 24below. The funding shortfalls over the next thirteen years are estimated to amount to FBU373 billion (US$181 million), equivalent to 17% of the total revenue requirements. A combination of tariff and non-tariff measures will be needed to close the financing gap. Government support towards thermal costs will not be required from 2017 onwards and there will be scope to reduce electricity tariffs in 2018 to 2020. The proposed financing plan envisages the following revenue raising measures:

i) <u>Government tariff support</u>: IDA support towards fuel costs of thermal power generation in 2013 is estimated to contribute FBU4.9 billion (US$3.06 million). In addition to this support, the base case analysis assumes that the Government will finance in full the remaining thermal costs relating to the rental thermal and 75% of fuel costs of REGIDESO's Bujumbura thermal plant in 2013 to 2016, amounting in total to FBU5.0 billion (US$3.1 million) in 2013, FBU25.0 billion (US$14.8 million) in 2014, FBU13.5 billion (US$7.7 million) in 2015, and FBU11.2 billion (US$ 6.2 million) in 2016. These direct subsidies have been introduced so as to moderate the tariff increases proposed below. The projected GoB support (including IDA) is equivalent to 22.4% (in 2013), 45.1% (in 2014), 30.6% (in 2015), and 19.0% (in 2016) of the total revenue requirements in each of those years. These figures show that GoB support is crucial over the next four years, and without such support, the needed tariffs would have to be raised to levels that will be unsustainable.

ii) <u>Electricity tariffs</u>: After taking account of GoB support (as indicated above), the base case financial analysis assumes that electricity tariffs will be increased over the coming years, as indicated in the following table.Additional collected revenues raised through such tariff increases are estimated to raise FBU11.2 billion (US$6.2 million) in 2016, FBU30.0 billion (US$16.0 million) in 2017, and FBU29.4 billion (US$15.2 million) in 2018. In the subsequent three years to 2021, the additional collected revenues will be considerably lower in view of the projected tariff decreases in these three years. Tariff increases in the following four years to 2025 will provide additional collected revenues. The financial impact of the projected tariff adjustments over the entire forecast period from 2013 to 2025 is estimated to add FBU349 billion (US$162 million), and accounting for 16% of the revenue requirements over the entire forecast period. The following table and chart show the base case projected levels of the weighted average retail electricity tariff to 2025.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Forecast												
Date of tariff increase	March & June 12	Jan 13	Jan 14	Jan 15	Jan 16	Jan 17	Jan 18	Jan 19	Jan 20	Jan 21	Jan 22	Jan 23	Jan 24	Jan 25
Average tariff increase	35%	0%	0%	0%	30%	25%	-5%	-27%	-10%	0%	28%	14%	13%	12%
Cumulative tariff increase post June 2012	35%	0%	0%	0%	30%	63%	54%	13%	1%	1%	30%	48%	67%	87%
Weighted average tariff at date of tariff adjustment														
FBU/kWh in nominal prices	171	171	171	171	222	277	263	192	173	173	221	252	285	319
US$/kWh in nominal prices	0.110	0.103	0.099	0.095	0.120	0.146	0.135	0.096	0.084	0.082	0.103	0.115	0.127	0.140
FBU/kWh in 2012 prices	171	156	148	140	172	205	185	129	110	105	128	139	150	160
US$/kWh in 2012 prices	0.110	0.101	0.096	0.090	0.111	0.133	0.120	0.083	0.071	0.068	0.083	0.090	0.097	0.103

Table 2: Projected Retail Electricity Tariff Path 2012 to 2025

3.43 Alternative tariff scenarios for the next few years to 2017 and their impact on Government tariff support are detailed in Table 26 below.

3.44 The following chart showsthe projected cost of service,operating revenues and revenue surpluses/shortfalls over the forecast period. Electricity revenues are forecast on the basis of projected demand and tariffs. Totaloperating revenues are inclusive of GoB subsidies and the operating surpluses/shortfalls are after taking account of these subsidies.

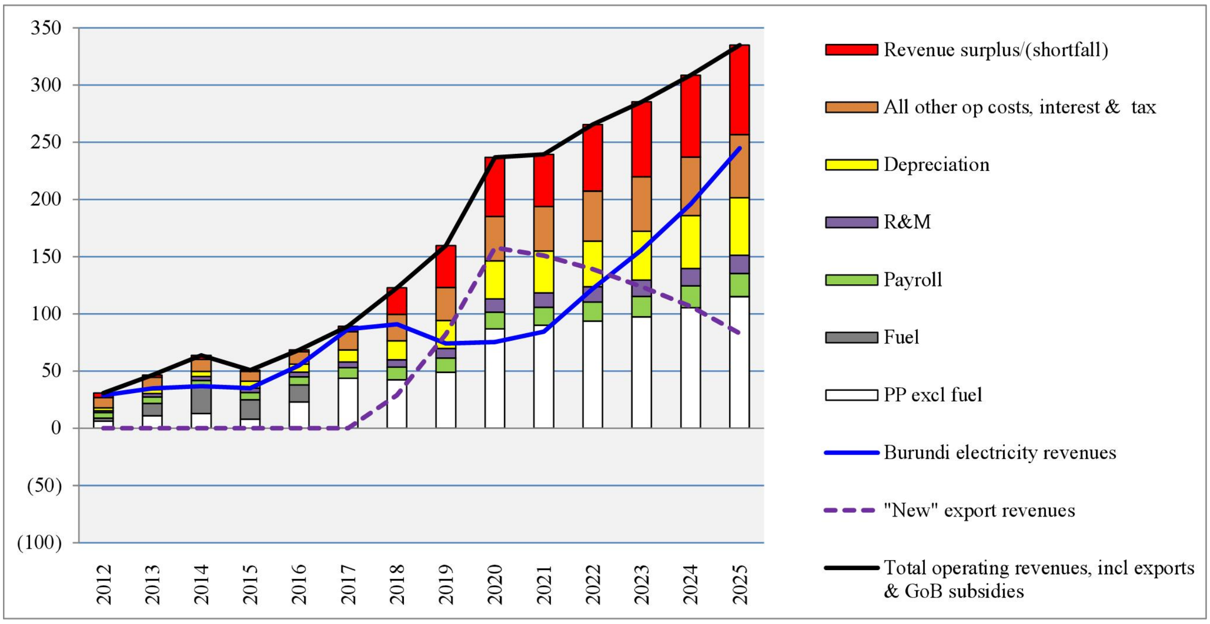

Chart 2: Electricity Cost of Service vs. Operating Revenues, including "New" Exports in FBU billions 2012-25

3.45 As can be seen from the above chart, the projected operating revenues fully cover the cost of revenue throughout the forecast period. The cost of service from 2019 onwards can only be covered if the projected "new" exports and related export revenues are realized. Without such export revenues, the projected base case Burundi tariffs and revenues will not be adequate to cover the cost of revenue from 2019 to 2023 as illustrated in the following chart. This means that revenues in those years will not fully cover depreciation charges and consequently Burundi tariffs will have to be either set at much higher levels from 2019 onwards or investments funded from internal resources will have to be curtailed.

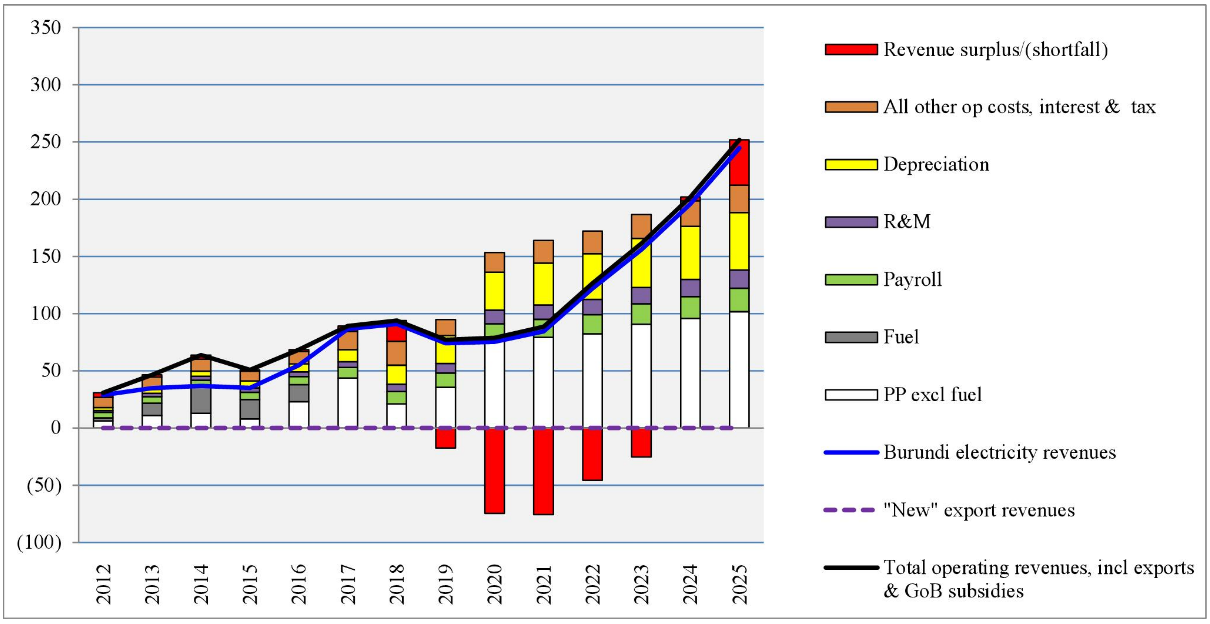

Chart 3: Electricity Cost of Service vs. Operating Revenues, excluding "New" Exports in FBU billions 2012-25

3.46 The structure of REGIDESO's cash operating costs is going to change quite radically over the next few years. The split between fixed and variable costs in 2012 is estimated as 39% fixed and 61% variable. This is forecast to change to 78% fixed and 22% variable by 2025, primarily due to fixed capacity & fixed O&M costs of IPPs.The cost differential between peak and other periods will thus narrow considerably over the next few years.

3.47 The cash flows of REGIDESO's electricity operationsover the forecast period will be healthy if (a) the projected tariff adjustments are implemented, (b) the assumed Government support towards thermal costs in 2013 to 2016 is extended to REGIDESO, (c) the anticipated efficiency improvements in network losses and billing collection are achieved, and (d) the projected funding for REGIDESO's investment plan is secured under the terms assumed in the base case analysis. The table and below shows the summary cash flows in US$ millions to 2025.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
Cash flow from operations	(1.5)	1.9	3.7	1.6	3.6	3.5	22.6	31.3	47.2	36.7	49.9	52.5	55.0	57.8	367.2
Debt service paid	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.3)	(1.3)	(8.1)	(15.2)	(19.4)	(22.4)	(22.4)	(22.4)	(22.4)	(134.1)
Investments	(14.5)	(38.4)	(57.7)	(96.9)	(126.6)	(136.6)	(121.3)	(68.8)	(34.1)	(30.5)	(33.7)	(37.2)	(40.8)	(44.7)	(867.4)
Borrowings	0.0	8.4	19.9	61.8	85.5	92.4	62.0	30.6	5.3	0.0	0.0	0.0	0.0	0.0	366.0
Customer capital contributions & deposits	0.8	4.3	1.1	1.3	1.6	2.1	2.7	3.5	4.4	5.3	6.3	7.3	8.4	9.6	58.0
GoB capital contributions & grants	16.0	19.7	33.7	31.2	36.7	39.3	35.2	12.2	1.3	0.0	0.0	0.0	0.0	0.0	209.3
Net cash inflow/(outflow)	0.8	(4.2)	0.8	(1.0)	0.9	0.3	(0.1)	0.7	8.9	(7.9)	0.0	0.2	0.2	0.3	(1.0)

Table 3: Summary Cash Flows (Electricity) in US$ millions 2012 to 2025

3.48 As can be seen clearly from the above table, REGIDESO will be in a position to meet its operational and other requirements from the projected revenues and Government support. The projected net cash outflows over the next thirteen years to 2025 are forecast at US$1 million, with positive cash balances throughout. Shortfalls in any particular year will be covered from surpluses of earlier years. The debt service burden is forecast to increase dramatically over the next few years, as indicated in the above table. Annual debt service requirements are expected to rise considerably from 2019 onwards as ongoing and new debt mature for debt service payments. The annual debt service payments are forecast to grow from US$1.3 million in 2018 to US$22.4 million from 2022 onwards.

3.49 The likely support required from the Government over the next thirteen years to 2025 is going to be considerable. Government support for REGIDESO's electricity operations over the period 2013 to 2025 is estimated at FBU1,112 billion (US$610 million), including direct budget support of FBU54.7 billion (US$31.8 million) towards thermal costs. Government and donor funding of investments is estimated at FBU1,053 billion

(US$575 million). Total revenues accruing to the Government from REGIDESO's electricity operations over the period 2013 to 2025 are estimated at FBU651 billion (US$310 million).

3.50 Sensitivity analysis was conducted on the base case forecasts presented above. Most of the above sensitivities have a significant impact on REGIDESO's revenue requirements and the impacts of the sensitivities are detailed in Table 39 below.

3.51 The developers of the anticipated Kagunuzi hydro IPP in Burundi and in the regional hydro development projects will enter into long-term (typically 15 to 25 years) power purchase agreements (PPA) with REGIDESO as the off-taker. However, these developers will require Government guarantees for the recovery of their fixed capacity (i.e. investment or capital) and fixed operations & maintenance costs covering the period of the PPA's. Such fixed power purchase costs will rise sharply over the coming years in line with increasing reliance on energy supplies from these sources. The total annual fixed costs are forecast to increase from US$2.3 million in 2013 to US$81.7 million from 2020 onwards. Total fixed charges of IPPs are estimated to amount to US$287.6 million over thirteen years from 2013 to 2025 (refer to Table 40 below).

REGIDESO Electricity Operations Compared

3.52 In terms of its size, Burundi power sector is the second smallest in the region – it is 53% of the size of Rwanda, 9% of Uganda, 3% of Kenya and 5% of Tanzania. Hydro power, including hydro based imports, accounted for 99% of total supply, compared with Rwanda's 57%, Uganda's 59%, Kenya's 45% and Tanzania's 38%. REGIDESO had 76,000 active customers at December 31, 2012, being 26% of EWSA, 17% of Uganda, 5% of Kenya and 8% of Tanzania. The average number of customers per employee of 101 for REGIDESO's electricity operations does not compare well against 232 for Rwanda (electricity operations), 267 for Uganda power sector as a whole, 139 for Kenya (KenGen and KPLC combined) and 153 for TANESCO. However, it should be noted that Umeme (the private operator of Uganda's distribution network) outsources some of its activities and third party employees involved in these activities are not reflected in Uganda's statistics.Burundi's T&D losses of 19.9% were the second lowest. Kenya was the lowest with 17.3% and Uganda highest with 29.1%. Tanzania's losses were 23.1%. The average bulk supply costs of Burundi were the lowest at 0.025US$/kWh sent out. Uganda had the highest costs at 0.124US$/kWh against 0.118 in Rwanda, 0.096 in Kenya and 0.067 in Tanzania. The added costs of land transportation for oil supplies to Burundi, Rwanda and Uganda place them at a disadvantage compared with Kenya and Tanzania. The average retail tariffs in Rwanda and Kenya were the highest at around 0.18US$/kWh, compared with 0.102 in Burundi (second lowest), 0.09 in Tanzania (lowest), 0.112 in Uganda. The crucial difference and the bottom line result is the difference between the actual average end-user tariffs and revenue requirements of the utilities. Burundi had a surplus margin of 11.1% against shortfalls (or subsidies provided by Government) in Rwanda 30.7%, Uganda 55.4% and Tanzania's 34.3%. It is assumed that Kenya's tariffs were fully cost reflective.

3.53 REGIDESO's tariffs were revised in September 2011 and March 2012 (previous increase was in May 2007), resulting in an overall cumulative increase of 69% in the weighted average tariff.EWSA's tariffs were last revised in July 2012 (first since 2006).TANESCO's electricity tariffs were increased on average by 40.3% effective January 15, 2012 (TANESCO had applied for 156% on the basis of "firm" hydro energy output. The regulator disputed this, amongst other assumptions, and amended the assumptions on hydro output to "average" energy). TANESCO had previously adjusted its tariffs by an average of 18.5% effective January 1, 2011; the tariffs were unchanged since January 2008.Electricity tariffs to end-use customers in Uganda were increased on average by 55.5% effective January 15, 2012. The tariffs were previously adjusted on January 1, 2010 which led to an overall decrease of 7.9% of the weighted average tariff. Previous to this the tariffs were unchanged since November 1, 2006. Uganda's latest tariffs are still not fully cost reflective; the average tariff after the increase in January 2012 is estimated at 0.176US$/kWh. In March 2012, the regulator proposed the implementation of an automatic tariff adjustment mechanism (to take account of exchange rate movements, changes in fuel prices and inflation).The proposal is going through a consultative process.Kenya's end-user tariffs are revised regularly to account for the effects of power purchase costs, fuel prices, inflation and exchange rate fluctuations.

3.54 After the implementation of the latest tariff increases, REGIDESO's new average tariff of 0.11US$/kWh will be the lowest. Rwanda and Kenya's weighted average tariffs of around 0.18US$/kWh will be close to those of Uganda (0.176US$/kWh), compared with TANESCO's 0.119US$/kWh. Thermal costs of TANESCO are much lower than those of its neighbors as its generation mix includes 49% of the much lower cost gas fired output.

4 REGIDESO Combined Operations - Recent Performance (2010 to 2012)

4.1 The audit for REGIDESO's 2012 financial statements has not yet been completed. The auditor report for 2011 raises many issues of financial weaknesses and these relate to verification of fixed assets and inventory, proper assessment of work in progress, alignment of depreciation rates with the tax codes, lack of periodic reconciliations of customer billing and accounts between accounting and commercial records and poor billing collection.

4.2 The overall financial performance of REGIDESO (combined water and electricity operations) has progressively improved since 2011 following increases in water and electricity tariffs in September 2011 and March 2012. Water and electricity tariffs were previously revised in May 2007. Prior to the last two tariff increases, the utility's financial performance and its financial position was weak. Financial restructuring of REGIDESO's balance sheet as at December 31, 2008 was undertaken to clear or write-off overdue accounts of the Government, unpaid import bills of SNEL and SINELAC and loans related to investments financed by donors. Import bills of SNEL and SINELEC up to 2007 were settled by GoB and nothing was paid between 2008 and 2010. REGIDESO started paying for its import bills from January 2011 onwards and the overdue bills of SNEL were cleared by September 2012 and the SINELAC debt is expected to be cleared by end 2013.

4.3 The most challenging aspect of assessing the financial performance and financial position of REGIDESO's electricity operations has been to separate or allocate "common" costs, assets and liabilities between water and electricity operations. Estimates have been used where necessary and the basis of allocation is summarized below.

	Basis	Water	Electricity
Common Costs			
Water for own consumption	Estimate	30%	70%
Payroll	Staff nos.	46%	54%
Repairs & maintenance	FA values	43%	57%
Transport & travel	Estimate	30%	70%
Administration & overheads	Estimate	30%	70%
Depreciation	FA values	43%	57%
Provisions for bad debts	Rev split	35%	65%
Provisions for obsolete stock	Inventory values	43%	57%
Common Assets & Liabilities			
Fixed Assets	FA values	43%	57%
Inventories	FA values	43%	57%
Trade receivables	Rev split	35%	65%
Other debtors & prepayments	Rev split	35%	65%
Cash & bank	Rev split	35%	65%
Trade & other payables	Op cost split	37%	63%
Corporate tax payable	Estimate	0%	100%

Table 4: Allocation of Common Costs, Assets & Liabilities of REGIDESO

4.4 Payroll costs have been allocated on the basis of direct staff working for the water and electricity operations. In 2012, 415 staff worked specifically for the water operations (33% of total), 489 for the electricity operations (38% of total) and 369 for the common services (29% of total). Payroll costs allocated on the basis of direct staff numbers would give 46/54 split between water and electricity. In 2011 and 2012, the numbers of customers of REGIDESO accounted for 46% for water and 54% for electricity. The revenue split for water and electricity was35% and 65% in 2012 and 28% and 72% in 2011. It would therefore seem appropriate to allocate thepayroll costs to the water operations within the range of 28% to 46%. In the absence of detailed analysis, it has not been possible to allocate such costs with any reasonable level of confidence. The revenue split of 35/65would probably result in unrealistic allocations. On balance, it is considered that an allocation based on direct staff numbers and revenue split of 46/54 would provide a fairer balance between water and electricity operations respectively.

4.5 Thefinancial performance of REGIDESO's electricity operations, as presented in this report, is assessed in terms of its identifiable revenues, costs, assets and liabilities plus its fair share (as indicated in the above table) of common costs, assets and liabilities of REGIDESO as a whole.

4.6 On the basis of actual revenues and costs that can be directly attributed to water and electricity operations and the allocation of common costs, the utility's revenues and costs for the past two years have been attributed to the two operations as indicated in the following table.

	2012							2011						
	Direct		Common		Overall REGIDESO			Direct		Common		Overall REGIDESO		
	Water	Electricity	Water	Electricity	Water	Electricity	Total	Water	Electricity	Water	Electricity	Water	Electricity	Total
Operating revenues														
Water/electricity revenue	13,915	28,838	0	0	13,915	28,838	42,753	7,634	21,878	0	0	7,634	21,878	29,512
Subsidies	0	869	0	0	0	869	869	0	6,679	0	0	0	6,679	6,679
Other operating revenue	1,230	412	254	592	1,484	1,004	2,487	167	113	165	385	332	498	830
Total operating revenue	15,145	30,119	254	592	15,399	30,711	46,109	7,801	28,670	165	385	7,966	29,055	37,021
Operating expenses														
Electricity purchase & generation fuel	0	8,736	0	0	0	8,736	8,736	0	13,160	0	0	0	13,160	13,160
Chemicals	215	0	0	0	215	0	215	208	0	0	0	208	0	208
Electricity & water for own consumption	2,606	0	64	150	2,671	150	2,821	1,504	0	61	143	1,565	143	1,708
Payroll	0	0	4,299	5,065	4,299	5,065	9,364	53	72	3,581	4,797	3,633	4,869	8,502
Repairs & maintenance	2,333	1,307	146	192	2,480	1,499	3,978	848	2,838	111	108	959	2,946	3,906
Transport, administration & overheads	0	0	1,066	2,486	1,066	2,486	3,552	0	0	1,174	2,739	1,174	2,739	3,913
Depreciation	1,717	2,030	346	452	2,062	2,482	4,545	1,146	1,398	408	398	1,554	1,796	3,350
Provisions for bad debts & stock obsolescence	0	0	2,853	4,679	2,853	4,679	7,532	0	0	2,206	153	2,206	153	2,359
Total operating expenses	6,871	12,074	8,774	13,024	15,645	25,098	40,743	3,759	17,469	7,541	8,338	11,300	25,807	37,106
Operating profit/(loss)	8,274	18,045	(8,520)	(12,432)	(246)	5,612	5,366	4,041	11,201	(7,375)	(7,952)	(3,334)	3,248	(86)
Non-operating income - net	0	0	125	238	125	238	363	0	0	103	262	103	262	364
Finance charges	0	(140)	(119)	(277)	(119)	(417)	(536)	0	(225)	(91)	(212)	(91)	(437)	(528)
Taxation	0	0	0	(1,672)	0	(1,672)	(1,672)	0	0	0	(298)	0	(298)	(298)
Net profit/(loss) after tax														
Including subsidies	8,274	17,905	(8,514)	(14,143)	(239)	3,761	3,522	4,041	10,975	(7,364)	(8,200)	(3,322)	2,775	(547)
Excluding subsidies	8,274	17,036	(8,514)	(14,143)	(239)	2,892	2,653	4,041	4,297	(7,364)	(8,200)	(3,322)	(3,903)	(7,226)

Table 5: Allocation of Revenues & Costs of REGIDESOCombined Operations 2011 & 2012

4.7 REGIDESO as a whole made a net profit after tax of FBU3,522 million[3] (US$2.4 million) in 2012 compared with net losses of FBU547 (US$0.4 million) and FBU767 million (US$0.6 million) in 2011 and 2010 respectively. The financial results take account of the World Bank subsidies towards fuel costs for thermal power generation of FBU869 million (US$0.6 million) in 2012, FBU6,679 (US$5.1 million) in 2011 and FBU4,298 (US$3.5 million) in 2010.

4.8 REGIDESO's combined water and electricity operations generated net cash inflows of FBU2,754 million (US$1.9 million) in 2012 and FBU3,005 million (US$2.3 million) in 2011 and net cash outflow of FBU586 million (US$0.5 million) in 2010; all after receipt of electricity generation fuel subsidies. Without such subsidies, the utility

[3] Unaudited results

would have generated net cash inflows of FBU1,885 million (US$1.3 million) in 2012 and net cash outflows of FBU 3,674 million (US$2.8 million) in 2011 and FBU4,884 million (US$4.0 million) in 2010. The actual net cash flows are summarized in the following table.

		With GoB Subsidies			Without GoB Subsidies		
		Water	Electricity	Total	Water	Electricity	Total
Year to December 31, 2012	FBU million	1,646	1,108	2,754	1,646	239	1,885
	US$ million	1.1	0.8	1.9	1.1	0.2	1.3
Year to December 31, 2011	FBU million	734	2,270	3,005	734	(4,408)	(3,674)
	US$ million	0.6	1.8	2.3	0.6	(3.4)	(2.8)
Year to December 31, 2010	FBU million	(158)	(428)	(586)	(158)	(4,725)	(4,884)
	US$ million	(0.1)	(0.3)	(0.5)	(0.1)	(3.8)	(4.0)

Table 6: Summary Net Cash Flows of REGIDESOCombined Operations 2010 to 2012

4.9 Thenet profits/(losses), cash flows and liquidity of REGIDESO's combined water and electricity operations are summarized in the following table.

REGIDESO (Water & Electricity Operations Combined)			
	2010 Actual	2011 Actual	2012 Actual
Net profit/(loss) after tax			
FBU million	(767)	(547)	3,522
US$ million	(0.6)	(0.4)	2.4
Net cash inflow/(outflow) in year			
FBU million	(586)	3,005	2,754
US$ million	(0.5)	2.3	1.9
Cash & bank balances at December 31 (US$ millio	5.3	7.0	7.9
Current ratio	2.9	2.6	3.5
Debt/equity ratio	15%	13%	11%

Table 7: Summary REGIDESO Financial Performance 2010 to 2012

4.10 The financial position of REGIDESO has improved over the past three years. Based on the utility's financial statements, the current ratio has improved to 3.5 times as at December 31, 2012 (2.6 times at end 2011) and the debt/equity ratio at the last two balance sheet dates were low and ranged between 13% and 11%.However, it should be noted that accounts receivable, as reported in the financial statements, are most probably overstated as they are unlikely to be collected in full.

4.11 According to REGIDESO's billing statistics reported by its independent technical auditor, the overall average billing collection rate based on current year billings for both water and electricity operations has worsened over the past three years - 92.1% in 2010, 82.3% in 2011 and 76% in 2012, giving an average of 83.5% over the past three years. The decline in the collection performance in 2012 is worrying and REGIDESO needs to take all necessary steps to improve its collection performance. The drop in collection may partly be due to the large increases in tariffs and customer bills in 2011/12. According to the financial statements, accounts receivable, net of provisions for bad and doubtful debts, as at December 31, 2012 for both water and electricity operations represented 205 days' annual billing.

4.12 According to the billing statistics of REGIDESO's Commercial department, the overall average billing collection rate based on current year billings for both water and electricity operations over the past three years

(2010 to 2012) was 80.9%. Accounts receivable as at December 31, 2012 represented 371 days' annual billing. The Government and municipalities & communes are bad payers and receivables from all Government entities have accumulated over the years. The average collection rates over the past three years for the Government and municipalities & communes were 61% and 25.2% respectively. The average collection rate for domestic or household customers was 75.7%. Outstanding electricity bills of the Government as a whole as at December 2012 represented 838 days' receivable in terms of annual billing for 2012.The following table shows the commercial statistics by customer category.

	Amount receivable FBU million Dec 2012	Days' receivable Dec 2012	% of total receivables Dec 2012	Average collection rate (1) 2010-12
As per Commercial Department:				
Government	8,566	1,133	7.6%	61.0%
Municipalities & communes	3,844	3,467	1.1%	25.2%
State owned companies	404	98	4.1%	104.5%
Adm. Gest. Person. (Custom Management Administration)	3,218	506	6.4%	62.3%
Total Government	16,033	838	12.9%	69.3%
Households	14,951	321	46.9%	75.7%
General	3,237	199	16.4%	90.7%
Industrial	956	80	12.0%	101.4%
Religious confessions	1,263	291	4.4%	74.3%
Embassies	420	369	1.1%	105.8%
Total REGIDESO (combined water & electrity)	36,860	371	93.6%	80.9%
As per Financial Statements				
Total REGIDESO (combined water & electrity) (2)	24,523	191		84.1%
(1) Average collection rate is based on current year billing				
(2) Days' receivable as per financial statements is after provisions for bad debts				

Table 8: REGIDESO Commercial Statistics

4.13 It is recommended that all uncollectable balances due from the Government and other customers are written-off and cleared from the books of account and the commercial department records. The balances as recorded in the books of account should be reconciled with the commercial department's records and adjustments made as necessary in both sets of records.

5 Electricity Operations – Recent Performance (2010 to 2012)

Operational Performance

5.1 Peak demand in Burundi grew at an annual average rate of 4.46%, rising from 45.5MW in 2009 to 54.0MW in 2012. Electricity sent out during the same period has grown from 207GWh in 2009 to 243GWh in 2010. As a percentage of total supply, hydro output from REGIDESO's plants accounted for 56.1% in 2012 (52% in 2011), hydro imports accounted for 42.7% in 2012 and 2011 and the balance of requirements was met from the Bujumbura thermal plant (1.2% in 2012 and 5.3% in 2011). The use of the Bujumbura thermal plant was restricted due to financial constraints.

5.2 Overall transmission and distribution (T&D) losses averaged 19.5% over the past three years (19.9% in 2012).The losses in 2012 reached 19.9% as per REGIDESO's technical auditor; however, REGIDESO's annual report for 2012 states that the losses were in the region of 24%. The variations in reported losses are due to the unreliability of REGIDESO's billing system. The average losses over the previous four years (2008 to 2011) were 19.7%. It is estimated that about 40% of overall losses can be attributed to technical losses. Metering is considered to be good; although at times meters get locked when power voltage is low and electricity consumption goes unrecorded (approximately 2-3% of losses can be attributed to this). The distribution network needs to be rehabilitated and strengthened. Revenue lost and uncollected for every 1% of T&D losses is estimated at FBU349 million (US$0.226 million), based on the estimated present tariffs and the average collection rate of 84.1%.

5.3 Electricity billed to end-use customers registered growth rates of 14.1% and 5.4% in 2010 and 2011 and declined by 2.3% in 2012, reaching 194.8GWh in 2012. Growth in recent years was limited due to capacity constraints. REGIDESO's own consumption of electricity (mainly for water pumping) accounted for 5% of total energy billed in 2012.

5.4 The ratio of the average number of customers per employee has improved significantly over recent years, rising from 73 in 2009 to 101 in 2012. However, the latest ratio does not compare well with the regional utilities (refer to Section 7 below).

5.5 The operational performance of REGIDESO's electricity operations in recent years is more clearly illustrated in the following chart.

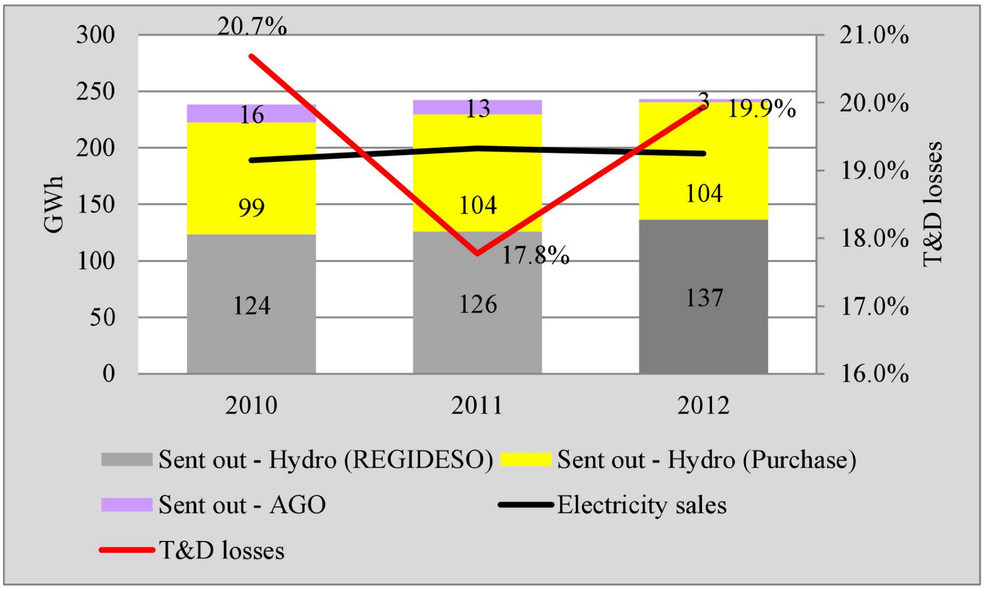

Chart 4: Electricity Operational Performance2010 to 2012

5.6 The following table provides key operational data since January 2010.

Operational	2010 Actual	2011 Actual	2012 Actual
Peak demand Burundi (MW)	50.1	51.7	54.0
Energy sent out (GWh)	238	242	243
of which:			
Hydro (REGIDESO)	52%	52%	56%
Hydro (Purchase)	41%	43%	43%
AGO	7%	5%	1%
Growth in sent out	15.3%	1.7%	0.4%
T&D losses (%)	20.7%	17.8%	19.9%
Electricity sales (GWh)	189	199	195
No. of new customer connections	4,797	6,713	9,307
No. of customers at year-end	59,827	66,540	75,847
of which customers with prepayment meters	25%	47%	43%
Av. no. of customers per employee	80	88	101

Table 9: Electricity - Key Operational Indicators 2010 to 2012

5.7 Total number of electricity customers billed increased by 38% since December 2009 to reach 75,847 by December 31, 2012. New customers connected reached 9,307 in 2012, 6,713 in 2011 and 4,797 in 2010. As at December 31, 2012, customers were connected with prepayment meters accounted for 43% of total customers and 64% of customers were in Bujumbura.Customers with prepayment meters have increased significantly over the past few years – rising from 4,996 in 2007 to 32,985 by December 2012. The World Bank has financed the acquisition and installation of 15,000 prepayment meters under the PMIEE (Projet Multisectoriel Eau et Electricité) project and another 15,000 prepayment meters under the PURSE (Projet d'Urgence pour l'Assistance au Secteur Energétique) project. All new household connections are fitted with prepayment meters and credit meters at existing household and public institution customers are gradually replaced with prepayment meters. Customers with prepayment meters accounted for 31.3% of total electricity sales and 32.5% of total electricity revenue in 2012.

5.8 The mix of customers in 2012 in terms of numbers, sales, revenues and average tariffs are shown in the table below.

	Numbers at December 31		Sales GWh	Revenue FBU mill	Av tariff/kWh FBU	US$
Customers on normal meters:						
Households			22.8%	18.4%	120	0.082
General or commerce			12.0%	13.1%	161	0.111
Industrial			13.4%	11.2%	124	0.085
Adm. à Gestion Personnalisée (Custom Management Administration)			5.8%	4.8%	122	0.084
Government & State organisations			7.0%	7.5%	159	0.109
All other			2.8%	3.8%	202	0.139
REGIDESO consumption for water pumping & offices			4.9%	8.9%	268	0.184
Total customers on normal meters	42,862	57%	68.7%	67.7%	146	0.100
Prepayment meters	32,985	43%	31.3%	32.5%	153	0.105
Difference to agree with financial statements				-0.2%		
Total	75,847	100%	100.0%	100.0%	148	0.102
of which Bujumbura	48,897	64%				

Table 10: Electricity Customer Mix in 2012

Financial Performance

5.9 Thefinancial performance of REGIDESO's electricity operations improved significantly in 2012 following the large tariff increases in September 2011 and March 2012. The full impact of the tariff adjustments will be felt in 2013. The financial performance was helped by the fact that thermal output in 2012 was considerably lower than in the previous two years.

5.10 REGIDESO's electricity operations made net profits of FBU3,761million (US$ 2.6 million) in 2012 and FBU2,775 (US$ 2.1 million) in 2011. The profits are inclusive of WB's fuel subsidies of FBU869 million (US$ 0.6 million) in 2012 and FBU6,679 million (US$ 5.1 million) in 2011. In its 2012 income statements, REGIDESO recorded provisions for bad debts of FBU4,679 million (US$3.2 million), with minimal provisions in earlier years despite the fact that overall billing collection rates were far below 100%. REGIDESO will have to make significant provisions in its 2013 financial statements so as to reflect a true and fair value of accounts receivable. A provision for bad debts of approximately FBU11.1 billion (US$7.2 million)relating to accumulated uncollected billings to end 2012. The financial performance on a comparable basis excluding fuel subsidies and provisions for bad debts would have produced net profits of FBU7,571 million (US$5.2 million) in 2012 and net losses of FBU3,751 million (US$2.9 million) and FBU788 million (US$0.6 million) in 2011 and 2010 respectively.

5.11 REGIDESO's electricity tariffs to customers, as approved by the Ministry of Energy and Mines (MEM), are provided in Annex 8. Electricity tariffs were revised effective September 1, 2011 and March 1, 2012. The energy tariff for the domestic first block (0-50/kWh per month) was reduced by 6.8% effective June 1, 2012. Electricity tariffs were previously revised on May 1, 2007. The impact of the tariff increases in September 2011 and March 2012 were estimated to increase REGIDESO's weighted average electricity revenue by 70.3% (140% for water). The actual cumulative increase in the weighted average electricity tariff to June 1, 2012 is estimated at 69%.

5.12 The actual weighted average electricity revenue increased from 101FBU/kWh (0.082US$/kWh) in 2010 to 110FBU/kWh (0.085US$/kWh) in 2011 and 148FBU/kWh (0.102US$/kWh) in 2012. The present weighted average revenue is estimated at 171FBU/kWh (0.107US$/kWh). In terms of the local currency, the average revenue increased by 8.7% in 2011 and by 34.9% in 2012. In US dollar terms, the average revenue increased by 3.2% in 2010 and 10.4% in 2012.

5.13 Thefollowing chart illustrates the development of REGIDESO's weighted average electricity tariffs over recent years.

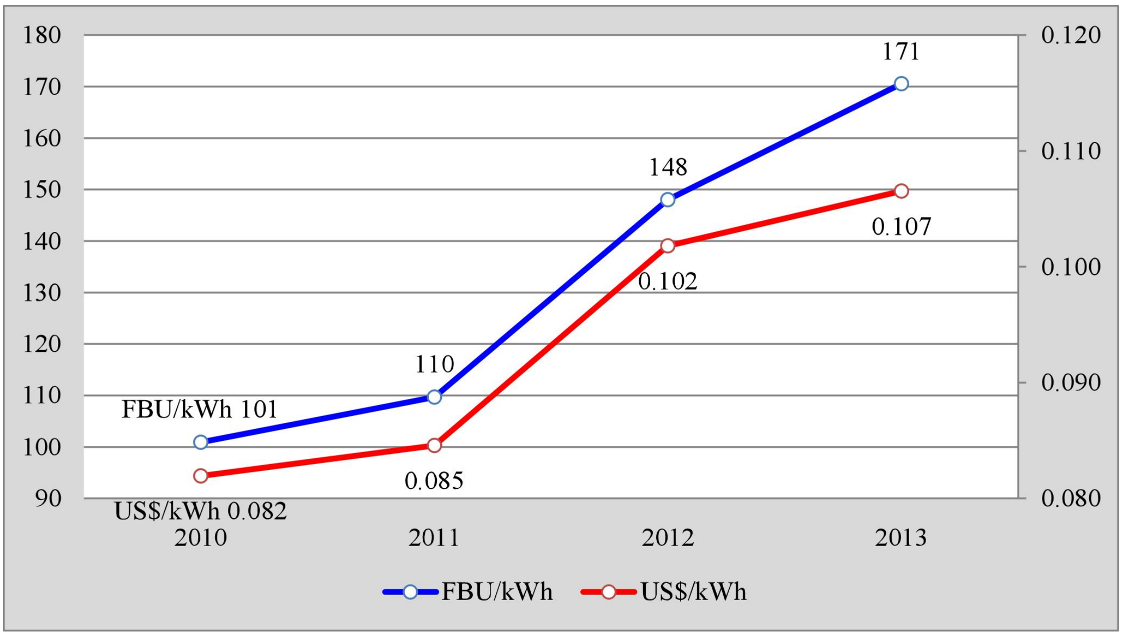

Chart 5: Average Electricity Tariff 2010 to 2013

5.14 The weighted average electricity revenue in 2012 reached 148FBU/kWh (0.102US$/kWh), compared with the cost of service (CoS), excluding fuel subsidies, of 133FBU/kWh (0.092US$/kWh), giving a profit margin of 10%. The CoS includes power purchase costs, fuel costs and all cash operating expenses, recorded provisions for uncollected billings, depreciation of fixed assets based on historical costs, interest charges, and taxation less other operating revenues. No account is taken of any returns on equity. On the basis of cash flow requirements, the average revenue requirements in 2012 amounted to 149FBU/kWh (0.102US$/kWh), almost equal to the average revenue.

5.15 The following chart showsREGIDESO's electricity cost of service,operating revenues and revenue surpluses over the last three years. The operating revenues are inclusive of fuel subsidies and the operating surpluses are after taking account of these subsidies.

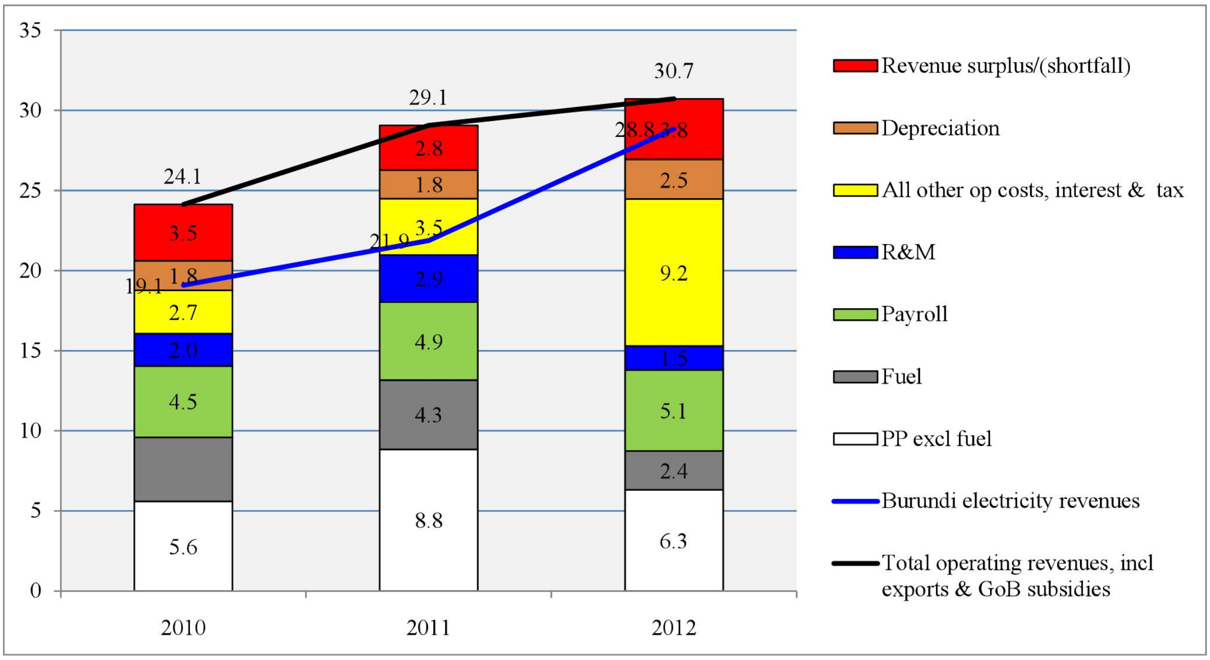

Chart 6: Electricity CoS vs. Op Revenues in FBU billions 2010 to 2012

5.16 The make-up of REGIDESO's electricity operating expenses expressed as percentages of its total operating revenues, including fuel subsidies,over the past three years are illustrated in the following chart.

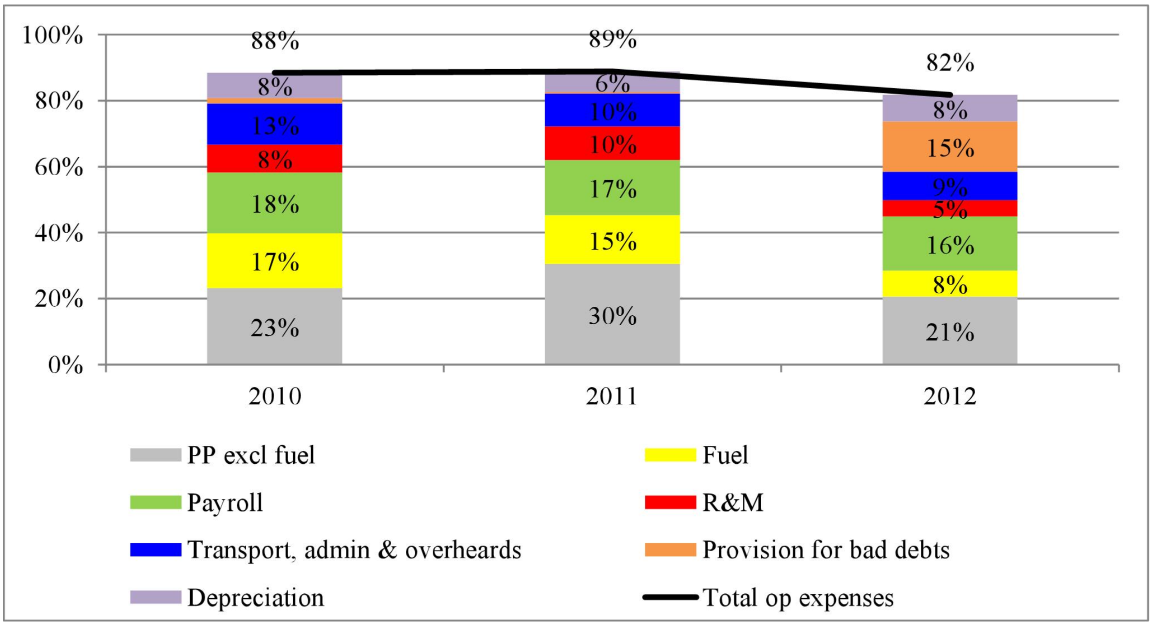

Chart 7: Electricity Operating Costs as % of Operating Revenues 2010 to 2012

5.17 REGIDESO's total operating expenses as a percentage of total operating revenues has ranged between 89% and 82% over the past three years. In 2012, the operating cost structure, as percentages of operating revenues, was made up of power purchase (21%), generation fuel (8%), payroll costs (16%), repairs & maintenance (5%), transport, administration & overheads (9%), provision for bad debts (15%) and depreciation (8%). REGIDESO made minimal provisions for bad debts in 2011 and 2010 although the billing collection rates were around 90%. Total operating expenses in 2012 were 84% of total operating revenues excluding fuel subsidy.

5.18 Power purchase costs represent imports from SNEL (Ruzizi I) and SINELAC (Ruzizi II). The imports in 2012 amounted to 22.2GWh from SNEL and 81.7GWh from SINELAC. The present tariff of SNEL (wholly owned by the Government of DRC) is 0.078US$/kWh and it has remained unchanged since 2009. SINELAC's (jointly and equally owned by the Governments of Burundi, DRC and Rwanda) current tariff effective from January 1, 2010 is 22SDR/MWh (equivalent to 0.034US$/kWh); the previous tariff was 26SDR/MWh and it was set in 2006. According to REGIDESO, the tariff of SINELAC is below its requirements which are estimated at 40SDR/MWh (equivalent to 0.062US$/kWh). The tariffs of both companies are reviewed and revised as and when necessary.

5.19 Payroll costs represent the largest element of controllable operating costs. REGIDESO's staff strength and payroll costs for the electricity operations over the past three years are shown in the following table.

	2010	2011	2012	Average
Domestic inflation	6.4%	9.7%	18.0%	11.4%
Av. no. of employees in year	718	722	704	
% change in no. of employees	2.1%	0.6%	-2.5%	0.04%
Av. no. of customers per employee	80	88	101	
Electricty sales (MWh) per employee	263	276	277	
Payroll costs (FBU millions)	4,453	4,869	5,065	
Payroll costs - % increase	-2%	9%	4%	3.6%
Payroll cost - FBU per kWh sent out	18.675	20.080	20.815	
Payroll cost - FBU per kWh sent out - % change	-15%	8%	4%	-1.4%
Payroll cost - FBU per kWh sold	23.544	24.420	25.997	
Payroll cost as % of electricity revenues	23%	22%	18%	21.0%
Payroll cost - FBU per customer	77,537	77,063	71,149	
Payroll cost - FBU per employee	6,201,463	6,743,583	7,195,768	
Payroll cost - FBU per employee - % change	-4%	9%	7%	3.7%

Table 11: REGIDESO's Staff Strength & Payroll Costs for Electricity Operations 2010 to 2012

5.20 The above table shows that in recent years:

i) The latest employee numbers are at the same level as in 2009 (i.e. no change).

ii) The average number of customers per employee has grown from 80 in 2010 to 101 in 2012. This ratio does not compare well with those of the power utilities in the region (refer to Section 7 below).

iii) Payroll costs have increased annually by an average of 3.6%, compared with annual average inflation of 11.4%.

iv) Payroll costs have ranged between 18% and 23% of electricity revenues.

5.21 Repairs and maintenance costs for REGIDESO's electricity operations over the last three years are shown in the following table.

	2010	2011	2012	Average
R&M costs (FBU millions)	2,023	2,946	1,499	
R&M costs - % increase	-3%	46%	-49%	-2.0%
R&M costs (US$ million)	1.64	2.27	1.03	
R&M costs - % increase	-2%	38%	-55%	-6.3%
R&M cost - US$ per kWh sent out	0.007	0.009	0.004	
R&M cost - US$ per kWh sent out - % incr	-15%	36%	-55%	-11.4%
R&M cost - US$ per kWh sold	0.009	0.011	0.005	
R&M cost as % of electricity revenues	11%	13%	5%	9.8%

Table 12: Repairs & Maintenance Costs for Electricity Operations 2010 to 2012

5.22 The above table shows that in recent years:

i) REGIDESO's expenditures on repairs and maintenance of the network have dropped sharply in 2012.

ii) Repairs & maintenance costs represented 9.8% of electricity revenues over the past three years.

5.23 Transport, administration & overhead costs for REGIDESO's electricity operations over the past three years are shown in the following table.

	2010	2011	2012	Average
Transport + A&O costs (FBU millions)	3,020	2,882	2,636	
Transport + A&O costs - % increase	18%	-5%	-9%	1.6%
Transport + A&O costs (US$ millions)	2.5	2.2	1.8	
Transport + A&O costs - % increase	18%	-9%	-18%	-3.3%
Transport + A&O cost - US$ per kWh sent out	0.010	0.009	0.007	
Transport + A&O cost - US$ per kWh sent out - % inc	2%	-11%	-19%	
Transport + A&O cost - US$ per kWh sold	0.013	0.011	0.009	
Transport + A&O cost as % of electricity revenues	16%	13%	9%	12.7%

Table 13: Transport, Administration & Overhead Costs for Electricity Operations 2010 to 2012

5.24 The above table shows that:

i) Transport, administration & overhead costs have declined each year since 2010.

ii) Transport, administration & overhead costs have accounted for 12.7% of electricity revenues over the past three years.

5.25 The following table provides REGIDESO's income statements and operating ratios of its electricity operations from 2010 to 2013.

	2010 Actual	2011 Actual	2012 Actual
Electricity sales (GWh)	189	199	195
Average electricity revenue (FBU/kWh)	101	110	148
Average electricity revenue (US$/kWh)	0.082	0.085	0.102
	US$ million		
Operating revenue			
Electricity revenue	15.5	16.9	19.8
Other operating revenue	0.6	0.4	0.7
Government subsidies & amortization of grants	3.49	5.15	0.60
Total operating revenue	19.6	22.4	21.1
Operating expenses			
Power purchase excluding fuel	4.5	6.8	4.3
Generation fuel	3.2	3.3	1.7
Payroll	3.6	3.8	3.5
Repairs & maintenance	1.6	2.3	1.0
Transport & travel	0.5	0.6	0.2
Administration & overheads	1.9	1.6	1.6
Operating expenses before depreciation & provisions	15.5	18.4	12.3
Depreciation	1.5	1.4	1.7
Provisions for bad debts & stock obsolescence	0.3	0.1	3.2
Total operating expenses	17.3	19.9	17.3
Operating profit/(loss)	2.3	2.5	3.9
Non-operating income - net	0.8	0.2	0.2
Net finance charges	0.0	(0.3)	(0.3)
Profit/(loss) before taxation	3.1	2.4	3.7
Taxation	0.2	0.2	1.1
Profit/(loss) after taxation	2.8	2.1	2.6
Av. operating profit/(loss) (US$/kWh)	0.012	0.013	0.020
Operating margin (%)	11.6%	11.2%	18.3%
Return on equity (%)	7.7%	5.0%	5.0%

Table 14: Income Statements (US$ millions) & Operating Ratios for Electricity Operations 2010 to 2012

Cash Flows

5.26 The summary cash flows of REGIDESO's electricity operations over the last three years are shown in the following table.

	2010	2011	2012	2010-12
Cash flow from operations	(0.8)	1.8	(1.5)	(0.6)
Debt service paid	(0.05)	(0.17)	(0.10)	(0.3)
Investments	(9.1)	(17.0)	(14.5)	(40.6)
Borrowings	0.0	0.0	0.0	0.0
Customer capital contributions & deposits	1.8	2.0	0.8	4.7
GoB capital contributions & grants	7.8	15.2	16.0	39.0
Net cash inflow/(outflow)	(0.3)	1.8	0.8	2.2

Table 15: Summary Cash Flows for Electricity Operations (US$ millions) 2010 to 2012

5.27 REGIDESO's electricity operations generatednet cash inflows of US$0.8 million and US$1.8 million in 2012 and 2011, compared with net cash outflows of US$0.3 million in 2010.Capital investments in the past three yearsamounted to US$40.6million, largely funded through GoB and donor grants and customer contributions and deposits. Debt service payments were minimal.

Financial Situation

5.28 The summary pro-forma balance sheets of REGIDESO's electricity operationsas at December 31 for the last three years are given in the table below.

	2010	2011	2012
Fixed & other long-term assets	32.1	44.0	50.7
Current assets	26.1	22.2	24.0
Current liabilities	(10.1)	(11.7)	(7.5)
Net current assets	16.0	10.5	16.6
Total assets less current liabilities	48.1	54.5	67.3
Long-term loans (long-term portion)	0.0	0.0	0.0
Customer deposits & capital contributions	8.3	9.4	9.0
Total long-term liabilities	8.3	9.4	9.0
GoB equity	39.8	45.1	58.3
Total equity + debt	48.1	54.5	67.3
Current ratio (times)	2.6	1.9	3.2
Debt/equity ratio (%)	17%	17%	13%

Table 16: Summary Pro-Forma Balance Sheets for Electricity Operations (US$ millions) December 2010 to 2012

	2010	2011	2012
Inventory	11.9	7.0	8.3
Customer accounts receivable	10.2	10.0	10.3
Other debtors & prepayments	0.3	0.3	0.3
Cash at bank and in hand	3.7	5.0	5.1
Total current assets	26.1	22.2	24.0
Less: Current liabilities	(10.1)	(11.7)	(7.5)
Net current assets/(liabilities)	16.0	10.5	16.6

Table 17: Breakdown of Net Current Assets for Electricity Operations (US$ millions) December 2010 to 2012

5.29 REGIDESO had healthy current ratios in recent years as per its financial statements. However, current assets reflect receivables from customers which may not be fully recoverable. The current ratio as at December 31, 2012 would drop by 1.0 to 2.2 times if accounts receivable were stated in the balance sheet at fair value. REGIDESO has no debt and GoB/donor grants for investments have managed to keep the debt/equity ratios low.

6 Electricity Operations - Future Outlook to 2025

Financial Prospects to 2025

6.1 REGIDESO's financial prospects for its electricity operations over the next thirteen years will be largely dictated by the following:

- i) Demand growth, export of surplus energy, and sources and costs of power supply,
- ii) Capital investments and financing thereof (including Government contributions (including donor support extended as equity by GoB),
- iii) Electricity tariffs,
- iv) Operating costs,
- v) Efficiency improvements in network losses, billing collection and operating costs,
- vi) Government support or subsidies towards thermal costs, and
- vii) Borrowing terms for new debt secured for investments.

Financial Projections to 2025

6.2 The base case financial projections of REGIDESO's electricity operations from 2013 to 2025 are presented in nominal prices. The projected key performance indicators, income statements, balance sheets and cash flows in nominal Burundi Francs (FBU) and in US dollars are presented in Annexes 1 to 7.The principal assumptions made in the preparation of the base case financial projections are presented below.

Demand and Supply

6.3 The projected annual electricity demand, energy sent out, network losses, sales to end-use customers and numbers of new customer connections to 2025 are summarized in the following table.

Operational	Minimum target	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak demand Burundi (MW)		54	57	63	69	77	85	94	104	118	132	148	166	184	204
Energy sent out (GWh)															
Burundi		243	256	268	255	306	386	425	473	533	596	670	750	831	925
Exports		0	0	0	0	0	0	120	324	600	539	473	401	328	244
Burundi + Exports		243	256	268	255	306	386	546	798	1,133	1,136	1,143	1,151	1,159	1,168
of which:															
Hydro (REGIDESO)		56%	51%	47%	49%	48%	53%	68%	62%	57%	57%	57%	56%	56%	55%
Hydro (Purchase)		43%	41%	36%	38%	43%	37%	26%	37%	43%	43%	43%	44%	44%	43%
Methane (Purchase)		0%	0%	0%	0%	0%	10%	6%	1%	0%	0%	0%	0%	1%	1%
AGO (REGIDESO/Purchase)		1%	9%	17%	13%	9%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Growth in sent out (Burundi)		0.4%	5.2%	4.9%	-5.0%	20.1%	25.9%	10.3%	11.2%	12.7%	11.8%	12.3%	12.0%	10.7%	11.3%
T&D losses (%)															
Burundi	13.2%	19.9%	19.9%	19.7%	19.5%	19.2%	19.0%	18.7%	18.5%	18.3%	18.0%	17.8%	17.6%	17.3%	17.1%
Burundi + Exports		19.9%	19.9%	19.7%	19.5%	19.2%	19.0%	15.7%	13.0%	11.2%	11.8%	12.5%	13.2%	13.8%	14.6%
Electricity sales (GWh)															
Burundi		195	205	216	205	247	312	346	386	436	489	550	618	687	767
Exports		0	0	0	0	0	0	114	308	570	512	450	381	312	232
Total REGIDESO		195	205	216	205	247	312	460	694	1,006	1,001	1,000	999	999	998
No. of new customer connections		9,307	7,636	8,000	9,000	11,000	14,000	18,000	23,000	28,000	33,000	38,000	43,000	48,000	53,000
No. of customers at year-end		75,847	83,483	91,483	100,483	111,483	125,483	143,483	166,483	194,483	227,483	265,483	308,483	356,483	409,483
Av. no. of customers per employee		101	116	126	138	145	141	137	143	150	164	189	217	247	279

Table 18: Electricity Demand & Supply and Customer Connections 2013 to 2025

6.4 The base case analysis to 2025 as presented in this report assumes that electricity demand in Burundi will grow as per the base case demand growth forecast undertaken in August 2013 by Mr Ananda Covindassamy, Consultant to the World Bank. In view of capacity constraints, the underlying electricity demand up to 2015 will not be fully met. On this basis, demand is expected to grow by 5.2% and 4.9% in 2013 and 2014 respectively, and decline by 5.0% in 2015. The projected capacity additions in 2015/16 will lead to high demand growth of 20.1% in 2016 and 25.9% in 2017. Thereafter, the annual demand growth is forecast to range between 10.3% and 12.3%.

6.5 Peak demand and energy sent out in Burundi is projected to grow from 54MW and 243GWh in 2013 to 204MW and 925GWh by 2025.

6.6 Available energy supply based on the generation expansion plan detailed further below is allocated to meet Burundi demand and any remaining surplus energy is assumed to be exported (firm and non-firm power) on the following basis:

i) Firm power is exported based on the following formula –

a. Total available MW capacity, less
b. Liquid fuel thermal MW capacity, less
c. Burundi MW peak demand plus 15% reserve margin, equals
d. Available firm MW surplus capacity, excluding liquid fuel thermals, less
e. Reserve margin (safety factor) of 5% and planned maintenance of 4% of (d) above, multiplied by
f. Utilization factor of 80% from 2018 onwards, less
g. Cross-border exports, equals
h. Firm MW capacity available for export

ii) Non-firm power is exported based on the following formula –

a. Total available energy (GWh), less

b. Burundi energy demand plus cross-border exports (GWh), less
c. Firm energy available for export (GWh), as in (i) above, equals
d. Energy surplus available for non-firm exports, multiplied by
e. A factor of 90% from 2018 onwards to allow for supply constraints, equals
f. Non-firm energy (GWh) available for export.

6.7 Based on the assumptions detailed above, surplus capacity energy can be exported to the neighbouring countries starting in 2018. The energy surpluses will progressively increase over the years as the projected new capacity comes on line. The projected sent out energy for "new" exports, as considered in this analysis, are summarised in the following table.

	2018	2019	2020	2021	2022	2023	2024	2025
Firm exports	0	0	37	0	0	0	0	0
Non-firm exports	120	324	563	539	473	401	328	244

Table 19: Electricity Sent Out for "New" Exports (GWh) 2018 to 2025

6.8 The above assumptions are critical to the financial viability of REGIDESO if the planned generation expansion is implemented. Net cash inflows arising from such exports account for FBU872 billion (US$415 million) in export revenues, equivalent to 84% of Burundi electricity revenue forecast over the eight years from 2018 to 2025.

6.9 However, there is a huge potential risk for Burundi in that the neighbouring countries also have ambitious generation expansion plans and there is a possibility of available power supply in the region exceeding demand.

6.10 The generation mix (energy sent out) over the forecast period is illustrated Chart 14 below. Transmission and distribution losses are forecast as shown in the table below. It is assumed that the present transmission losses are 5.0% of energy sent out; the actual levels of losses are not known as bulk supply to the distribution network is not currently metered. It is recommended that bulk supply to the distribution network is metered so that the levels of both transmission and distribution losses are correctly identified and monitored. Transmission losses are assumed to remain constant throughout the forecast period. Distribution losses, as a percentage of bulk supply, are forecast to decrease from the assumed present level of 15.7% by 0.25% each year starting 2014. On this basis, the overall transmission and distribution losses for Burundi supply are expected decline from the present 19.9% to 17.1% by 2025.

	Target	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Transmission losses		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Distribution losses		15.7%	15.5%	15.2%	15.0%	14.7%	14.5%	14.2%	14.0%	13.7%	13.5%	13.2%	13.0%	12.7%
T&D losses - Burundi	13.2%	19.9%	19.7%	19.5%	19.2%	19.0%	18.7%	18.5%	18.3%	18.0%	17.8%	17.6%	17.3%	17.1%
T&D losses - Burundi + Exports		19.9%	19.7%	19.5%	19.2%	19.0%	15.7%	13.0%	11.2%	11.8%	12.5%	13.2%	13.8%	14.6%

Table 20: Transmission & Distribution Losses 2013 to 2025

6.11 The following chart illustrates the forecast energy sent out, sales and overall T&D losses.

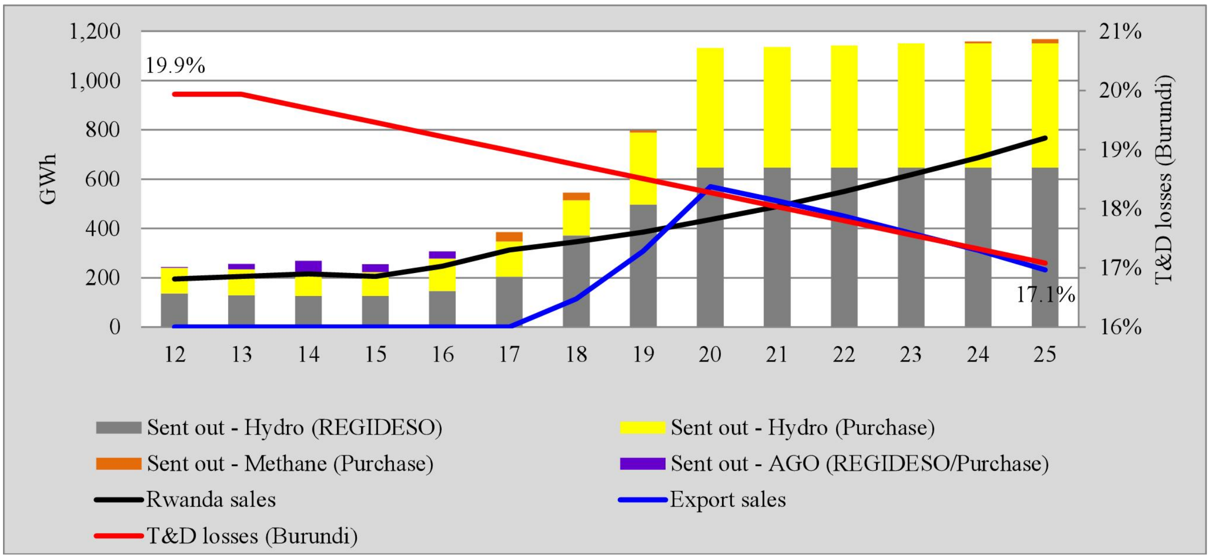

Chart 8: Forecast Energy Sent Out, Sales & T&D Losses 2012 to 2025

Generation Expansion& Electricity Access

6.12 The Government has set ambitious plans to expand the installed generation capacity. The base case analysis presented in this report assumes that the capacity will increase from the existing 68.4MW (including 10MW rental thermal expiring in 2015) to 250MW and increase access to electricity from the present 4.5% to 15.6% by 2025. The challenge of the base case scenario is to (a) attract the needed public/private investments (estimated at US$570 million for generation) as the Government's capacity to provide financing is limited, (b) gradually build-up capacity over time to meet the underlying domestic demand (i.e. avoid idle capacity), (c) recover annual fixed costs (recovery of investment, financing costs, returns on equity and fixed operations and maintenance costs) from electricity customers, and (d) secure Government guarantees (estimated at US$287 million from 2013 to 2025, refer to paragraph 6.78 and Table 41 below) that investors will require as security for the recovery of their fixed capacity charges over the term of their power purchase agreements.

6.13 TheGovernment'svision to 2025 envisages that 25% of the country's population will have access to electricity. The present access rate is estimated at around 4.5%. The Government's target to 2025 is considered to be optimistic as it will require 572,000 new connections over twelve years between 2014 and 2025 (i.e. annual average connections of 47,667) and involving investments of US$277 million approximately.

6.14 The base case analysis presented in this report assumes an electrification program that will involve 326,000 new connections from 2014 to 2025. The electrification program, as assumed in this analysis, is accelerated over the years, starting from 8,000 new connections in 2014 and reaching 53,000 in 2025. Recent history shows that REGIDESO connected 6,713 new customers in 2011 and 9,307 in 2012 (the World Bank financed a large part of the needed investments). REGIDESO plans to connect 7,636 new customers in 2013. The projected new connections program will require investments of US$158 million approximately and access rate is forecast to reach 15.6% by 2025.

6.15 The adopted base case demand scenario is probably optimistic and it will be a challenge for REGIDESO to secure financing and implement the electrification program and generation expansion that this will entail. The financial implications of other demand growth scenarios have been considered in the sensitivity analysis presented further below in paragraph6.75.The following table indicates the electricity access rates in Burundi to 2025, as projected in the base case analysis.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
New connections in year	6,713	9,307	7,636	8,000	9,000	11,000	14,000	18,000	23,000	28,000	33,000	38,000	43,000	48,000	53,000
Customer numbers at December 31 ('000)	66.5	75.8	83.5	91.5	100.5	111.5	125.5	143.5	166.5	194.5	227.5	265.5	308.5	356.5	409.5
Population growth rate		3.34%	3.08%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%
Total population in Rwanda (in millions)	10.2	10.6	10.9	11.2	11.6	11.9	12.3	12.7	13.1	13.5	13.9	14.3	14.8	15.2	15.7
Average number of people in a household	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Population having access to electricity	3.9%	4.3%	4.6%	4.9%	5.2%	5.6%	6.1%	6.8%	7.6%	8.7%	9.8%	11.1%	12.5%	14.0%	15.6%

Table 21: Forecast Electricity Access Rates 2012 to 2025

6.16 The following two tables show the forecast generation expansion plan, the installed and the available MW capacities by plant over the next few years to 2025, as considered in the base case.

	Fuel	Owner	COD	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Mugere	Hydro (REGIDESO)	REGIDESO	1982	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Rwegura	Hydro (REGIDESO)	REGIDESO	1986	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Ruvyironza	Hydro (REGIDESO)	REGIDESO	1980	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Gikonge	Hydro (REGIDESO)	REGIDESO	1982	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nyemanga	Hydro (REGIDESO)	REGIDESO	1987	3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Kayenzi	Hydro (REGIDESO)	REGIDESO	1984	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Marangara	Hydro (REGIDESO)	REGIDESO	1986	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mpanda	Hydro (REGIDESO)	REGIDESO	2016	0	0	0	0	10	10	10	10	10	10	10	10	10	10
KABU 16	Hydro (REGIDESO)	REGIDESO	2018	0	0	0	0	0	0	20	20	20	20	20	20	20	20
Jiji	Hydro (REGIDESO)	REGIDESO	2017	0	0	0	0	0	32	32	32	32	32	32	32	32	32
Mulembwe	Hydro (REGIDESO)	REGIDESO	2019	0	0	0	0	0	0	0	17	17	17	17	17	17	17
Ruzibazi	Hydro (REGIDESO)	REGIDESO	2020	0	0	0	0	0	0	0	0	17	17	17	17	17	17
KITE 20 (Masango)	Hydro (REGIDESO)	REGIDESO	2020	0	0	0	0	0	0	0	0	8	8	8	8	8	8
Kagunuzi	Hydro (Purchase)	IPP	2016	0	0	0	0	8	8	8	8	8	8	8	8	8	8
Bujumbura thermal plant	Thermal (REGIDESO)	REGIDESO	1996	6	11	11	11	11	11	11	11	11	11	11	11	11	11
Emergency Power (Interpetrol)	Thermal (Purchase)	IPP	2013	0	10	10	0	0	0	0	0	0	0	0	0	0	0
Ruzizi I (DRC)	Hydro (Purchase)	SNEL	1957	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Ruzizi II (DRC)	Hydro (Purchase)	SINELAC	1989	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Ruzizi III (DRC)	Hydro (Purchase)	IPP	2020	0	0	0	0	0	0	0	0	47	47	47	47	47	47
Rusumo Falls (B, R& T)	Hydro (Purchase)	IPP	2019	0	0	0	0	0	0	0	27	27	27	27	27	27	27
Akanyaru (B & R)	Hydro (Purchase)	IPP	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ruzizi IV (DRC)	Hydro (Purchase)	IPP	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lac-Kivu (EWSA)	Methane (Purchase)	IPP	2017	0	0	0	0	0	7	7	7	7	7	7	7	7	7
Total installed capacity available to REGIDESO (MW)				**53**	**68**	**68**	**58**	**77**	**115**	**135**	**178**	**251**	**251**	**251**	**251**	**251**	**251**
of which:																	
Hydro (REGIDESO)				61%	47%	47%	55%	56%	65%	70%	62%	54%	54%	54%	54%	54%	54%
Hydro (Purchase)				29%	23%	23%	27%	31%	20%	17%	28%	39%	39%	39%	39%	39%	39%
Methane (Purchase)				0%	0%	0%	0%	0%	6%	5%	4%	3%	3%	3%	3%	3%	3%
Liquid fuel				10%	30%	30%	18%	14%	9%	8%	6%	4%	4%	4%	4%	4%	4%
of which:																	
REGIDESO				71%	63%	63%	73%	69%	74%	78%	68%	59%	59%	59%	59%	59%	59%
IPP's				29%	37%	37%	27%	31%	26%	22%	32%	41%	41%	41%	41%	41%	41%

Table 22: Generation Expansion Plan (Installed MW Capacities) 2012 to 2025

	Fuel	Owner	COD	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Mugere	Hydro (REGIDESO)	REGIDESO	1982	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Rwegura	Hydro (REGIDESO)	REGIDESO	1986	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Ruvyironza	Hydro (REGIDESO)	REGIDESO	1980	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gikonge	Hydro (REGIDESO)	REGIDESO	1982	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nyemanga	Hydro (REGIDESO)	REGIDESO	1987	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Kayenzi	Hydro (REGIDESO)	REGIDESO	1984	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Marangara	Hydro (REGIDESO)	REGIDESO	1986	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mpanda	Hydro (REGIDESO)	REGIDESO	2016	0	0	0	0	5	5	5	5	5	5	5	5	5	5
KABU 16	Hydro (REGIDESO)	REGIDESO	2018	0	0	0	0	0	0	14	14	14	14	14	14	14	14
Jiji	Hydro (REGIDESO)	REGIDESO	2017	0	0	0	0	0	17	17	17	17	17	17	17	17	17
Mulembwe	Hydro (REGIDESO)	REGIDESO	2019	0	0	0	0	0	0	0	11	11	11	11	11	11	11
Ruzibazi	Hydro (REGIDESO)	REGIDESO	2020	0	0	0	0	0	0	0	0	12	12	12	12	12	12
KITE 20 (Masango)	Hydro (REGIDESO)	REGIDESO	2020	0	0	0	0	0	0	0	0	3	3	3	3	3	3
Kagunuzi	Hydro (Purchase)	IPP	2016	0	0	0	0	6	6	6	6	6	6	6	6	6	6
Bujumbura thermal plant	Thermal (REGIDESO)	REGIDESO	1996	4	9	9	9	9	9	9	9	9	9	9	9	9	9
Emergency Power (Interpetrol)	Thermal (Purchase)	IPP	2013	0	10	10	0	0	0	0	0	0	0	0	0	0	0
Ruzizi I (DRC)	Hydro (Purchase)	SNEL	1957	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Ruzizi II (DRC)	Hydro (Purchase)	SINELAC	1989	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Ruzizi III (DRC)	Hydro (Purchase)	IPP	2020	0	0	0	0	0	0	0	0	25	25	25	25	25	25
Rusumo Falls (B, R& T)	Hydro (Purchase)	IPP	2019	0	0	0	0	0	0	0	18	18	18	18	18	18	18
Akanyaru (B & R)	Hydro (Purchase)	IPP	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ruzizi IV (DRC)	Hydro (Purchase)	IPP	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lac-Kivu (EWSA)	Methane (Purchase)	IPP	2017	0	0	0	0	0	5	5	5	5	5	5	5	5	5
Total available capacity to REGIDESO (MW)				**30**	**45**	**45**	**35**	**45**	**67**	**81**	**109**	**150**	**150**	**150**	**150**	**150**	**150**
of which:																	
Hydro (REGIDESO)				50%	33%	33%	42%	44%	54%	62%	56%	51%	51%	51%	51%	51%	51%
Hydro (Purchase)				39%	26%	26%	33%	38%	25%	21%	32%	40%	40%	40%	40%	40%	40%
Methane (Purchase)				0%	0%	0%	0%	0%	8%	7%	5%	4%	4%	4%	4%	4%	4%
Liquid fuel				12%	41%	41%	24%	19%	13%	10%	8%	6%	6%	6%	6%	6%	6%
of which:																	
REGIDESO				61%	52%	52%	67%	62%	67%	73%	63%	56%	56%	56%	56%	56%	56%
IPP's				39%	48%	48%	33%	38%	33%	27%	37%	44%	44%	44%	44%	44%	44%

Table 23: Generation Expansion Plan (Available MW Capacities) 2012 to 2025

6.17 Total installed capacity is set to increase over the next thirteen years from 53MW in December 2012 to 251MW by December 2025. REGIDESO owned installed capacity is forecast to decline over the years from 71% in 2012 to 59% by 2025.

Investment Plan

6.18 REGIDESO's investment requirements in the extension, reinforcement and rehabilitation of the transmission and distribution networks over the next thirteen years to 2025are considerable and the levels of investments undertaken will largely depend on the availability of funding from donors, REGIDESO and GoB. REGIDESO's capacity to provide funding out of internal resources will be determined by the levels of electricity tariffs, collected revenues, customer contributions to new connections, and revenue requirements. The investment plan is based on ongoing and planned Government and donor funded projects, REGIDESO's investment budget for 2013 and the tariff study conducted in November 2010. Investment requirements beyond 2017 are not clearly defined and for the purposes of this analysis, it is assumed that US$10 million (in 2013 prices) will be invested each year from 2018 to 2025 in the extension and rehabilitation of the transmission and distribution network. The number of new customer connections and the related investments as detailed in paragraph 6.15 above are included in the following investment plan which has been considered in the base case financial projections.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25	
Investments:															
Hydro generation	13	25	66	88	98	64	36	7	1	1	1	1	1	401	46%
Thermal generation	4	0	0	0	0	0	0	0	0	0	0	0	0	4	0.4%
Transmission	8	27	25	32	30	36	8	0	0	0	0	0	0	166	19%
Distribution	12	5	5	6	7	20	23	26	29	32	35	39	43	281	32%
Buildings, vehicles, office furniture & equip	1	1	1	1	1	1	1	1	1	1	1	1	1	15	2%
Total investments	38	58	97	127	137	121	69	34	31	34	37	41	45	867	100%
Finanacing plan:															
Own resources	6	3	3	3	3	22	23	23	25	28	30	33	35	235	27%
Customer contributions	4	1	1	2	2	3	3	4	5	6	7	8	9	57	7%
Borrowing	8	20	62	86	92	62	31	5	0	0	0	0	0	366	42%
Grants	20	34	31	37	39	35	12	1	0	0	0	0	0	209	24%
Total investments	38	58	97	127	137	121	69	34	31	34	37	41	45	867	100%

Table 24: Electricity Investment Plan (US$ millions) 2013 to 2025

6.19 The projected total investment requirements over the next thirteen years to 2025 are estimated at US$867million (excluding generation investments to be undertaken by IPPs), equivalent to annual average investments of US$67 million. The projected financing plan for such investments will require 27% funding (US$235 million) from internal resources, 7% funding (US$57 million) from customer contributions, 42% funding (US$366 million) through borrowing (on-lent GoB/donor funds) and the remaining 24% funding (US$209 million) from Government and donor grants. A large part of proposed borrowing and grants is under negotiation or unsecured. Increasing depreciation allowances in the tariff will enable REGIDESO to finance a larger proportion of investments in the future.

6.20 The following table shows the make-up of investments considered in the base case projections.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
Mpanda hydro	10.5	12.6	12.6	6.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.2
KABU 16 hydro	0.0	0.0	20.0	24.0	24.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.0
Jiji hydro	0.0	12.3	24.5	20.4	20.4	4.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	81.7
Mulembwe hydro	0.0	0.0	8.2	16.4	13.7	13.7	2.7	0.0	0.0	0.0	0.0	0.0	0.0	54.7
Ruzibazi hydro	0.0	0.0	0.0	11.6	23.2	19.4	19.4	3.9	0.0	0.0	0.0	0.0	0.0	77.4
KITE 20 (Masango) hydro	0.0	0.0	0.0	8.3	16.6	13.8	13.8	2.8	0.0	0.0	0.0	0.0	0.0	55.4
Rehabilitation of Hydros (REGIDESO funded)	1.3	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	8.1
PMIRE - 220kV TL - Kigoma-Gitega (EU/KfW funded)	0.0	8.4	8.4	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1
PMIRE - 220kV TL - Kamanyola-Bujumbura (AfDB/KfW funded)	5.1	18.2	9.9	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.1
Inter-connection Rusumo-Gitega (Burundi) (ADF Project)	0.0	0.0	0.0	0.0	18.1	22.7	4.5	0.0	0.0	0.0	0.0	0.0	0.0	45.3
PMIEE - IDA Project SDR30.4 million	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1
PURSE - IDA Project US$15.4 millin	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
110kV TL (80km) Jiji & Mulembwe Plants to Bujumbura South (WB funded)	0.0	0.0	6.9	13.8	11.5	11.5	2.3	0.0	0.0	0.0	0.0	0.0	0.0	46.1
Distribution Projects (REGIDESO funded)	3.5	1.1	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	10.9
Rural Electrification (REGIDESO funded)	0.5	0.4	0.5	0.5	0.7	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	7.9
Rehabilitation of HT lines	0.0	0.0	0.0	0.0	0.0	2.3	1.5	0.0	0.0	0.0	0.0	0.0	0.0	3.8
Extension & Rehabilitation of Network - beyond 2017	0.0	0.0	0.0	0.0	0.0	11.0	11.3	11.6	11.9	12.2	12.5	12.9	13.3	96.8
New customer connections	4.2	3.3	3.7	4.7	6.1	8.0	10.4	13.0	15.7	18.5	21.6	24.8	28.1	162.0
Buildings, Vehicles, Office F&F, Computers, etc	1.5	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	15.1
Total investments (US$ millions)	38.4	57.7	96.9	126.6	136.6	121.3	68.8	34.1	30.5	33.7	37.2	40.8	44.7	867.4

Table 25: Investments by Project 2013 to 2025

Efficiency Improvements – Network Losses, Billing and Billing Collection

6.21 The present overall T&D losses and the average collection rate relating to Burundi electricity consumption are 19.9%and 84.1% respectively.On the basis of current performance, 32.7% of electricity sent out is not paid for. Revenue lost and uncollected for every 1% of T&D losses is estimated at FBU349 million (US$0.226 million), based on energy sent out in 2012, existing tariffs and an average billing collection rate of 84.1%.Assuming optimum network losses of 13% and billing collection rate of 97.5%, FBU2.75 billion (US$1.8 million) can be recovered annually through efficiency gains. This is the level of the challenge facing both REGIDESO and the Government.

6.22 If the assumed reductions in distribution losses each year of 0.25% over the next twelve years are achieved, and based on the projected average tariffs, there will be a positive cash flow impact of US$10 million to 2025.

6.23 If the assumed improvements in the overall Burundibilling collection rate of 1.5% each year (increasing from the present 84% to 96% by 2025), and based on the projected average tariffs and network losses, there will be a positive cash flow impact of US$56 million to 2025.

REGIDESO's Electricity Revenue Requirements and Financing Plan 2012/13 to 2019/20

6.24 REGIDESO's forecast revenue requirements over the next threeto four years will remain high as long as long it has to rely on thermal power supply to 2016 and the expensive hydro supply from the proposed Kagunuzi IPP which comes on line in 2016. This situation is forecast to continue through to 2017 before cheaper donor funded hydro plants (Jiji, KABU 16 and Mulembwe) come on line from late 2017 to 2019. The forecast revenue requirements to 2025 will not be met through present electricity tariffs. The level of Government support in meeting future electricity revenue requirements is matter of Government policy; it is a trade-off between (a) subsidies to electricity consumers, who are generally the better-offs in society, and (b) support to other sectors, such as health, education, social welfare, etc that benefits the wider population. The important element of electricity pricing is to ensure that life-line electricity consumers are protected at all times. The life-line monthly consumption band was progressively reduced from 150kWh to 100kWh in September 2011 and to 50kWh in March 2012. The present life-line monthly consumption band in Uganda is 0-15kWh and 0-50kWh in Kenya and Tanzania.

6.25 REGIDESO's base case forecast annual revenue requirements are expected to increase from FBU16.3 billion (US$11.2 million) in 2012 to FBU44.3 billion (US$27.7 million) in 2013, FBU55.4 billion (US$32.8 million) in 2014 and FBU44.0 billion (US$25.1 million) in 2015 (the drop in 2015 is due to the retirement of the rental thermal in April 2015). Revenue requirementsin 2016 and 2017 are expected to increase to FBU58.8 billion (US$32.4 million) and FBU70.7 billion (US$37.7 million) respectively (largely due to "new" power purchase costs relating to Kagunuzi hydro IPP and Lake Kivu methane based supply from EWSA). In the subsequent three years, the revenue requirements are forecast to reach FBU119.4 billion (US$62.0 million) in 2018 (increase largely due to new debt service requirements), FBU162.8 billion (US$82.3 million) in 2019 (increase largely due to "new" supply from Rusumo hydro and investments to be funded from internal resources), FBU220.3 billion (US$108.8 million)in 2020 (increase largely due to "new" supply rom Ruzizi III hydro higher). The annual requirements in the subsequent five years are expected to increase gradually from FBU242.5 billion (US$226.4 million) in 2021 to FBU321.8 billion (US$142.1 million) by 2025.

6.26 Electricity revenues based on present tariffs (last revised in June 2012) will not be fully adequate to meet such requirements. REGIDESO will continue to require GoB support towards thermal costs and upward tariff revisionsin 2016/17. Tariffs beyond 2017 can be reduced if surplus energy can be exported at the levels and tariffs as forecast in this analysis. The projected financing gap in 2013 and beyond will need to be closed by a combination of tariff and non-tariff measures. The needed tariff increases will depend on the level of available budgetary support from the Government.

6.27 The base case forecast revenue requirements, electricity revenues (based on present tariffs) and revenue surpluses/shortfalls of REGIDESO's electricity operations, together with a proposed financing plan to meet the projected revenue shortfalls from 2013 to 2025 are summarized in the table below.

	Actual	Forecast															
		FBU billions														US$ mln	% of
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-2025		total
Revenue requirements																	
Operating costs & taxation, excl depreciation	19.6	34.6	50.5	39.3	53.9	64.2	74.3	90.1	140.2	143.1	154.1	163.1	176.1	191.1	1,375	672	63%
Debt service requirements	0.1	0.1	0.0	0.0	0.0	1.0	3.8	28.3	33.4	47.0	48.2	49.3	50.3	51.4	313	147	14%
Investments funded from own resources	(3.5)	9.6	4.9	4.6	4.9	5.4	41.3	44.4	46.7	52.3	58.3	64.9	71.9	79.4	489	234	22%
	16.3	44.3	55.4	44.0	58.8	70.7	119.4	162.8	220.3	242.5	260.6	277.2	298.3	321.8	2,176	1,052	100%
Less: Collected revenues																	
Burundi electricity revenues (based on present tariffs)	22.5	29.4	31.5	30.5	37.4	48.0	54.0	61.2	70.3	80.1	91.5	102.8	114.2	127.5	878	431	40%
Export electricity revenues	0.0	0.0	0.0	0.0	0.0	0.0	29.0	82.4	157.9	150.9	139.1	123.9	106.5	83.1	873	415	40%
Other revenues	1.2	2.0	2.4	2.5	2.7	2.9	3.2	3.5	3.9	4.4	5.0	5.7	6.5	7.5	52	26	2%
	23.7	31.4	33.8	33.0	40.1	50.9	86.2	147.1	232.1	235.4	235.6	232.4	227.3	218.0	1,803	871	83%
Revenue shortfall before tariff support & future tariff increases	7.4	(13.0)	(21.6)	(10.9)	(18.8)	(19.7)	(33.2)	(15.7)	11.8	(7.0)	(25.0)	(44.8)	(71.0)	(103.8)	(373)	(181)	-17%
Indicative Financing Plan																	
I. Government tariff support (subsidies towards thermal costs)																	
Direct budget support	0.0	5.0	25.0	13.5	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55	32	3%
IDA support	0.9	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5	3	0.2%
Total Government support	0.9	9.9	25.0	13.5	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60	35	3%
II. Tariff increases post June 2012																	
Addional collected revenues	0.0	0.0	0.0	0.0	11.2	30.0	29.4	7.8	1.0	1.1	27.3	49.4	76.8	111.3	345	162	16%
Tariff increase in year	34.9%	0.0%	0.0%	0.0%	30.0%	25.0%	-5.0%	-27.0%	-10.0%	0.0%	28.0%	14.0%	13.0%	12.0%	87.3%		
Cumulative tariff increase post June 2012		0.0%	0.0%	0.0%	30.0%	62.5%	54.4%	12.7%	1.4%	1.4%	29.8%	48.0%	67.2%				
Date of tariff increase	March & June 12	Jan 13	Jan 14	Jan 15	Jan 16	Jan 17	Jan 18	Jan 19	Jan 20	Jan 21	Jan 22	Jan 23	Jan 24	Jan 25			
Total financing	0.9	9.9	25.0	13.5	22.4	30.0	29.4	7.8	1.0	1.1	27.3	49.4	76.8	111.3	405	197	19%
Remaining surplus/(shortfall) in year	8.3	(3.0)	3.4	2.5	3.7	10.3	(3.8)	(7.9)	12.8	(5.9)	2.3	4.5	5.8	7.5	32	16	1%
Opening surplus/(deficit)	0.0	8.3	5.2	8.6	11.2	14.8	25.1	21.2	13.3	26.1	20.2	22.5	27.1	32.8	8	5	
Closing surplus/(deficit)	8.3	5.2	8.6	11.2	14.8	25.1	21.2	13.3	26.1	20.2	22.5	27.1	32.8	40.3	40	21	2%
Cash & bank balance at December 31	8.0	1.2	2.5	0.7	2.3	2.9	2.7	4.0	22.1	5.7	5.8	6.2	6.6	7.3	7	3	

Table 26: Electricity Revenue Requirements, Revenues& Indicative Financing Plan 2012 to 2025

6.28 The above table clearly shows the large funding gap between the projected revenue requirements and collected revenues. The funding shortfalls over the next thirteen years are estimated to amount to FBU373 billion (US$181 million), equivalent to 17% of the total revenue requirements. A combination of tariff and non-tariff measures will be needed to close the financing gap.Government support towards thermal costs will not be required from 2017 onwards and there will be scope to reduce electricity tariffs in 2018 to 2020, as indicated in the above table.

6.29 Theabove financing plan, envisages the following revenue raising measures:

i) Government tariff support: IDA support towards fuel costs of thermal power generation in 2013 is estimated to contribute FBU4.9 billion (US$3.06 million). In addition to this support, the base case analysis assumes that the Government will finance in full the remaining thermal costs relating to the rental thermal and 75% of fuel costs of REGIDESO’s Bujumbura thermal plant in 2013 to 2016, amounting in total to FBU5.0 billion (US$3.1 million) in 2013, FBU25.0 billion (US$14.8 million) in 2014, FBU13.5 billion (US$7.7 million) in 2015, and FBU11.2 billion (US$ 6.2 million) in 2016. These direct subsidies have been introduced so as to moderate the tariff increases proposed below. The projected GoB support (including IDA) is equivalent to 22.4% (in 2013), 45.1% (in 2014), 30.6% (in 2015), and 19.0% (in 2016) of the total revenue requirements in each of those years. These figures show that GoB support is crucial over the next four years, and without such support, the needed tariffs would have to be raised to levels that will be unsustainable.

ii) Electricity tariffs: According to the latest World Bank forecast, international prices of crude oil are expected to remain more or less constant at around US$100 (in nominal prices) per barrel up to

2020. The World Bank forecast has been adopted in the base case analysis presented in this report. The crude oil price beyond 2020 is kept constant at US$100/barrel. Based on this oil price scenario, and after taking account of GoB support (as indicated above), the base case financial analysis assumes that the following tariff adjustments will be implemented to meet the revenue requirements of REGIDESO over the forecast period to 2025.

- + 30% on January 1, 2016
- + 25% on January 1, 2017
- - 5% on January 1, 2018
- - 27% on January 1, 2019
- -10% on January 1, 2020
- + 28% on January 1, 2022
- + 14% on January 1, 2023
- + 13% on January 1, 2024
- + 12% on January 1, 2025

Additional collected revenues raised through such tariff increases are estimated to raise FBU11.2 billion (US$6.2 million) in 2016, FBU30.0 billion (US$16.0 million) in 2017, and FBU29.4 billion (US$15.2 million) in 2018. In the subsequent three years to 2021, the additional collected revenues will be considerably lower in view of the projected tariff decreases in these three years. Tariff increases in the following four years to 2025 will provide additional collected revenues. The financial impact of the projected tariff adjustments over the entire forecast period from 2013 to 2025 is estimated to add FBU349 billion (US$162 million), and accounting for 16% of the revenue requirements over the entire forecast period. The projected tariff increases and the tariff path are considered in the next section.

6.30 REGIDESO's electricity revenues include electricity consumed the utility's water operations (largely for water pumping). It is assumed that this revenue will be recovered from water consumers (i.e. recovered through water tariffs). In 2012, such revenues accounted for 10.4% of REGIDESO's total electricity revenues in Burundi.

6.31 The following two charts show the Burundi collected revenues and revenue requirements (net of export revenues) in US$ millions and US$/kWh over the forecast period. The charts show that the projected revenue requirements are adequately covered by the collected revenues in all but two years. The projected small revenue shortfalls in 2018, 2019 and 2021 will covered through surpluses in previous years.

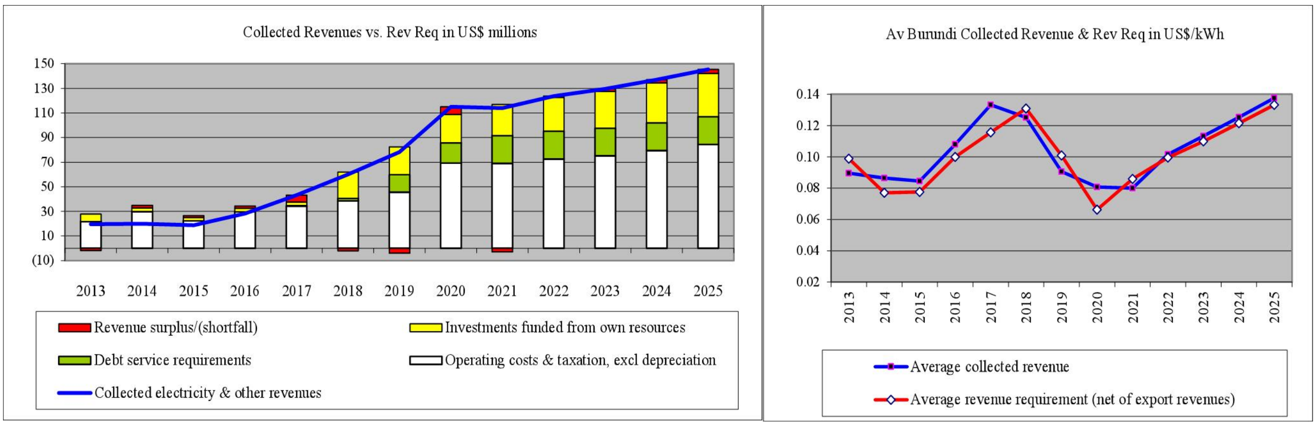

Chart 9: Electricity Collected Revenues vs. Revenue Requirements 2012 to 2025

Projected Retail Tariff Path to 2025

6.32 The following table and chart show the base case projected levels of the weighted average retail electricity tariff to 2025.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Forecast												
Date of tariff increase	March & June 12	Jan 13	Jan 14	Jan 15	Jan 16	Jan 17	Jan 18	Jan 19	Jan 20	Jan 21	Jan 22	Jan 23	Jan 24	Jan 25
Average tariff increase	35%	0%	0%	0%	30%	25%	-5%	-27%	-10%	0%	28%	14%	13%	12%
Cumulative tariff increase post June 2012	35%	0%	0%	0%	30%	63%	54%	13%	1%	1%	30%	48%	67%	87%
Weighted average tariff at date of tariff adjustment														
FBU/kWh in nominal prices	171	171	171	171	222	277	263	192	173	173	221	252	285	319
US$/kWh in nominal prices	0.110	0.103	0.099	0.095	0.120	0.146	0.135	0.096	0.084	0.082	0.103	0.115	0.127	0.140
FBU/kWh in 2012 prices	171	156	148	140	172	205	185	129	110	105	128	139	150	160
US$/kWh in 2012 prices	0.110	0.101	0.096	0.090	0.111	0.133	0.120	0.083	0.071	0.068	0.083	0.090	0.097	0.103

Table 27: Projected Retail Electricity Tariff Path 2012 to 2025

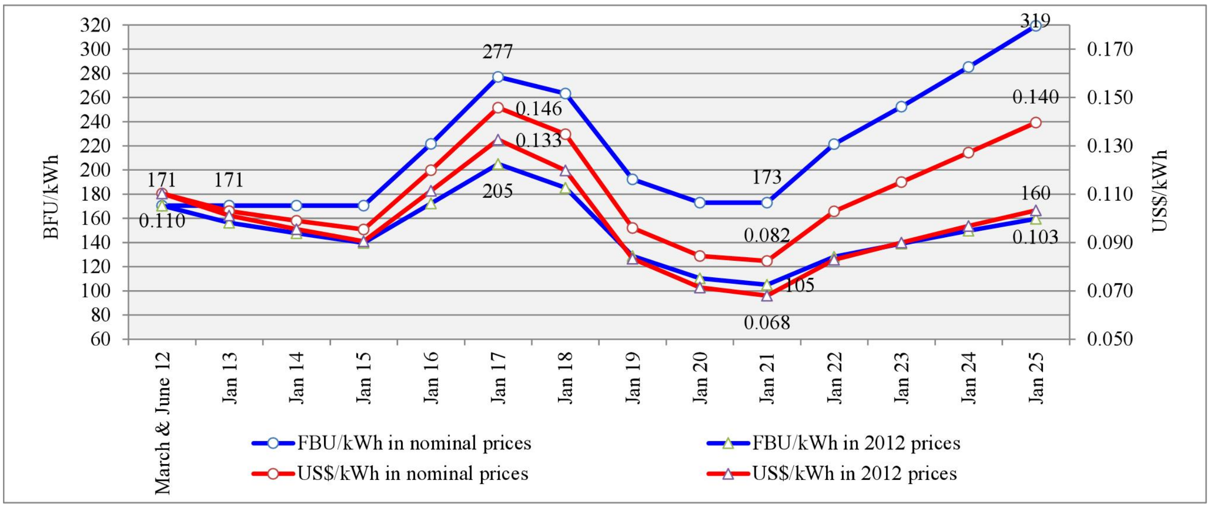

Chart 10: Projected Retail Electricity Tariff Path 2012 to 2025

6.33 Under the base case tariff scenario, the weighted average retail tariff is estimated to increase from the present 171FBU/kWh (0.110US$/kWh) to 277FBU/kWh (0.146US$/kWh) by January 2017. After peaking at these levels, there will be scope to reduce tariffs as costs of supply come down. The weighted average tariff is projected to drop to 173FBU/kWh (0.084US$/kWh) by January 2020(all tariffs in nominal prices). The first tariff increases will be required in January 2016 and 2017, projected cumulatively at 63% in FBU terms and by 53% in US$ terms. Over the subsequent three years, tariffs are forecast to drop from 277FBU/kWh (0.146US$/kWh) in 2017 to 173FBU/kWh (0.084US$/kWh) by January 2020 (dropping back to similar levels as in 2013). Tariffs are forecast to remain flat in the following year(2021) andannual increases ranging from 28% to 12% will be needed in the subsequent four years (2022-25). The average tariff in 2025 is estimated to reach 319FBU/kWh (0.140US$/kWh) in nominal prices, and 160FBU/kWh (0.103US$/kWh) in 2012 prices.

Alternative Tariff Scenarios to 2017

6.34 The table below shows the tariff increases and tariff levels that will be required under alternative assumptions concerning direct budget support from the Government towards thermal costs from 2013 to 2017.

	2013	2014	2015	2016	2017	Cumulative
Date of tariff increase	Jan 13	Jan 14	Jan 15	Jan 16	Jan 17	
Base case						
Tariff increase	**0%**	**0%**	**0%**	**30%**	**25%**	**63%**
Av tariff (US$/kWh in nominal prices)	0.107	0.101	0.097	0.122	0.148	
GoB support (US$ millions):						
Budget support	0.0	3.1	14.8	7.7	6.2	
IDA support	0.6	3.1	0.0	0.0	0.0	
Total support	**0.6**	**6.2**	**14.8**	**7.7**	**6.2**	**35.4**
Alternative I						
Tariff increase	**0%**	**35%**	**5%**	**15%**	**0%**	**63%**
Av tariff (US$/kWh in nominal prices)	0.107	0.136	0.138	0.153	0.148	
GoB support (US$ millions):						
Budget support	0.0	3.1	8.7	1.5	0.0	
IDA support	0.6	3.1	0.0	0.0	0.0	
Total support	**0.6**	**6.2**	**8.7**	**1.5**	**0.0**	**17.0**
Higher/(lower) GoB support (US$ millions)	**0.0**	**0.0**	**(6.1)**	**(6.1)**	**(6.2)**	**(18.4)**
Alternative II						
Tariff increase	**0%**	**110%**	**-32%**	**10%**	**4%**	**63%**
Av tariff (US$/kWh in nominal prices)	0.107	0.212	0.139	0.147	0.148	
GoB support (US$ millions):						
Budget support	0.0	0.0	0.0	0.0	0.0	
IDA support	0.6	3.1	0.0	0.0	0.0	
Total support	**0.6**	**3.1**	**0.0**	**0.0**	**0.0**	**3.7**
Higher/(lower) GoB support (US$ millions)	**0.0**	**(3.1)**	**(14.8)**	**(7.7)**	**(6.2)**	**(31.8)**

Table 28: Alternative Electricity Tariff Scenarios &GoB Support 2013 to 2017

6.35 All of the above scenarios assume that the cumulative tariff adjustments will be the same as in the base case (i.e. 63%) over four years to 2017. The financial impact of the alternative tariff paths is shown above in terms of tariff adjustments that will be needed each year and the level of GoB support that will be required. The alternative scenarios are described below.

i) **Base Case:** Tariff increases of 30% in January 2016 and 25% in January 2017 with GoB support of US$35.4 million from 2013 to 2017. This is the recommended option.

ii) **Alternative I:**Government support is limited to the rental thermal only and REGIDESO would be expected to pay for fuel costs of the Bujumbura thermal plant. Under these circumstances, GoB support to 2017 would be reduced by US$18.4 million and tariff adjustments would have to be brought forward, with tariff increases of 35%, 5% and 15% will be required on January 1, 2014, 2015 and 2016 respectively.

iii) **Alternative II:**No budget support towards thermal costs other than IDA support in 2013. Under these circumstances, GoB support to 2017 would be reduced by US$31.8 million and tariff adjustments would have to be brought forward, with tariff increase of 110% in January 2014 followed by a reduction of 32% in January 2015 and increases of 10% and 4% in January 2016 and 2017 respectively. This scenario is clearly unsustainable.

Financial Impact of Kagunuzi Hydro IPP

6.36 REGIDESO’s generation expansion plan envisages the procurement of electricity from a private developer and operator (IPP) of a hydro power plant with an installed capacity of 8MW and an estimated annual energy output of between 44GWh to 50GWh. The developer’s proposals include the transfer of ownership to REGIDESO after 25 years and an indicative tariff of 0.226US$/kWh in Years 1 to 25. Capital investment costs of the plant are estimated at US$52 million (including interest during construction) and equivalent to US$6,500/MW installed.

6.37 The indicative tariff of 0.226US$/kWh is considered to be expensive and it is not the least cost option. The contract will place a significant financial burden on REGIDESO for the next 25 years. This will be take or pay contract and REGIDESO will be obliged to pay the monthly fixed costs as long as the declared capacity is available. The power purchase costs for this plant are estimated to amount to around US$10.7 million each year and US$371 million over 25 years.

6.38 It is recommended that the Government should not enter into this contract under the terms proposed by the developer. The Government should not consider this project in the context of shortages in power supply over the next few years, it is more important to take a long term view and consider the financial implications over the long term. It would be better to extend the term of the existing 10MW rental thermal to cover the supply deficits beyond April 2015 when the existing contract expires. The following table shows the financial impacts of two alternative scenarios which have been considered.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2015-2025
Base Case - WITH Kagunuzi from April 2016 & Rental Thermal up to April 2015												
Revenues												
Burundi revenues based on December 2012 tariffs	20.0	23.2	28.4	30.6	33.3	36.7	40.2	44.2	48.5	52.8	57.7	415.6
Costs												
PP costs of Kagunuzi over 25 years	0.0	(8.0)	(10.7)	(10.7)	(10.7)	(10.7)	(10.7)	(10.7)	(10.7)	(10.7)	(10.7)	(104.1)
Thermal costs with rental thermal up to April 2015	(9.7)	(8.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(17.9)
Net Revenues	10.3	7.0	17.8	19.9	22.6	26.0	29.5	33.5	37.9	42.1	47.1	293.6
Scenario I - WITHOUT Kagunuzi & Rental Thermal up to April 2015												
Revenues												
Burundi revenues based on December 2012 tariffs	20.0	20.5	27.5	30.6	33.3	36.7	40.2	44.2	48.5	52.8	57.7	412.0
Costs												
PP costs of Kagunuzi over 25 years	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal costs with rental thermal up to April 2015	(9.7)	(8.2)	(8.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(26.2)
Net Revenues	10.3	12.3	19.2	30.6	33.3	36.7	40.2	44.2	48.5	52.8	57.7	385.8
Impact compared with Base Case												
Net financial impact US$ millions - positive/(negative)	0.0	5.3	1.5	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	92.2
As % of Burundi revenues based on Dec 2012 tariffs	0.0%	23.0%	5.2%	34.9%	32.1%	29.1%	26.6%	24.2%	22.0%	20.2%	18.5%	22.2%
Scenario II - WITHOUT Kagunuzi & Rental Thermal up to April 2017												
Revenues												
Burundi revenues based on December 2012 tariffs	21.0	21.9	27.8	30.6	33.3	36.7	40.2	44.2	48.5	52.8	57.7	414.8
Costs												
PP costs of Kagunuzi over 25 years	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermal costs with rental thermal up to April 2017	(16.9)	(16.9)	(10.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(44.5)
Net Revenues	4.1	5.0	17.2	30.6	33.3	36.7	40.2	44.2	48.5	52.8	57.7	370.4
Impact compared with Base Case												
Net financial impact US$ millions - positive/(negative)	(6.1)	(2.0)	(0.6)	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	76.7
As % of Burundi revenues based on Dec 2012 tariffs	-30.7%	-8.5%	-2.0%	34.9%	32.1%	29.1%	26.6%	24.2%	22.0%	20.2%	18.5%	18.5%

Table 29: Financial Impacts of Kagunuzi Hydro IPP

6.39 As can be seen from the above table, it is financially more prudent to rely on the more expensive thermal power in the short term than to commit to a long term hydro supply contract that will involve in high fixed costs. The financial impact under Scenario I (without Kagunuzi and rental thermal contract not extended) is estimated to result in net additional revenues of US$92.2 million, equivalent to 22.2% of projected electricity revenues based on December 2012 tariffs. The financial impact under Scenario II (without Kagunuzi and rental thermal contract extended by two years to April 2017) is estimated to result in net additional revenues of US$76.7 million, equivalent to 18.5% of projected electricity revenues based on December 2012 tariffs. Scenario II is the recommended option as the additional capacity during the two years to April 2017 will be needed to meet the underlying domestic demand.

Cost of Service (CoS) and Revenues

6.40 The following chart showsthe projected cost of service,operating revenues and revenue surpluses/shortfalls over the forecast period. Electricity revenues are forecast on the basis of projected demand and tariffs. Totaloperating revenues are inclusive of GoB subsidies and the operating surpluses/shortfalls are after taking account of these subsidies.

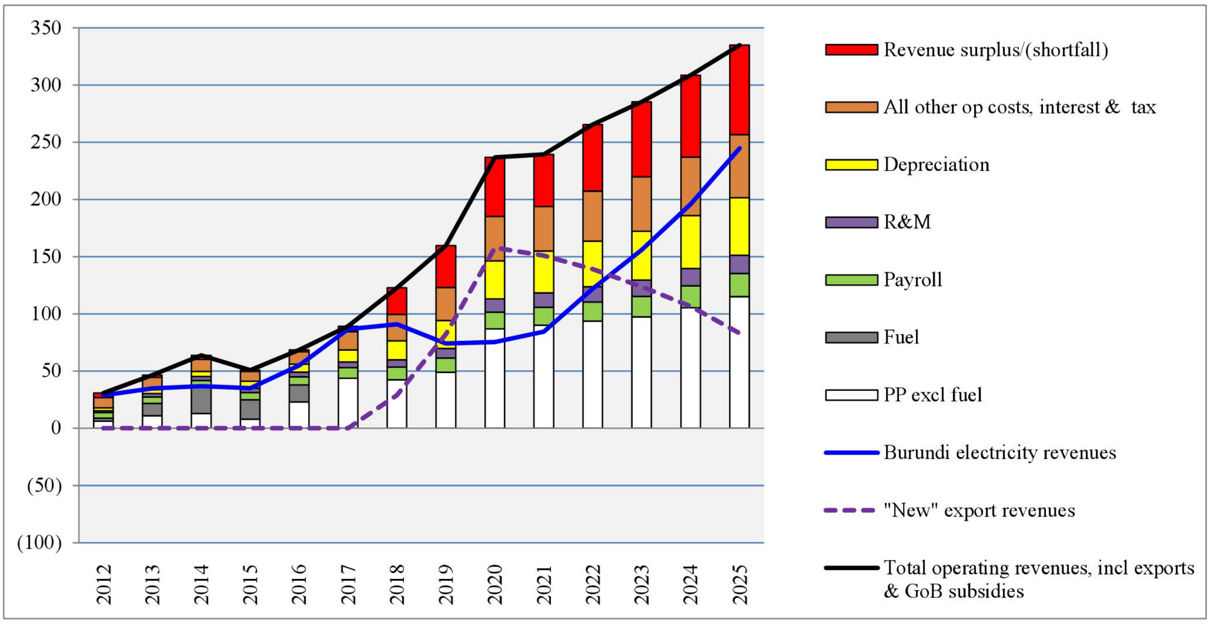

Chart 11: Electricity CoS vs. Operating Revenues, INCLUDING “New” Exports in FBU billions 2012-2025

6.41 As can be seen from the above chart, the projected operating revenues fully cover the cost of revenue throughout the forecast period. The cost of service from 2019 onwards can only be covered if the projected “new” exports and related export revenues are realized. Without such export revenues, the projected base case Burundi tariffs and revenues will not be adequate to cover the cost of revenue from 2019to 2023 as illustrated in the following chart. This means that revenues in those years will not fully cover depreciation charges and consequently Burundi tariffs will have to be either set at much higher levels from 2019 onwards or investments funded from internal resourceswill have to be curtailed.

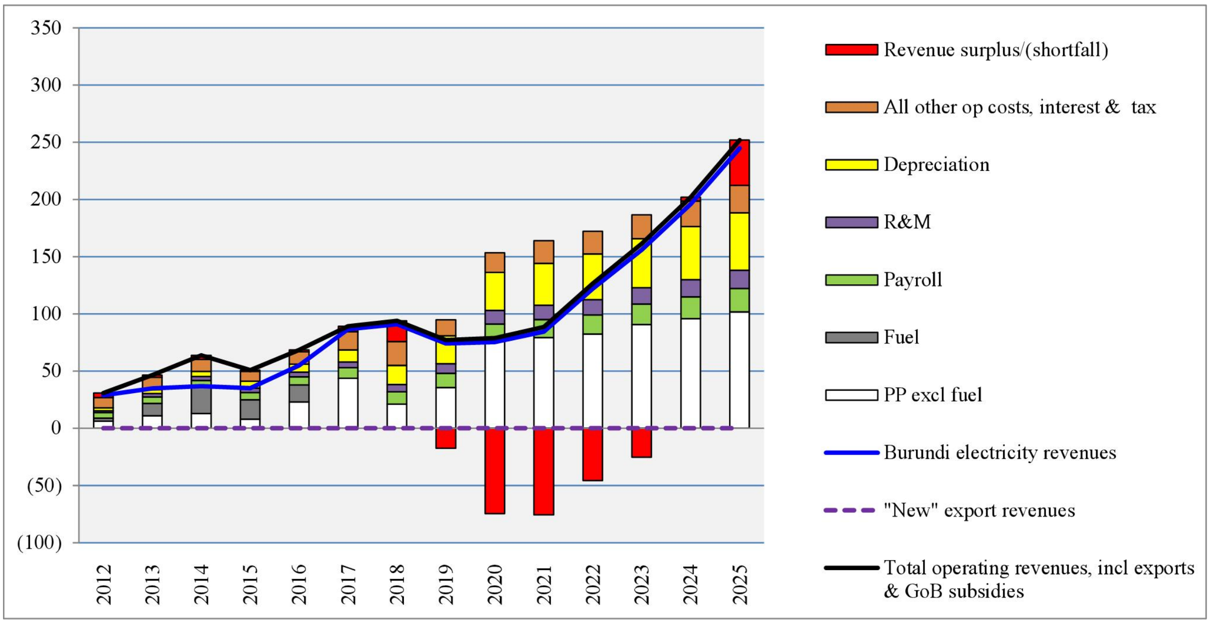

Chart 12: Electricity CoS vs. Operating Revenues, EXCLUDING “New” Exports in FBU billions 2012-2025

6.42 The make-up of REGIDESO's forecast operating expenses expressed as percentages of total operating revenues over the next thirteen years are illustrated in the following chart.

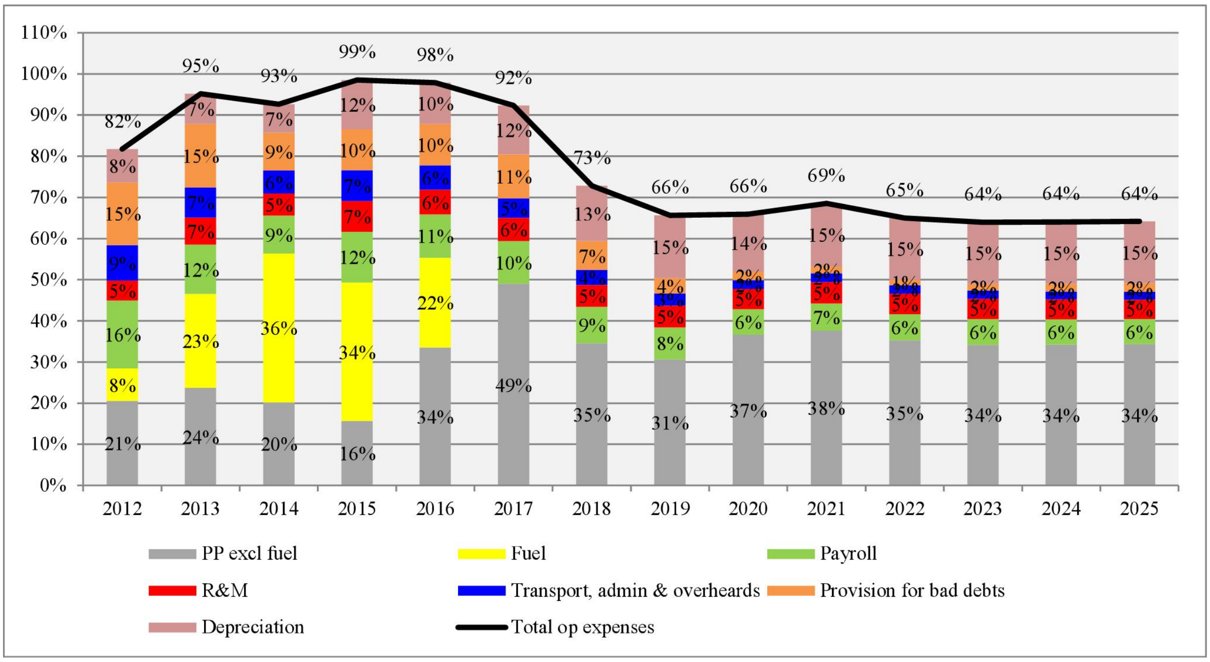

Chart 13: Electricity Operating Costs as % of Operating Revenues 2012 to 2025

6.43 In descending order, the components of operating expenses are made up of power purchase, fuel, depreciation (non-cash item), payroll, repairs & maintenance, bad debts and all other expenses. Increasing reliance on power purchases accounts for a growing share of total operating costs over the coming years. Expenditures on repairs & maintenance costs are expected to grow over the years due to the rapid expansion of the network and growth in customer numbers. Total operating expenses are forecast to range from 99% to 64% of total operating revenues.

6.44 The structure of REGIDESO's cash operating costs is going to change quite radically over the next few years. The split between fixed and variable costs in 2012 is estimated as 39% fixed and 61% variable. This is forecast to change to 78% fixed and 22% variable by 2025, primarily due to fixed capacity & fixed O&M costs of IPPs. The table below shows cash operating expenses split between fixed and variable costs over the forecast period. The cost differential between peak and other periods will thus narrow considerably over the next few years.

				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Power purchase excluding fuel																	
Capacity & fixed O&M costs	Fixed			0.0	2.3	3.2	0.0	8.0	10.7	10.7	18.0	37.8	38.3	38.8	39.4	40.0	40.6
Variable O&M costs	Variable			4.3	4.6	4.4	4.5	4.6	12.6	11.4	6.7	5.1	5.2	5.3	5.5	7.6	10.2
Generation fuel	Variable			1.7	6.6	13.6	9.7	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Payroll	Fixed	80.0%	<assumed	2.8	2.8	2.8	2.9	3.2	3.9	4.5	5.0	5.8	6.1	6.3	6.6	6.9	7.2
	Variable	20.0%	<assumed	0.7	0.7	0.7	0.7	0.8	1.0	1.1	1.3	1.5	1.5	1.6	1.6	1.7	1.8
Repairs & maintenance	Fixed	60.0%	<assumed	0.6	1.2	1.2	1.3	1.4	1.6	2.0	2.5	3.5	3.6	3.8	3.9	4.1	4.2
	Variable	40.0%	<assumed	0.4	0.8	0.8	0.9	0.9	1.1	1.3	1.7	2.3	2.4	2.5	2.6	2.7	2.8
Transport & travel	Fixed	70.0%	<assumed	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
	Variable	30.0%	<assumed	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Administration & overheads	Fixed	80.0%	<assumed	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6
	Variable	20.0%	<assumed	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Total operating expenses, excluding depreciation & bad debts				12.3	21.1	28.9	22.2	29.3	33.2	33.4	37.6	58.3	59.5	60.8	62.1	65.6	69.6
Total fixed	Fixed			39%	37%	31%	26%	49%	54%	57%	73%	84%	84%	84%	83%	81%	78%
Total variable	Variable			61%	63%	69%	74%	51%	46%	43%	27%	16%	16%	16%	17%	19%	22%

Table 30: Electricity Cash Operating Expenses Split between Fixed & Variable in US$ millions 2012 to 2025

6.45 The order of dispatch of power plants will primarily be dictated by costs of supply of individual plants. The guiding principles is to rank the power plants in terms of least cost and the recovery of fixed capacity and O&M charges of IPPs which have to be paid irrespective of energy output. Power purchase tariffs are indicated in the following table.

		COD	US$/kWh	
Emergency Power (Interpetrol)	Thermal	2013	0.4699	all inclusive tariff, including fuel. Contract from Apr 12, 2013 to Apr 11, 2015
Ruzizi I (DRC) - SNEL	Hydro	Existing	0.0780	in 2012 prices, escalated in line with US CPI. Ongoing contract
Ruzizi II (DRC) - SINELAC	Hydro	Existing	0.0337	equivalent to 0.022SDK/kWh in 2012 prices, escalated in line with US CPI. Ongoing contract
Kagunuzi IPP	Hydro	2016	0.2260	fixed, as per submissions of African Power & Water. Anticipated contract starting Apr 2016
Lac-Kivu (EWSA)	Methane	2017	0.2073	energy available for import from EWSA (estimated cost in 2017 prices)
Ruzizi III (DRC)	Hydro	2020	0.1090	as per latest estimates in Year prices, escalated thereafter in line with US CPI
Rusumo Falls (R,T & B)	Hydro	2019	0.0576	levelized tariff to 2025 as per latest estimates

Table 31: Power Purchase Tariffs in US$/kWh

6.46 In view of all of the above, the ideal order of plant dispatch would be:

i) REGIDESO owned hydros

ii) IPP owned hydros, including imports, with fixed costs

iii) IPP owned hydros, including imports, with no fixed costs

iv) Imports from EWSA's Methane plants, based on non-firm energy

v) Liquid fuel

6.47 The above order of dispatch is a general guide only. In reality, each plant would have to be considered in terms of its availability, cost structure and tariff.

Cash Flows

6.48 The cash flows of REGIDESO's electricity operationsover the forecast period will be healthy if (a) the projected tariff adjustments are implemented, (b) the assumed Government support towards thermal costs in 2013 to 2016 is extended to REGIDESO, (c) the anticipated efficiency improvements in network losses and billing collection are achieved, and (d) the projected funding for REGIDESO's investment plan is secured under the terms assumed in the base case analysis. The table and chart below show the summary cash flows in US$ millions to 2025.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
Cash flow from operations	(1.5)	1.9	3.7	1.6	3.6	3.5	22.6	31.3	47.2	36.7	49.9	52.5	55.0	57.8	367.2
Debt service paid	0.1	0.1	0.0	0.0	0.0	0.3	1.3	8.1	15.2	19.4	22.4	22.4	22.4	22.4	134.1
Investments funded from own resources less external funding	(2.4)	6.0	2.9	2.6	2.7	2.9	21.4	22.5	23.1	25.2	27.4	29.9	32.4	35.1	234.1
Net cash inflow/(outflow)	0.8	(4.2)	0.8	(1.0)	0.9	0.3	(0.1)	0.7	8.9	(7.9)	0.0	0.2	0.2	0.3	(1.0)
Cash balance at Dec 31	5.1	0.7	1.5	0.4	1.3	1.5	1.4	2.0	10.8	2.7	2.7	2.8	3.0	3.2	3.2

Table 32: Summary Cash Flows (Electricity) in US$ millions 2012 to 2025

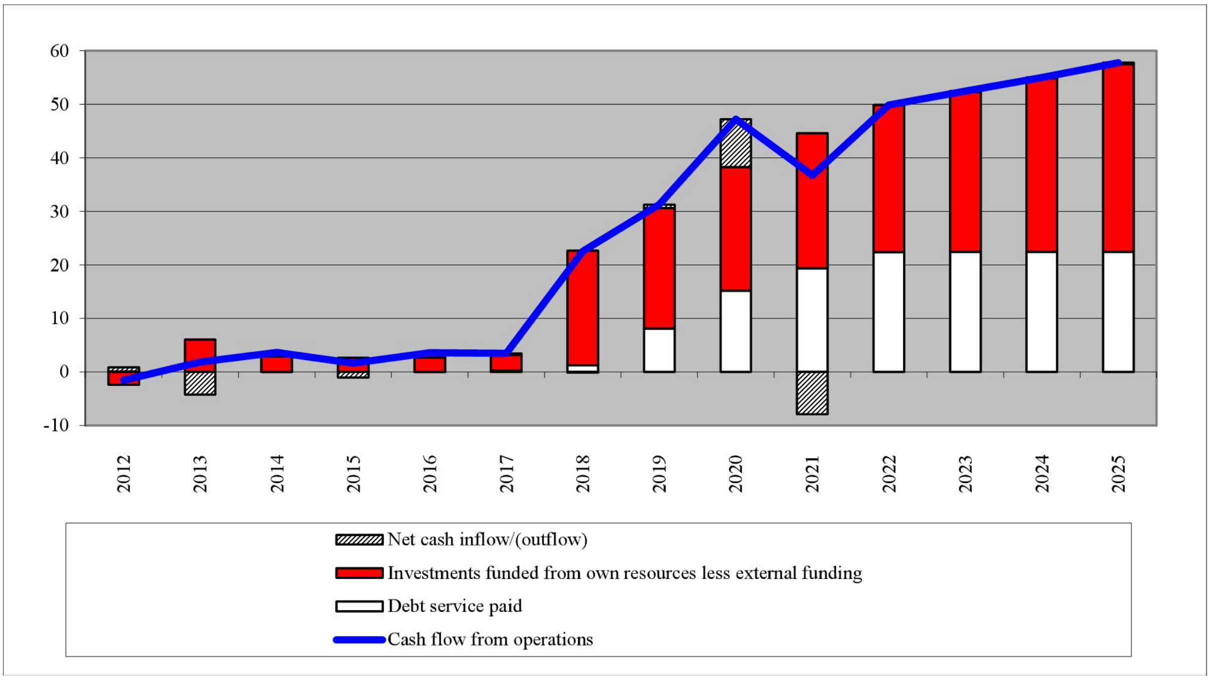

Chart 14: Summary Cash Flows (Electricity) in US$ millions 2012 to 2025

6.49 As can be seen clearly from the above table, REGIDESO will be in a position to meet its operational and other requirements from the projected revenues and Government support. The projected net cash outflows over the next thirteen years to 2025 are forecast at US$1 million, with positive cash balances throughout. Shortfalls in any particular year will be covered from surpluses of earlier years.

6.50 The debt service burden is forecast to increase dramatically over the next few years, as indicated in the above table and chart. Annual debt service requirements are expected to rise considerably from 2019 onwards as ongoing and new debt mature for debt service payments. The annual debt service payments are forecast to grow from US$1.3 million in 2018 to US$22.4 million from 2022 onwards.The make-up of debt service requirements over the coming years is shown in the following table. Funding for projects that show no debt service are assumed to be extended as grants.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
GoB funding	0.0	0.0	0.0	0.0	0.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	16.2
EXIMBANK of India (KABU 16)	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	42.0
Jiji & Mulembwe Development (WB/EIB/AfDB funded)	0.0	0.0	0.0	0.0	0.0	0.0	6.3	8.5	8.5	8.5	8.5	8.5	8.5	57.4
Ruzibazi	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	3.6	3.6	3.6	3.6	18.0
KITE 20 (Masango)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.6	2.6	2.6	12.9
PMIRE - 220kV TL - Kigoma-Gitega (EU/KfW funded)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMIRE - 220kV TL - Kamanyola-Bujumbura & Kigoma-Gitega (A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inter-connection Rusumo-Gitega (Burundi) (ADF Project)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMIEE - IDA Project SDR30.4 million	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PURSE - IDA Project US$15.4 millin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rehabilitation of HT lines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extension & Rehabilitation of Network - beyond 2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New customer connections	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest on late payments	0.06	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.3
Total debt service requirements	0.1	0.0	0.0	0.0	0.5	2.0	14.3	16.5	22.7	22.7	22.7	22.7	22.7	146.8
Opening less closing liabilities at balance sheet date	0.0	0.0	0.0	(0.0)	(0.3)	(0.7)	(6.2)	(1.3)	(3.3)	(0.3)	(0.3)	(0.2)	(0.2)	(12.7)
Total debt service paid	0.1	0.0	0.0	0.0	0.3	1.3	8.1	15.2	19.4	22.4	22.4	22.4	22.4	134.1

Table 33: Debt Service Requirements (Electricity) in US$ millions 2012 to 2025

Government Support to REGIDESO's Electricity Operations

6.51 The likely support required from the Governmentover the next thirteenyears to 2025 is going to be considerable. The projected financial support is indicated in the following table.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
Government subsidies towards thermal costs (i.e. tariff support)															
Budget support	0.0	5.0	25.0	13.5	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.7
IDA support	0.9	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
Total tariff support	0.9	9.9	25.0	13.5	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.6
Government & donor financing of investments															
GoR equity (including donor grants)	23.3	31.5	57.0	54.8	66.8	73.6	67.7	24.1	2.7	0.0	0.0	0.0	0.0	0.0	378.1
On-lent loans (donor funding)	0.0	13.5	33.7	108.5	155.5	173.2	119.5	60.5	10.8	0.0	0.0	0.0	0.0	0.0	675.0
Total Support for REGIDESO's Electricity Operations:															
In FBU billions	**24.2**	**54.9**	**115.6**	**176.8**	**233.5**	**246.7**	**187.2**	**84.6**	**13.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**1,112.7**
In US$ millions	**16.6**	**34.3**	**68.5**	**100.7**	**128.5**	**131.6**	**97.2**	**42.8**	**6.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**610.1**

Table 34: GoB Support for REGIDESO's Electricity Operations 2012 to 2025

6.52 Government support for REGIDESO's electricity operations over the period 2013 to 2025is estimated at FBU1,112 billion (US$610 million), including direct budget support of FBU54.7 billion (US$31.8 million) towards thermal costs. Government and donor funding of investments is estimated at FBU1,053 billion (US$575million). Financing for on-going investments is provided as per agreed or secured financing plan. New investments for which financing is not yet secured are assumed to be funded by a combination of Government contributions (i.e. equity) and borrowing, as detailed in Table 36 below.

Revenues Accruing to Government from REGIDESO's Electricity Operations

6.53 The estimated revenues accruing to the Government from REGIDESO's electricity operations over the period 2013 to 2025 are summarized in the following table.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
VAT on electricity bills:															
Based on present (March 2012) tariffs	5.2	6.3	6.6	6.3	7.6	9.6	10.6	11.8	13.4	13.4	15.0	16.9	19.0	21.1	157.6
Additional VAT on forecast higher tariffs	0.0	0.0	0.0	0.0	2.3	6.0	5.8	1.5	0.2	0.2	0.2	5.0	9.1	14.2	44.5
Total VAT	5.2	6.3	6.6	6.3	9.9	15.6	16.4	13.3	13.6	13.6	15.2	21.9	28.1	35.3	202.1
Corporate income tax	1.7	0.8	1.6	0.4	0.7	2.0	10.0	15.7	22.2	22.2	19.6	25.0	28.0	30.6	178.9
Fuel duties on liquid fuels used for generation	0.0	0.6	1.3	0.9	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Debt service on on-lent donor loans	0.0	0.0	0.0	0.0	0.0	0.5	2.4	16.0	30.8	30.8	40.2	47.6	48.7	49.7	266.6
Total Support for REGIDESO's Electricity Operations:															
In FBU billions	**6.9**	**7.8**	**9.6**	**7.7**	**11.4**	**18.1**	**28.7**	**45.0**	**66.5**	**66.5**	**75.0**	**94.5**	**104.8**	**115.6**	**651.3**
In US$ millions	**4.7**	**4.9**	**5.7**	**4.4**	**6.2**	**9.6**	**14.9**	**22.8**	**32.9**	**32.1**	**35.3**	**43.5**	**47.3**	**51.1**	**310.5**

Table 35: Revenues Accruing to GoB from REGIDESO's Electricity Operations 2012 to 2025

6.54 Total revenues accruing to the Government from REGIDESO's electricity operations over the period 2013 to 2025 are estimated at FBU651 billion (US$310 million). This compares to total GoB support of FBU1,112 billion (US$610 million) during the same period.

Principal Assumptions for the Financial Projections to 2025

6.55 Macroeconomic assumptions:The financial projections are prepared in current Burundi Francs (FBU), using the inflation and exchange rate forecasts below. The exchange rate of the Burundi Franc against the US dollar has been projected forward on the basis of inflation differential.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Burundi inflation	9.0%	5.9%	5.7%	5.5%	5.1%	5.1%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
International inflation	1.8%	1.7%	1.9%	2.0%	2.2%	2.3%	2.5%	2.5%	2.5%	2.5%	2.9%	2.9%	2.9%
Average exchange rate (FBU/US$)	1,601	1,689	1,755	1,818	1,874	1,927	1,977	2,025	2,074	2,125	2,173	2,218	2,265
Exchange rate at December 31 (FBU/US$)	1,655	1,723	1,787	1,848	1,900	1,953	2,000	2,049	2,099	2,150	2,195	2,241	2,288

Table 36: Macroeconomic Assumptions

6.56 Energy and Sales: The assumptions with regard to generation expansion, energy demand and network losses are indicated above and in Annex1.

6.57 Burundi Electricity Tariffs: The assumed Burundi retail electricity tariffs to 2025 are indicated above and in Annex1. Tariffs are set at levels to meet REGIDESO's revenue requirements for its electricity operations, net of assumed Government subsidies.

6.58 Government Subsidies: The assumed Government subsidies to REGIDESO towards the capacity and fuel costs of the emergency rental thermal plants are detailed above.

6.59 Export Tariffs: Export tariffs for "new" firm and non-firm exports (as assumed and detailed above) from 2018 to 2025 are assumed at 0.094US$/kWh and 0.117US$/kWh respectively (in 2012 prices), and escalated for US inflation, as forecast. The "firm" tariff represents the estimated average cost of supply of power purchase costs during the period (2017-25). The resultant average cost is grossed up for 4.5% transmission losses (assumed) and a 10% profit margin is added. The "non-firm" tariff is assumed at 1.25 times the "firm" tariff.

6.60 Projected Fuel Prices to 2025: The following table shows the fuel prices assumed in the base case projections. The underlying crude oil prices over the forecast period from 2013 to 2025 are based on the latest forecasts of the World Bank; price in 2012 is an estimate based on latest international prices. Fuel margins and all charges are assumed at current rates, and transport and other logistics costs to Bujumbura are based on current prices and escalated. Fuel duty and other Government imposed charges payable for liquid fuel are assumed at current rates of 105.6FBU/litre.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base Case - World Bank forecast	102.4	101.0	101.0	100.8	100.6	100.4	100.2	100.0	100.0	100.0	100.0	100.0	100.0

Table 37: Forecast Crude Oil Prices US$/barrel 2013 to 2025

6.61 Power Purchase Costs: The power purchase tariffs assumed in the base case financial projections are indicated in Table 28 above.

6.62 Power purchase tariffs are forecast on the basis of contracted tariffs for existing power supplies. For new supplies, as forecast, the tariffs are estimated on the basis of ongoing negotiations or latest available estimates.

6.63 Payroll Costs: The present numbers of staff employed by REGIDESO are identified by the company as working specifically for its water or electricity operations and for common services. Employees working for the common services are allocated to the electricity operations on the basis of direct staff working for the two operations. On this basis, the total number of employees working for the electricity operations in 2012 is assumed at 687. In addition to this staff strength, the following assumptions have been for future years: (a) the number of staff to be employed at new hydro power plants (Mpanda, KABU16, Jiji, Mulembwe, Ruzibazi and Masango) to be owned and operated by REGIDESO are assumed at the same levels (in terms of installed MW capacity) as currently employed at the existing hydro plants, and (b) for every 2,000 new customer connections, one new employee will be recruited each year. Payroll costs per employee are escalated in line with forecast Burundi inflation.

6.64 Repairs & Maintenance Costs: These costs are calculated as a percentage of opening gross value of REGIDESO owned fixed assets in service; the assumed percentages are 4% in 2013 (the actual rate in the 2010 to 2012 was 4.4%), 3.25% in 2014, 2.75% in 2015 and 2016, 1.75% in 2017, 1.25% in 2018 and 1% thereafter. The lower percentages are applied in later years in view of the significant additions to fixed assets.

6.65 Transport, Administration & Overhead Costs: Costs in 2013 are estimated as per REGIDESO budget. Thereafter, costs are escalated forward in line with forecast Burundi inflation.

6.66 Taxation:Provision is made for corporate income tax based on the present tax rate of 30% and applied to taxable income according to current legislation. Unutilised tax losses in any particular year are carried-forward and available for set-off against future profits. In case of tax losses in any particular year, corporate income tax is payable at the rate of 1% on electricity revenue. Corporate income tax is payable at the rate of 30% if the utility makes taxable profits. No provision is made for deferred taxation.

6.67 Fixed Assets and Work in Progress: Assets under construction are shown under work in progress in the balance sheet. The costs of assets are transferred from work in progress to fixed assets on their forecast commissioning dates. Fixed assets are stated at cost less depreciation. Interest financed during construction is capitalized.The following asset lives have been assumed for calculating depreciation charges over the forecast period. Depreciation is calculated on the opening gross value of fixed assets.

	Years
Assets acquired up to December 31, 2012	22.7
Subsequent additions:	
Hydro plants	45
Thermal plants	15
Transmission network	40
Distribution network	25
Buildings	50
Vehicles, Office F&F, Computers, etc	5

Table 38: Electricity Asset Lives in Years

6.68 Provision for Bad Debts and Accounts Receivable: Full provision is made for Burundi uncollected billings, inclusive of VAT. Billing collection rates are assumed to increase by 1.5% per annum, starting from the present estimated rate of 84.1% (actual average over the past three years 2010 to 2012) until they reach an optimum level of 97.5% in 2022. Receivables from electricity sales in Burundi are assumed at 65 days' annual collectable billing in 2013 (the actual at end 2012 was 182). Thereafter, the ratio is reduced to 60 days in 2014, 55 days in 2015, 50 days in 2016, and 45 days' thereafter (i.e. net of bad debts and inclusive of VAT). No provision for bad debts is made for export billings and receivables at the balance sheet date are assumed at 45 days' annul billing.Accounts receivables from Burundi customers as at December 31, 2012, as recorded in REGIDESO's books, are written-off to the extent that they are considered irrecoverable.

6.69 Accounts Payable:Accounts payable for all operational costs other than payroll costs are assumed at 100 days' annual costs, inclusive of VAT, in 2013 (the actual at end 2012was 183; however, the overdue debts due to SNEL and SINELAC are to be cleared by end 2013). Thereafter, the ratio is reduced to 60 days in 2014 to 2016,and 45 days' thereafter. Liability for VAT is assumed at 30 days' of net VAT payable on annual customer billing (output) less VAT recoverable (input tax) on annual operational costs other than payroll costs.

6.70 Inventory: Inventory at the balance sheet date is forecast at 15% of opening gross fixed assets in service at December 31, 2013, 12.5% at end 2014, 10% at end 2015 and 2016, 7% at end 2017, 4.5% at end 2018, 3.5% at end 2019, and at 2.5% at each balance sheet thereafter.

6.71 Customer Deposits: Customer deposits for new connections are escalated in line with assumed increases in electricity tariffs.

6.72 Government Contributions and Long-term Loans for Investments: Financing for on-going investments is provided as per agreed or secured financing plan. New investments for which financing is not yet secured are assumed to be funded by a combination of Government contributions (i.e. equity) and borrowing. The following financing assumptions have been made with respect to planned investments.

	Customer contributions	Borrowing	GoB/Donor Grant
Mpanda		80%	20%
KABU 16		100%	0%
Jiji		80%	20%
Mulembwe		80%	20%
Ruzibazi		80%	20%
KITE 20 (Masango)		80%	20%
Rehabilitation of Hydros (REGIDESO funded)		0%	0%
Bujumbura thermal plant (5MW)		0%	100%
PMIRE - 220kV TL - Kamanyola-Bujumbura (AfDB/KfW funded)		0%	100%
Inter-connection Rusumo-Gitega (Burundi) (ADF Project)		0%	100%
PMIEE - IDA Project SDR30.4 million		0%	100%
PURSE - IDA Project US$15.4 millin		0%	100%
110kV TL (80km) Jiji & Mulembwe Plants to Bujumbura South (WB funded)		80%	20%
Distribution Projects (REGIDESO funded)		0%	0%
Rural Electrification (REGIDESO funded)		0%	0%
Rehabilitation of HT lines		0%	0%
Extension & Rehabilitation of Network - beyond 2017		0%	0%
New customer connections			
Up to 2017	33%	0%	67%
Therafter	33%	0%	0%
Buildings, Vehicles, Office F&F, Computers, etc		0%	0%

Table 39: Financing of Investments

6.73 REGIDESO's investment budget for 2013 assumes that the costs of new connections will be fully funded by customers. The number of new connections in future years will have to be accelerated considerably in order to achieve the assumed electricity access rate of 15% by 2025 (the Government's target is to achieve 25% access rate by 2025). The accelerated connection program will therefore involve low income households who will not be able to afford the connections costs (assumed at US$400 in 2013 prices). The financial analysis therefore assumes that customer connection costs from 2014 to 2017 will be funded as follows: 33.3% by customers and 66.7% by the Government (to be extended as grant to REGIDESO). Thereafter, customers will contribute 33.3% and the balance will be funded by REGIDESO from its internal resources.

6.74 Borrowing for all projects in the future, which are to be on-lent from GoB (i.e. GoB funding and donor loans to GoB and on-lent to REGIDESO), are provided according to the terms detailed in the following table. It is assumed that all new loans will be on-lent in US dollars.

	Loan currency	Facility	Interest rate	Grace period (Years)	Repayment period excl grace (Years)	First repayment	Last repayment
GoB funding	USD	33.7	1.50%	5.00	20.00	2018	2038
EXIMBANK of India (KABU 16)	USD	80.0	1.50%	5.00	15.00	2019	2034
Jiji & Mulembwe Development (WB/EIB/AfDB funded)	USD	146.1	1.50%	5.00	20.00	2019	2039
Ruzibazi	USD	61.9	1.50%	5.00	20.00	2021	2041
KITE 20 (Masango)	USD	44.3	1.50%	5.00	20.00	2021	2041
Extension & Rehabilitation of Network - beyond 2017	USD	0.0	1.50%	5.00	15.00	2023	2038

Table 40: Investment Borrowing Terms

6.75 It is further assumed that interest accruing during project construction will be added to loan principal and repaid with loan principal. Interest during construction (IDC) is taken to work in progress and capitalized to fixed assets on project commissioning.

Sensitivity Analysis to the Base Case Projections

6.76 The following sensitivity analysis was conducted on the base case forecasts presented above, and the results are shown in the table below. Each of the sensitivities is considered in isolation, all other assumptions in the base case remaining unchanged.

	2013-2025		
	Increase/(decrease) in base case revenue shortfalls before tariff support		Tariff Impact (based on Dec 12 av tariff)
	FBU billions	US$ millions	
Downside Risks			
1. No GoB subsidies for thermal costs from 2013 (other than IDA support in 2013)	54.7	31.8	8.2%
2. No tariff increases throuhout the forecast period	345.2	161.7	51.5%
3. Payroll, repairs & maintenance, transport and administration & overhead costs 10% higher throughout the forecast period	23.8	11.8	2.6%
4. Power purchase costs (excluding fuel) are 10% higher	55.0	26.6	5.9%
5. All fuel costs are 10% higher	4.9	2.9	0.5%
6. Constant crude oil price at $115/bbl	4.2	2.4	0.5%
7. Overall T&D losses for Burundi supply to remain constant throughout at 2012 level of 19.9% (i.e. no efficiency improvements)	11.0	5.2	2.1%
8. Overall Burundi billing collection rate to remain constant throughout at actual average over last 3 years (2010-12) of 84.1% (i.e. no efficiency improvements)	47.1	22.6	5.1%
9. High demand forecast	59.9	28.4	2.9%
10. No "new" exports	608.6	289.5	65.3%
11. Export tariffs for "new" exports kept constant at 2012 prices (i.e. no escalation)	116.1	54.6	12.5%
Upside Potential			
12. Payroll, repairs & maintenance, transport and administration & overhead costs 10% lower throughout the forecast period	(23.8)	(11.8)	-2.6%
13. Distribution losses from 2014 reduced by 0.5% each year instead of 0.25%	(10.8)	(5.1)	-2.0%
14. Improvement in billing collection rate by 2% each year instead of 1.5%, until it reaches an optimum level of 97.5%	(5.2)	(2.7)	-0.6%
15. Low demand forecast	(52.7)	(25.3)	-2.4%
16. Constant crude oil price at $90/bbl	(3.2)	(1.8)	-0.3%

Table 41: Results of Sensitivity Analysis (Electricity Operations)

6.77 Most of the above sensitivities have a significant impact on REGIDESO's revenue requirements. The impacts of the sensitivities are commented upon below.

i) Sensitivity 1: The absence of GoB tariff support in 2013 to 2016 has a significant impact on revenues. The loss of FBU54.7 billion (US$31.8 million) over the forecast period to 2025 is equivalent to 8.2% impact on December 2102 Burundi average tariff.

ii) Sensitivity 2: If tariffs were kept constant at present levels, the overall collected revenues to 2025 would be FBU345.2 billion (US$161.7 million) lower, equivalent to 51.5% impact on December 2012 Burundi average tariff. This is clearly unsustainable.

iii) Sensitivity 3& 12: An increase or decrease of 10% in payroll, repairs & maintenance, transport and administration & overhead costs will impact on forecast cash flows by FBU23.8 billion (US$11.8 million) over the forecast period to 2025, equivalent to 2.6% impact on December 2012Burundi average tariff. These impacts are significant and illustrate the need to keep such costs under strict control.

iv) Sensitivity 4: An increase of 10% in power purchase costs over the forecast period will add FBU55.0 billion (US$26.6 million) to revenue requirements over the forecast period, equivalent to 5.9% impact on December 2012Burundi average tariff.

v) Sensitivity 5: An increase of 10% in fuel costs over the forecast period will add FBU4.2 billion (US$2.4 million) to revenue requirements to 2025, equivalent to 0.5% impact on December 2012Burundi average tariff. The fuel costs only arise during the four years to 2016 and the tariff impact over these years is much higher at 3.3%.

vi) Sensitivities 6 &16: If crude oil prices were assumed at a constant US$115/barrel, instead of around US$100/barrel from 2013, the additional revenue requirements would amount to FBU4.2 billion (US$2.4 million) over four years to 2016, equivalent to 2.8% impact on December 2012 Burundi average tariff over the four years or 0.5% over the entire forecast period to 2025. Similarly, if the crude oil prices were assumed at a constant US$90/barrel, the revenue requirements would reduce by FBU3.2 billion (US$1.8 million)over four years to 2015, equivalent to 2.1% impact on December 2012 Burundi average tariff over the four years or 0.3% over the entire forecast period to 2025.There is no impact beyond 2016as no thermal generation is projected from then on.

vii) Sensitivities7& 13: The impact of network losses is significant. If the overall network losses for Burundi supply were to remain constant (i.e. no efficiency improvements) throughout the forecast period at the present level of 19.9%, the revenue requirements over the forecast period would increase by FBU11.0 billion (US$5.2 million), equivalent to 2.1% impact on December 2012 average Burundi tariff. On the other hand, an accelerated reduction in distribution losses of 0.5% annually (instead of 0.25%), will result in savings in revenue requirements of FBU10.8 billion (US$5.1 million), equivalent to 2.0% impact on December 2012Burundi average tariff. The revenue impacts illustrate the importance of achieving efficiency improvements.

viii) Sensitivities 8 & 14: If the present Burundi billing collection rate was to remain constant (i.e. no efficiency improvements) throughout the forecast period at the present estimated level of 84.1%, the shortfall in revenue requirements over the forecast period would increase by FBU47.1 billion (US$22.6 million), equivalent to 5.1% impact on December 2012Burundi average tariff. On the other hand, an accelerated improvement in billing collection of 2.0% annually (instead of 1.5%), will result in additional cash inflows of FBU5.2 billion (US$2.7 million), equivalent to 0.6% impact on December 2012 Burundi average tariff. The revenue impacts illustrate the importance of achieving efficiency improvements.

ix) Sensitivities 9& 15: High demand in Burundi, as forecast, over the forecast period would increase the shortfalls in revenue requirements by FBU59.9 billion (US$28.4 million), equivalent to 2.9% impact on December 2012 Burundi average tariff. On the other hand, low demand in Burundi, as forecast, over the forecast period will result in revenue requirements of FBU52.7 billion (US$25.3 million), equivalent to 2.4% impact on December 2012 average tariff.

x) Sensitivity10: The base case assumes that capacity or energy surplus to domestic requirements will be exported on “firm” and “non-firm” basis. These assumptions are critical to the financial viability of REGIDESO if the planned generation expansion is implemented. Net cash inflows arising from such exports account for FBU608.6 billion (US$289.5 million) in export revenues, equivalent to 65.3% impact on December 2012Burundi average tariff.

xi) Sensitivity 11: The likely tariff for the new exports will significantly impact on REGIDESO’s revenues. If the assumed export tariffs were kept constant at 2012 prices and not escalated for US inflation, the loss in revenues would amount to FBU116.1 billion (US$54.6 million), equivalent to 12.5% impact on December 2012Burundi average tariff.

Government Contingent Liabilities

6.78 The developers of the anticipated Kagunuzi hydro IPP in Burundi and in the regional hydro development projects will enter into long-term (typically 15 to 25 years) power purchase agreements (PPA) with REGIDESO as the off-taker. However, these developers will require Government guarantees for the recovery of their fixed capacity (i.e. investment or capital) and fixed operations & maintenance costs covering the period of the PPA’s. Such fixed power purchase costs will rise sharply over the coming years in line with increasing reliance on energy supplies from these sources. The total annual fixed costs are forecast to increase from US$2.3 million in 2013 to US$81.7 million from 2020 onwards. The following table shows the projected installed capacities of IPPs as available to REGIDESO and the annual fixed charges (capacity payments and fixed O&M costs) payable to IPPs to 2025. Total fixed charges of IPPs are estimated to amount to US$287.6 millionover thirteen years from 2013 to 2025.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2013-25
Installed MW Capacity of IPPs as available to REGIDESO														US$ mln
Emergency thermal (Interpetrol)	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Kagunuzi (private)	0.0	0.0	0.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Ruzizi III (DRC)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	47.0	47.0	47.0	47.0	47.0	
Rusumo Falls (B, R &T)	0.0	0.0	0.0	0.0	0.0	0.0	26.7	26.7	26.7	26.7	26.7	26.7	26.7	
Total installed MW capacities of IPPs	10.0	10.0	0.0	8.0	8.0	8.0	34.7	81.7	81.7	81.7	81.7	81.7	81.7	
Fixed Charges of IPP's in US$ millions														
Emergency thermal (Interpetrol)	2.3	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5
Kagunuzi (private)	0.0	0.0	0.0	8.0	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	104.1
Ruzizi III (DRC)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8	20.3	20.8	21.4	22.0	22.6	126.8
Rusumo Falls (B, R &T)	0.0	0.0	0.0	0.0	0.0	0.0	7.3	7.3	7.3	7.3	7.3	7.3	7.3	51.2
Total fixed charges in US$ millions	2.3	3.2	0.0	8.0	10.7	10.7	18.0	37.8	38.3	38.8	39.4	40.0	40.6	287.6

Table 42: Installed MW Capacities & Fixed Charges of IPPs (US$ millions) 2013 to 2025

7 REGIDESO Electricity Operations Compared

7.1 REGIDESO’s size and performance with respect to its electricity operations is compared in some key respects with those of Rwanda (EWSA, electricity operations), Uganda power sector (UEGCL, UETCL, UEDCL & Umeme combined), Kenya (KPLC) and Tanzania (TANESCO) in the following table.

	Burundi		Rwanda		Uganda		Kenya		Tanzania		Burundi relative to			
	Year to Dec 2012 Forecast		Year to June 2012 Actual		Year to Dec 2011 Est Actual		Year to June 2012 Actual		Year to Dec 2011 Estimate		Rwanda	Uganda	Kenya	Tanzania
Energy Sent Out (GWh):														
Hydro	137	56%	172	38%	1,534	59%	3,450	45%	1,977	38%				
Thermal	3	1%	195	43%	958	37%	2,671	35%	3,144	60%				
Geo thermal	0	0%	0	0%	0	0%	1,498	20%	0	0%				
Renewables	0.0	0%	0.3	0%	60	2%	15	0%	17	0%				
Imports	104	43%	88	19%	39	1%	36	0%	62	1%				
Total sent out	243	100%	456	100%	2,591	100%	7,670	100%	5,200	100%	53%	9%	3%	5%
Peak demand (MW)	54		84		455		1,236		830		65%	12%	4%	7%
Sales, including small exports (GWh)	195		369		1,838		6,341		4,000		53%	11%	3%	5%
Life-line monthly consumption band	0-50kWh		None		0-15kWh		0-50kWh		0-50kWh					
No. of customers at year-end ('000s)	76		297		450		1,656		923		26%	17%	5%	8%
No. of new connections ('000s)	9.3		95		56		212		73		9.8%	16.7%	4.4%	12.7%
Av. no. of customers per employee	101		232		267		139		153		44%	38%	73%	66%
T&D losses (%)	19.9%		18.9%		29.1%		17.3%		23.1%		105%	69%	115%	86%
Av crude oil price during the year (OPEC FOB) US$/bbl	109.45		110.11		107.46		110.11		107.46		99%	102%	99%	102%
Power purchase & fuel costs (US$ millions)	6.0		54		321		735		350		11%	2%	1%	2%
Bulk supply costs (US$/kWh sent out)	0.025		0.118		0.124		0.096		0.067		21%	20%	26%	37%
Bulk supply costs (US$/kWh sold)	0.031		0.146		0.175		0.116		0.088		21%	18%	27%	35%
Retail tariff US$/kWh sold														
Actual	0.102		0.182		0.112		0.184		0.09		56%	91%	55%	118%
Required (unsubsidised)	0.092		0.263		0.251		0.184		0.13		35%	36%	50%	70%
Shortfall (= Subsidy)	-11.1%		30.7%		55.4%		0.0%		34.3%					
Gross margin based on actual tariffs	69.7%		19.8%		-55.6%		37.0%		-1.3%		352%	-125%	188%	-5188%
Exrate to US$ (average during period)	1,454		609		2,523		87		1,578					
Tariff Increases implemented subsequent to year end														
Overall % increase			0.0%		55.5% <Jan 12				40.3% < Jan 12					
New retail tariff US$/kWh sold			0.182		0.176				0.119		56%	58%	55%	86%

Table 43: Burundi Power Sector Compared with Rwanda, Uganda, Kenya and Tanzania

7.2 The above table compares the actual statistics of Burundi for the year ending December 31, 2012 against those of EWSA (year ending to June 30, 2012), Uganda (2011), Kenya (year ending June 30, 2012) and Tanzania (2011). KPLC's figures are actuals. Uganda's figures are estimated actuals and are subject to revision. TANESCO's figures are broad estimates and the actual figures may be very different.

7.3 In terms of its size, Burundi power sector is the second smallest in the region – it is 53% of the size of Rwanda, 9% of Uganda, 3% of Kenya and 5% of Tanzania. Hydro power, including hydro based imports, accounted for 99% of total supply, compared with Rwanda's 57%, Uganda's 59%, Kenya's 45% and Tanzania's 38%. REGIDESO had 76,000 active customers at December 31, 2012, being 26% of EWSA, 17% of Uganda, 5% of Kenya and 8% of Tanzania. The average number of customers per employee of 101for REGIDESO's electricity operations does not compare well against 232 for Rwanda (electricity operations), 267 for Uganda power sector as a whole, 139 for Kenya (KenGen and KPLC combined) and 153 for TANESCO. However, it should be noted that Umeme (the private operator of Uganda's distribution network) outsources some of its activities and third party employees involved in these activities are not reflected in Uganda's statistics.

7.4 Burundi's T&D losses of 19.9% were the second lowest. Kenya was the lowest with 17.3% and Uganda highest with 29.1%. Tanzania's losses were 23.1%. The average bulk supply costs of Burundi were the lowest at 0.025US$/kWh sent out. Uganda had the highest costs at 0.124US$/kWh against 0.118 in Rwanda, 0.096 in Kenya and 0.067 in Tanzania. The added costs of land transportation for oil supplies to Burundi, Rwanda and Uganda place them at a disadvantage compared with Kenya and Tanzania. The average retail tariffs in Rwanda and Kenya were the highest at around 0.18US$/kWh, compared with 0.102 in Burundi (second lowest), 0.09 in Tanzania (lowest), 0.112 in Uganda. The crucial difference and the bottom line result is the difference between the actual average end-user tariffs and revenue requirements of the utilities. Burundi had a surplus margin of 11.1% against shortfalls (or subsidies provided by Government) in Rwanda 30.7%, Uganda 55.4% and Tanzania's 34.3%. It is assumed that Kenya's tariffs were fully cost reflective.

7.5 REGIDESO's tariffs were revised in September 2011 and March 2012 (previous increase was in May 2007), resulting in an overall cumulative increase of 69% in the weighted average tariff.

7.6 EWSA's tariffs were last revised in July 2012 (first since 2006).TANESCO's electricity tariffs were increased on average by 40.3% effective January 15, 2012 (TANESCO had applied for 156% on the basis of "firm" hydro energy output. The regulator disputed this, amongst other assumptions, and amended the assumptions on hydro output to "average" energy). TANESCO had previously adjusted its tariffs by an average of 18.5% effective January 1, 2011; the tariffs were unchanged since January 2008.

7.7 Electricity tariffs to end-use customers in Uganda were increased on average by 55.5% effective January 15, 2012. The tariffs were previously adjusted on January 1, 2010 which led to an overall decrease of 7.9% of the weighted average tariff. Previous to this the tariffs were unchanged since November 1, 2006. Uganda's latest tariffs are still not fully cost reflective; the average tariff after the increase in January 2012 is estimated at 0.176US$/kWh. In March 2012, the regulator proposed the implementation of an automatic tariff adjustment mechanism (to take account of exchange rate movements, changes in fuel prices and inflation).The proposal is going through a consultative process.

7.8 Kenya's end-user tariffs are revised regularly to account for the effects of power purchase costs, fuel prices, inflation and exchange rate fluctuations.

7.9 After the implementation of the latest tariff increases, REGIDESO's new average tariff of 0.11US$/kWh will be the lowest. Rwanda and Kenya's weighted average tariffs of around 0.18US$/kWh will be close to those of Uganda (0.176US$/kWh), compared with TANESCO's 0.119US$/kWh.Thermal costs of TANESCO are much lower than those of its neighbors as its generation mix includes 49% of the much lower cost gas fired output.

ANNEX 1: REGIDESO Electricity Operational & Financial Indicators 2010-2025

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Target	Actual	Actual	Actual	Forecast												
Operational indicators																	
Peak demand Burundi (MW)		50	52	54	57	63	69	77	85	94	104	118	132	148	166	184	204
Energy sent out (GWh)																	
Burundi		238	242	243	256	268	255	306	386	425	473	533	596	670	750	831	925
Exports		0	0	0	0	0	0	0	0	120	324	600	539	473	401	328	244
Burundi + Exports		238	242	243	256	268	255	306	386	546	798	1,133	1,136	1,143	1,151	1,159	1,168
of which:																	
Hydro (REGIDESO)		52%	52%	56%	51%	47%	49%	48%	53%	68%	62%	57%	57%	57%	56%	56%	55%
Hydro (Purchase)		41%	43%	43%	41%	36%	38%	43%	37%	26%	37%	43%	43%	43%	44%	44%	43%
AGO (Purchase)		3%	2%	0%	5%	7%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Growth in sent out (Burundi)		15.3%	1.7%	0.4%	5.2%	4.9%	-5.0%	20.1%	25.9%	10.3%	11.2%	12.7%	11.8%	12.3%	12.0%	10.7%	11.3%
T&D losses (%)																	
Burundi	13.2%	20.7%	17.8%	19.9%	19.9%	19.7%	19.5%	19.2%	19.0%	18.7%	18.5%	18.3%	18.0%	17.8%	17.6%	17.3%	17.1%
Burundi + Exports		20.7%	17.8%	19.9%	19.9%	19.7%	19.5%	19.2%	19.0%	15.7%	13.0%	11.2%	11.8%	12.5%	13.2%	13.8%	14.6%
Electricity sales (GWh)																	
Burundi		189	199	195	205	216	205	247	312	346	386	436	489	550	618	687	767
Exports		0	0	0	0	0	0	0	0	114	308	570	512	450	381	312	232
Total REGIDESO		189	199	195	205	216	205	247	312	460	694	1,006	1,001	1,000	999	999	998
Growth in electricity sales																	
Burundi		14.1%	5.4%	-2.3%	5.2%	5.2%	-4.7%	20.4%	26.3%	10.6%	11.5%	13.1%	12.1%	12.6%	12.4%	11.1%	11.6%
Burundi + Exports		14.1%	5.4%	-2.3%	5.2%	5.2%	-4.7%	20.4%	26.3%	47.2%	50.9%	44.9%	-0.4%	-0.1%	-0.1%	0.0%	0.0%
No. of new customer connections		4,797	6,713	9,307	7,636	8,000	9,000	11,000	14,000	18,000	23,000	28,000	33,000	38,000	43,000	48,000	53,000
Av. no. of customers		57,429	63,184	71,194	79,665	87,483	95,983	105,983	118,483	134,483	154,983	180,483	210,983	246,483	286,983	332,483	382,983
of which customers with prepayment meters		22%	37%	45%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Av. no. of employees		718	722	704	689	693	697	729	842	982	1,086	1,206	1,286	1,304	1,324	1,347	1,372
Av. no. of customers per employee		80	88	101	116	126	138	145	141	137	143	150	164	189	217	247	279
Electricty sales (MWh) per employee		263	276	277	298	311	295	340	371	468	639	834	778	767	755	742	728
Financial indicators																	
Average revenue, expenses & profit																	
Av. electricity revenue (FBU/kWh)																	
Burundi		101	110	148	171	171	171	222	277	263	192	173	173	221	252	285	319
Exports		0	0	0	0	0	0	0	0	254	267	277	295	309	325	342	359
Overall REGIDESO		101	110	148	171	171	171	222	277	261	226	232	235	261	280	303	329
Av. electricity revenue (US$/kWh)																	
Burundi		0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.137	0.097	0.085	0.083	0.104	0.116	0.129	0.141
Exports		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.132	0.135	0.137	0.142	0.146	0.150	0.154	0.158
Overall REGIDESO		0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.135	0.114	0.115	0.113	0.123	0.129	0.137	0.145
Av. Other op revenue, incl Govt subsidies (FBU/kWh)		50	65	13	68	159	92	61	9	11	16	20	23	21	21	21	22
Av. Other op revenue, incl Govt subsidies (US$/kWh)		0.040	0.050	0.009	0.043	0.094	0.052	0.034	0.005	0.006	0.008	0.010	0.011	0.010	0.010	0.010	0.010
Av. operating expenses (FBU/kWh)																	
Power purchase excluding fuel		30	44	32	54	60	39	93	140	92	70	86	90	94	98	106	115
Generation fuel		21	22	12	52	107	83	60	0	0	0	0	0	0	0	0	0
Payroll		24	24	26	27	27	31	29	30	24	18	15	16	17	18	19	20
Repairs & maintenance		11	15	8	15	16	18	17	16	14	12	12	13	13	14	15	16
Transport, administration & overheads		16	14	14	17	17	18	16	13	10	7	5	5	5	6	6	6
Total cash operating expenses		101	120	92	165	227	189	215	199	140	107	117	123	129	135	146	158
Depreciation		10	9	13	17	20	30	28	34	36	35	33	37	40	43	46	50
Provisions for bad debts & stock obsolescence		2	1	24	35	27	24	28	31	19	9	5	4	4	5	6	7
Total operating expenses		113	129	129	216	274	243	271	264	195	151	155	164	173	183	198	215
Av. operating expenses (US$/kWh)																	
Power purchase excluding fuel		0.024	0.034	0.022	0.034	0.035	0.022	0.051	0.075	0.048	0.036	0.043	0.043	0.044	0.045	0.048	0.051
Generation fuel		0.017	0.017	0.009	0.032	0.063	0.047	0.033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Payroll		0.019	0.019	0.018	0.017	0.016	0.017	0.016	0.016	0.012	0.009	0.007	0.008	0.008	0.008	0.009	0.009
Repairs & maintenance		0.009	0.011	0.005	0.009	0.009	0.011	0.009	0.009	0.007	0.006	0.006	0.006	0.006	0.007	0.007	0.007
Transport, administration & overheads		0.013	0.011	0.009	0.010	0.010	0.010	0.009	0.007	0.005	0.003	0.002	0.002	0.003	0.003	0.003	0.003
Total cash operating expenses		0.082	0.092	0.063	0.103	0.134	0.108	0.118	0.106	0.073	0.054	0.058	0.059	0.061	0.062	0.066	0.070
Depreciation		0.008	0.007	0.009	0.010	0.012	0.017	0.015	0.018	0.019	0.018	0.016	0.018	0.019	0.020	0.021	0.022
Provisions for bad debts & stock obsolescence		0.002	0.001	0.017	0.022	0.016	0.014	0.015	0.016	0.010	0.004	0.002	0.002	0.002	0.002	0.003	0.003
Total operating expenses		0.092	0.100	0.089	0.135	0.162	0.139	0.149	0.141	0.101	0.076	0.077	0.079	0.081	0.084	0.089	0.095
Av. operating profit/(loss) (FBU/kWh)		15	16	29	11	22	4	6	22	73	79	80	75	93	103	111	120
Av. operating profit/(loss) (US$/kWh)		0.012	0.013	0.020	0.007	0.013	0.002	0.003	0.012	0.038	0.040	0.040	0.036	0.044	0.047	0.050	0.053
Profitability																	
Operating margin (%)		11.6%	11.2%	18.3%	4.8%	7.4%	1.5%	2.2%	7.7%	27.2%	34.3%	34.1%	31.5%	35.0%	36.0%	35.9%	35.8%
Return on equity (%)		7.7%	5.0%	5.0%	2.0%	2.6%	0.5%	0.6%	1.4%	5.5%	7.4%	9.3%	7.6%	8.9%	9.1%	9.1%	9.1%
Billing & collection performance (Burundi)																	
Av. collection period (days)	45	227	187	182	65	60	55	50	45	45	45	45	45	45	45	45	45
Av. billing collection rate (%)	97.5%	92%	96%	78%	84%	86%	87%	89%	90%	92%	93%	95%	96%	98%	98%	98%	98%
Overall Performance (Burundi)																	
1. Energy collected/energy sent out (Burundi)	97.5%	72.8%	78.8%	62.4%	67.3%	68.7%	70.1%	71.5%	73.0%	74.4%	75.8%	77.3%	78.7%	80.1%	80.4%	80.6%	80.8%
2. Revenue collected/energy sent out (Burundi) (FBU/kWh)		17	16	24	27	27	27	34	43	40	29	26	26	32	37	41	45
3. Weighted average revenue (Burundi) (FBU/kWh)		101	110	148	171	171	171	222	277	263	192	173	173	221	252	285	319
4. Overall Performance Index (2/3)		0.164	0.146	0.160	0.160	0.158	0.157	0.155	0.154	0.152	0.151	0.149	0.148	0.146	0.145	0.143	0.142
Cash generation																	
Net cash inflow/(outflow)																	
FBU million		(428)	2,270	1,108	(6,714)	1,268	(1,775)	1,580	585	(209)	1,323	18,073	(16,340)	93	393	411	636
US$ million		(0.3)	1.8	0.8	(4.2)	0.8	(1.0)	0.9	0.3	(0.1)	0.7	8.9	(7.9)	0.0	0.2	0.2	0.3
Self-financing ratio (%)		9.1%	25.8%	-3.3%	14.8%	6.6%	3.7%	4.1%	3.3%	17.2%	22.9%	69.8%	61.8%	91.5%	95.8%	96.8%	102.6%
Debt service cover (times)		90.3	23.4	50.2	55.0	327.9	271.0	303.0	16.2	10.7	2.3	2.8	2.0	2.3	2.4	2.5	2.7
Liquidity																	
Current ratio (times)	1.1 minimum	2.6	1.9	3.2	1.9	2.2	2.9	2.6	2.6	0.9	0.7	0.8	0.7	0.7	0.7	0.8	0.8
Gearing																	
Debt/equity ratio (%)	80% maximum	17%	17%	13%	23%	29%	45%	54%	59%	59%	58%	56%	53%	51%	48%	45%	42%

ANNEX 2: REGIDESO Pro-Forma Income Statements (Elec) in FBU mlns 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Electricity sales (GWh)																
Burundi	189	199	195	205	216	205	247	312	346	386	436	489	550	618	687	767
Exports	0	0	0	0	0	0	0	0	114	308	570	512	450	381	312	232
Total sales	189	199	195	205	216	205	247	312	460	694	1,006	1,001	1,000	999	999	998
Average electricity revenue (FBU/kWh)																
Burundi	101	110	148	171	171	171	222	277	263	192	173	173	221	252	285	319
Exports	0	0	0	0	0	0	0	0	254	267	277	295	309	325	342	359
Overall REGIDESO	101	110	148	171	171	171	222	277	261	226	232	235	261	280	303	329
Average electricity revenue (US$/kWh)																
Burundi	0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.137	0.097	0.085	0.083	0.104	0.116	0.129	0.141
Exports	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.132	0.135	0.137	0.142	0.146	0.150	0.154	0.158
Overall REGIDESO	0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.135	0.114	0.115	0.113	0.123	0.129	0.137	0.145
Operating revenue																
Electricity revenue																
Burundi	19,090	21,878	28,838	34,960	36,764	35,045	54,856	86,586	91,009	74,093	75,395	84,541	121,884	156,112	195,924	244,914
Exports	0	0	0	0	0	0	0	0	29,009	82,376	157,888	150,950	139,086	123,876	106,525	83,078
Total electricity revenue	19,090	21,878	28,838	34,960	36,764	35,045	54,856	86,586	120,018	156,469	233,283	235,491	260,970	279,988	302,449	327,992
Other operating revenue	731	498	1,004	1,724	2,095	2,242	2,406	2,598	2,837	3,138	3,523	3,998	4,571	5,252	6,050	6,976
Government subsidies & amortization of grants	4,298	6,679	869	9,925	24,993	13,458	11,204	0	0	0	0	0	0	0	0	0
Total operating revenue	24,119	29,055	30,711	46,608	63,852	50,745	68,466	89,183	122,855	159,607	236,805	239,488	265,541	285,240	308,499	334,968
Operating expenses																
Power purchase excluding fuel	5,602	8,850	6,313	11,069	12,906	7,951	22,954	43,713	42,509	48,888	86,745	90,150	93,701	97,438	105,472	114,992
Generation fuel	3,995	4,310	2,423	10,637	23,050	17,055	14,939	0	0	0	0	0	0	0	0	0
Payroll	4,453	4,869	5,065	5,553	5,913	6,289	7,193	9,237	10,876	12,477	14,760	15,699	16,726	17,849	19,079	20,423
Repairs & maintenance	2,023	2,946	1,499	3,111	3,404	3,797	4,137	5,055	6,492	8,369	11,699	12,560	13,334	14,129	15,011	15,956
Transport & travel	636	780	350	890	942	996	1,050	1,104	1,160	1,218	1,279	1,343	1,410	1,481	1,555	1,632
Administration & overheads	2,383	2,102	2,287	2,493	2,640	2,789	2,943	3,092	3,250	3,412	3,583	3,762	3,950	4,148	4,355	4,573
Operating expenses before depreciation & provisions	19,093	23,858	17,937	33,753	48,855	38,877	53,216	62,202	64,287	74,364	118,067	123,513	129,121	135,045	145,472	157,577
Depreciation	1,835	1,796	2,482	3,423	4,391	6,085	6,833	10,569	16,510	24,407	33,169	36,542	39,842	42,869	46,385	50,178
Provisions for bad debts & stock obsolescence	400	153	4,679	7,184	5,903	5,024	6,935	9,566	8,652	6,016	4,913	4,034	3,626	4,609	5,747	7,136
Total operating expenses	21,328	25,807	25,098	44,360	59,149	49,985	66,984	82,337	89,449	104,787	156,148	164,089	172,589	182,523	197,604	214,892
Operating profit/(loss)	2,791	3,248	5,612	2,247	4,703	759	1,483	6,847	33,405	54,820	80,657	75,399	92,952	102,717	110,895	120,076
Non-operating income - net	971	262	238	259	274	290	306	321	338	355	372	391	411	431	453	475
Net finance charges																
Net interest payable/(receivable)	(170)	(45)	(249)	(324)	(424)	(448)	(473)	475	477	2,865	7,159	10,344	10,027	9,661	9,248	8,804
Exchange (gains)/losses	167	482	666	0	0	0	0	0	0	0	0	0	0	0	0	0
Net finance charges	(3)	437	417	(324)	(424)	(448)	(473)	475	477	2,865	7,159	10,344	10,027	9,661	9,248	8,804
Profit/(loss) before taxation	3,765	3,073	5,433	2,831	5,401	1,497	2,262	6,693	33,266	52,309	73,871	65,446	83,336	93,487	102,100	111,748
Taxation	255	298	1,672	849	1,620	449	678	2,008	9,980	15,693	22,161	19,634	25,001	28,046	30,630	33,524
Profit/(loss) after taxation	3,510	2,775	3,761	1,982	3,781	1,048	1,583	4,685	23,287	36,617	51,710	45,813	58,335	65,441	71,470	78,224
Av. operating profit/(loss) (FBU/kWh)	15	16	29	11	22	4	6	22	73	79	80	75	93	103	111	120
Av. operating profit/(loss) (US$/kWh)	0.012	0.013	0.020	0.007	0.013	0.002	0.003	0.012	0.038	0.040	0.040	0.036	0.044	0.047	0.050	0.053
Operating margin (%)	11.6%	11.2%	18.3%	4.8%	7.4%	1.5%	2.2%	7.7%	27.2%	34.3%	34.1%	31.5%	35.0%	36.0%	35.9%	35.8%
Return on equity (%)	7.7%	5.0%	5.0%	2.0%	2.6%	0.5%	0.6%	1.4%	5.5%	7.4%	9.3%	7.6%	8.9%	9.1%	9.1%	9.1%

ANNEX 3: REGIDESO Pro-Forma Income Statements (Elec) in US$ mlns 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Electricity sales (GWh)																
Burundi	189	199	195	205	216	205	247	312	346	386	436	489	550	618	687	767
Exports	0	0	0	0	0	0	0	0	114	308	570	512	450	381	312	232
Total sales	189	199	195	205	216	205	247	312	460	694	1,006	1,001	1,000	999	999	998
Average electricity revenue (FBU/kWh)																
Burundi	101	110	148	171	171	171	222	277	263	192	173	173	221	252	285	319
Exports	0	0	0	0	0	0	0	0	254	267	277	295	309	325	342	359
Overall REGIDESO	101	110	148	171	171	171	222	277	261	226	232	235	261	280	303	329
Average electricity revenue (US$/kWh)																
Burundi	0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.137	0.097	0.085	0.083	0.104	0.116	0.129	0.141
Exports	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.132	0.135	0.137	0.142	0.146	0.150	0.154	0.158
Overall REGIDESO	0.082	0.085	0.102	0.107	0.101	0.097	0.122	0.148	0.135	0.114	0.115	0.113	0.123	0.129	0.137	0.145
Operating revenue																
Electricity revenue																
Burundi	15.5	16.9	19.8	21.8	21.8	20.0	30.2	46.2	47.2	37.5	37.2	40.8	57.4	71.8	88.3	108.1
Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1	41.7	78.0	72.8	65.5	57.0	48.0	36.7
Total electricity revenue	15.5	16.9	19.8	21.8	21.8	20.0	30.2	46.2	62.3	79.2	115.2	113.5	122.8	128.9	136.3	144.8
Other operating revenue	0.6	0.4	0.7	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.7	1.9	2.2	2.4	2.7	3.1
Government subsidies & amortization of grants	3.5	5.1	0.6	6.2	14.8	7.7	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total operating revenue	19.6	22.4	21.1	29.1	37.8	28.9	37.7	47.6	63.8	80.7	116.9	115.5	125.0	131.3	139.1	147.9
Operating expenses																
Power purchase excluding fuel	4.5	6.8	4.3	6.9	7.6	4.5	12.6	23.3	22.1	24.7	42.8	43.5	44.1	44.8	47.5	50.8
Generation fuel	3.2	3.3	1.7	6.6	13.6	9.7	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Payroll	3.6	3.8	3.5	3.5	3.5	3.6	4.0	4.9	5.6	6.3	7.3	7.6	7.9	8.2	8.6	9.0
Repairs & maintenance	1.6	2.3	1.0	1.9	2.0	2.2	2.3	2.7	3.4	4.2	5.8	6.1	6.3	6.5	6.8	7.0
Transport & travel	0.5	0.6	0.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Administration & overheads	1.9	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0
Operating expenses before depreciation & provisions	15.5	18.4	12.3	21.1	28.9	22.2	29.3	33.2	33.4	37.6	58.3	59.5	60.8	62.1	65.6	69.6
Depreciation	1.5	1.4	1.7	2.1	2.6	3.5	3.8	5.6	8.6	12.3	16.4	17.6	18.8	19.7	20.9	22.2
Provisions for bad debts & stock obsolescence	0.3	0.1	3.2	4.5	3.5	2.9	3.8	5.1	4.5	3.0	2.4	1.9	1.7	2.1	2.6	3.2
Total operating expenses	17.3	19.9	17.3	27.7	35.0	28.5	36.9	43.9	46.4	53.0	77.1	79.1	81.2	84.0	89.1	94.9
Operating profit/(loss)	2.3	2.5	3.9	1.4	2.8	0.4	0.8	3.7	17.3	27.7	39.8	36.3	43.7	47.3	50.0	53.0
Non-operating income - net	0.8	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Net finance charges																
Net interest payable/(receivable)	(0.1)	(0.0)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	0.3	0.2	1.4	3.5	5.0	4.7	4.4	4.2	3.9
Exchange (gains)/losses	0.1	0.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net finance charges	(0.0)	0.3	0.3	(0.2)	(0.3)	(0.3)	(0.3)	0.3	0.2	1.4	3.5	5.0	4.7	4.4	4.2	3.9
Profit/(loss) before taxation	3.1	2.4	3.7	1.8	3.2	0.9	1.2	3.6	17.3	26.5	36.5	31.6	39.2	43.0	46.0	49.3
Taxation	0.2	0.2	1.1	0.5	1.0	0.3	0.4	1.1	5.2	7.9	10.9	9.5	11.8	12.9	13.8	14.8
Profit/(loss) after taxation	2.8	2.1	2.6	1.2	2.2	0.6	0.9	2.5	12.1	18.5	25.5	22.1	27.5	30.1	32.2	34.5
Av. operating profit/(loss) (FBU/kWh)	15	16	29	11	22	4	6	22	73	79	80	75	93	103	111	120
Av. operating profit/(loss) (US$/kWh)	0.012	0.013	0.020	0.007	0.013	0.002	0.003	0.012	0.038	0.040	0.040	0.036	0.044	0.047	0.050	0.053
Operating margin (%)	11.6%	11.2%	18.3%	4.8%	7.4%	1.5%	2.2%	7.7%	27.2%	34.3%	34.1%	31.5%	35.0%	36.0%	35.9%	35.8%
Return on equity (%)	7.7%	5.0%	5.0%	2.0%	2.6%	0.5%	0.6%	1.4%	5.5%	7.4%	9.3%	7.6%	8.9%	9.1%	9.1%	9.1%

ANNEX 4: REGIDESO Pro-Forma Balance Sheets (Elec) in FBU mlns 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Fixed & other Long-Term Assets																
Tangible assets at cost/valuation	63,352	85,445	106,481	168,372	267,302	442,022	682,788	954,580	1,211,172	1,370,243	1,459,725	1,540,191	1,626,026	1,718,939	1,820,982	1,932,889
Less: Accumulated depreciation	23,753	25,549	28,032	31,455	35,846	41,930	48,763	59,332	75,842	100,249	133,418	169,960	207,301	248,414	292,947	341,178
Net book value of fixed assets	39,599	59,896	78,449	136,918	231,456	400,092	634,025	895,248	1,135,330	1,269,994	1,326,307	1,370,231	1,418,725	1,470,525	1,528,035	1,591,711
Investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total long-term assets	39,599	59,896	78,449	136,918	231,456	400,092	634,025	895,248	1,135,330	1,269,994	1,326,307	1,370,231	1,418,725	1,470,525	1,528,035	1,591,711
Current assets																
Stocks	14,662	9,479	12,841	11,667	13,091	13,809	15,043	20,220	23,373	29,291	29,248	31,401	33,335	35,323	37,528	39,891
Customer accounts receivable	12,614	13,555	15,940	6,753	5,755	5,098	7,362	10,700	11,589	13,540	20,707	31,629	36,045	39,311	42,906	47,446
Other debtors & prepayments	342	385	395	431	456	482	509	535	562	590	619	650	683	717	753	791
Investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash at bank and in hand	4,574	6,844	7,952	1,238	2,507	731	2,311	2,896	2,687	4,010	22,083	5,743	5,837	6,230	6,640	7,276
Total current assets	32,191	30,264	37,129	20,089	21,809	20,120	25,226	34,351	38,210	47,430	72,658	69,423	75,900	81,580	87,828	95,403
Current liabilities (amounts falling due within one year)																
Creditors	12,283	15,908	11,531	9,691	8,376	6,405	8,946	7,725	7,937	9,134	14,742	15,582	16,592	17,639	19,309	21,256
Corporate tax payable	219	0	0	849	1,620	449	678	2,008	9,980	15,693	22,161	19,634	25,001	28,046	30,630	33,524
Bank overdraft	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debt service due	0	0	0	0	0	0	0	486	1,892	14,113	16,672	23,497	24,071	24,615	25,130	25,655
Current Portion of Long-Term Loans	0	0	0	0	0	0	0	2,786	24,813	25,611	36,046	37,479	38,902	40,311	41,771	41,771
Total current liabilities	12,502	15,908	11,531	10,540	9,997	6,854	9,625	13,004	44,622	64,551	89,622	96,193	104,566	110,611	116,840	122,206
Net current assets/(liabilities)	19,690	14,356	25,598	9,549	11,812	13,266	15,601	21,346	(6,412)	(17,121)	(16,964)	(26,769)	(28,666)	(29,031)	(29,013)	(26,803)
Total assets less current liabilities	59,289	74,252	104,047	146,466	243,268	413,358	649,626	916,594	1,128,918	1,252,873	1,309,343	1,343,461	1,390,059	1,441,493	1,499,022	1,564,907
Creditors (amounts falling due after more than one year)																
Long-term loans	0	0	0	13,958	49,079	162,176	328,326	517,217	656,764	715,515	721,101	702,208	681,404	656,344	629,336	600,288
Less: Current portion	0	0	0	0	0	0	0	(2,786)	(24,813)	(25,611)	(36,046)	(37,479)	(38,902)	(40,311)	(41,771)	(41,771)
Long-term portion	0	0	0	13,958	49,079	162,176	328,326	514,431	631,951	689,905	685,055	664,729	642,502	616,032	587,564	558,517
Customer deposits	409	522	563	602	643	689	762	878	1,019	1,152	1,296	1,467	1,719	2,043	2,453	2,959
Customer capital contributions (connection charges)	9,851	12,301	13,422	19,554	20,415	21,542	23,205	25,702	29,356	34,534	41,310	49,772	60,010	72,148	86,265	102,469
Total creditors (amounts falling due after more than one year)	10,259	12,823	13,985	34,115	70,136	184,406	352,293	541,011	662,327	725,591	727,662	715,968	704,231	690,224	676,282	663,944
Net assets employed	49,029	61,429	90,062	112,352	173,132	228,952	297,333	375,583	466,591	527,282	581,681	627,494	685,829	751,270	822,740	900,963
Capital and reserves																
Capital & reserves	34,037	26,741	32,073	22,901	26,682	27,730	29,313	33,998	57,285	93,901	145,611	191,423	249,759	315,200	386,669	464,893
Grants & Government contribution for investments	14,993	34,688	57,989	89,451	146,450	201,222	268,020	341,585	409,306	433,381	436,070	436,070	436,070	436,070	436,070	436,070
Shareholders' equity	49,029	61,429	90,062	112,352	173,132	228,952	297,333	375,583	466,591	527,282	581,681	627,494	685,829	751,270	822,740	900,963
Current ratio (times)	2.6	1.9	3.2	1.9	2.2	2.9	2.6	2.6	0.9	0.7	0.8	0.7	0.7	0.7	0.8	0.8
Debt/equity ratio	17%	17%	13%	23%	29%	45%	54%	59%	59%	58%	56%	53%	51%	48%	45%	42%

ANNEX 5: REGIDESO Pro-Forma Balance Sheets (Elec) in US$ mlns 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Fixed & other Long-Term Assets																
Tangible assets at cost/valuation	51.4	62.8	68.9	101.7	155.1	247.3	369.4	502.4	620.2	685.0	712.3	733.7	756.1	783.0	812.5	844.7
Less: Accumulated depreciation	19.3	18.8	18.1	19.0	20.8	23.5	26.4	31.2	38.8	50.1	65.1	81.0	96.4	113.2	130.7	149.1
Net book value of fixed assets	32.1	44.0	50.7	82.7	134.3	223.9	343.1	471.1	581.4	634.8	647.2	652.7	659.7	669.8	681.8	695.6
Investments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total long-term assets	32.1	44.0	50.7	82.7	134.3	223.9	343.1	471.1	581.4	634.8	647.2	652.7	659.7	669.8	681.8	695.6
Current assets																
Stocks	11.9	7.0	8.3	7.0	7.6	7.7	8.1	10.6	12.0	14.6	14.3	15.0	15.5	16.1	16.7	17.4
Customer accounts receivable	10.2	10.0	10.3	4.1	3.3	2.9	4.0	5.6	5.9	6.8	10.1	15.1	16.8	17.9	19.1	20.7
Other debtors & prepayments	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Investments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash at bank and in hand	3.7	5.0	5.1	0.7	1.5	0.4	1.3	1.5	1.4	2.0	10.8	2.7	2.7	2.8	3.0	3.2
Total current assets	26.1	22.2	24.0	12.1	12.7	11.3	13.6	18.1	19.6	23.7	35.5	33.1	35.3	37.2	39.2	41.7
Current liabilities (amounts falling due within one year)																
Creditors	10.0	11.7	7.5	5.9	4.9	3.6	4.8	4.1	4.1	4.6	7.2	7.4	7.7	8.0	8.6	9.3
Corporate tax payable	0.2	0.0	0.0	0.5	0.9	0.3	0.4	1.1	5.1	7.8	10.8	9.4	11.6	12.8	13.7	14.7
Bank overdraft	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Debt service due	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.0	7.1	8.1	11.2	11.2	11.2	11.2	11.2
Current Portion of Long-Term Loans	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	12.7	12.8	17.6	17.9	18.1	18.4	18.6	18.3
Total current liabilities	10.1	11.7	7.5	6.4	5.8	3.8	5.2	6.8	22.8	32.3	43.7	45.8	48.6	50.4	52.1	53.4
Net current assets/(liabilities)	16.0	10.5	16.6	5.8	6.9	7.4	8.4	11.2	(3.3)	(8.6)	(8.3)	(12.8)	(13.3)	(13.2)	(12.9)	(11.7)
Total assets less current liabilities	48.1	54.5	67.3	88.5	141.2	231.3	351.5	482.4	578.1	626.3	638.9	640.0	646.4	656.6	668.8	683.9
Creditors (amounts falling due after more than one year)																
Long-term loans	0.0	0.0	0.0	8.4	28.5	90.7	177.7	272.2	336.3	357.7	351.9	334.5	316.9	299.0	280.8	262.3
Less: Current portion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.5)	(12.7)	(12.8)	(17.6)	(17.9)	(18.1)	(18.4)	(18.6)	(18.3)
Long-term portion	0.0	0.0	0.0	8.4	28.5	90.7	177.7	270.7	323.6	344.9	334.3	316.7	298.8	280.6	262.2	244.1
Customer deposits	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8	0.9	1.1	1.3
Customer capital contributions (connection charges)	8.0	9.0	8.7	11.8	11.8	12.1	12.6	13.5	15.0	17.3	20.2	23.7	27.9	32.9	38.5	44.8
Total creditors (amounts falling due after more than one year)	8.3	9.4	9.0	20.6	40.7	103.2	190.6	284.7	339.2	362.7	355.1	341.1	327.5	314.4	301.7	290.2
Net assets employed	39.8	45.1	58.3	67.9	100.5	128.1	160.9	197.7	238.9	263.6	283.8	298.9	318.9	342.2	367.1	393.8
Capital and reserves																
Capital & reserves	27.6	19.6	20.7	13.8	15.5	15.5	15.9	17.9	29.3	46.9	71.1	91.2	116.1	143.6	172.5	203.2
Grants & Government contribution for investments	12.2	25.5	37.5	54.0	85.0	112.6	145.0	179.8	209.6	216.6	212.8	207.7	202.8	198.6	194.6	190.6
Shareholders' equity	39.8	45.1	58.3	67.9	100.5	128.1	160.9	197.7	238.9	263.6	283.8	298.9	318.9	342.2	367.1	393.8
Current ratio (times)	2.6	1.9	3.2	1.9	2.2	2.9	2.6	2.6	0.9	0.7	0.8	0.7	0.7	0.7	0.8	0.8
Debt/equity ratio	17%	17%	13%	23%	29%	45%	54%	59%	59%	58%	56%	53%	51%	48%	45%	42%

ANNEX 6: REGIDESO Pro-Forma Cash Flows (Elec) in FBU millions 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Net cash inflow/(outflow) from operating activities:																
Operating profit/(loss)	2,791	3,248	5,612	2,247	4,703	759	1,483	6,847	33,405	54,820	80,657	75,399	92,952	102,717	110,895	120,076
Non-operating income/(expense) - net	971	262	238	259	274	290	306	321	338	355	372	391	411	431	453	475
Depreciation	1,835	1,796	2,482	3,423	4,391	6,085	6,833	10,569	16,510	24,407	33,169	36,542	39,842	42,869	46,385	50,178
Customer capital contributions (connection charges) taken to income	(455)	(40)	(31)	(663)	(972)	(1,055)	(1,155)	(1,283)	(1,455)	(1,687)	(1,999)	(2,398)	(2,891)	(3,488)	(4,198)	(5,031)
(Increase)/decrease in working capital	(6,153)	(2,949)	(9,229)	(2,668)	(1,766)	(2,058)	(984)	(9,762)	(3,857)	(6,699)	(1,547)	(12,265)	(5,373)	(4,241)	(4,166)	(4,994)
Net cash inflow/(outflow) from operating activities	(1,011)	2,318	(928)	2,599	6,630	4,020	6,483	6,692	44,942	71,195	110,653	97,669	124,940	138,289	149,368	160,706
Net cash outflow for returns on investments and servicing of finance	170	45	249	324	424	448	473	11	(463)	(1,658)	(4,998)	(8,737)	(10,170)	(9,828)	(9,438)	(9,008)
Taxation paid	(255)	(298)	(1,672)	0	(849)	(1,620)	(449)	(678)	(2,008)	(9,980)	(15,693)	(22,161)	(19,634)	(25,001)	(28,046)	(30,630)
Investing activities:																
Payments to acquire tangible fixed assets	(11,188)	(22,092)	(21,036)	(61,431)	(97,466)	(170,148)	(230,108)	(256,055)	(233,710)	(135,986)	(69,043)	(63,312)	(71,661)	(80,827)	(90,591)	(101,131)
Receipts from disposals of tangible fixed assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net cash outflow from investing activities	(11,188)	(22,092)	(21,036)	(61,431)	(97,466)	(170,148)	(230,108)	(256,055)	(233,710)	(135,986)	(69,043)	(63,312)	(71,661)	(80,827)	(90,591)	(101,131)
Net cash inflow/(outflow) before financing	(12,283)	(20,028)	(23,387)	(58,508)	(91,261)	(167,301)	(223,602)	(250,030)	(191,238)	(76,428)	20,919	3,459	23,475	22,633	21,293	19,937
Financing activities:																
Grants & Government contribution for investments	9,605	19,695	23,301	31,462	56,999	54,772	66,798	73,565	67,722	24,075	2,689	0	0	0	0	0
Customer deposits & capital contributions (connection charges)	2,250	2,604	1,193	6,834	1,873	2,228	2,891	3,896	5,250	6,997	8,920	11,030	13,381	15,951	18,725	21,741
Borrowing	0	0	0	13,498	33,657	108,525	155,493	173,154	119,450	60,479	10,757	0	0	0	0	0
Borrowing repaid	0	0	0	0	0	0	0	0	(1,393)	(13,799)	(25,212)	(30,829)	(36,763)	(38,191)	(39,607)	(41,041)
Receipts/(payments) for investments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net cash inflow from financing activities	11,856	22,299	24,494	51,794	92,529	165,525	225,182	250,615	191,029	77,751	(2,846)	(19,799)	(23,382)	(22,240)	(20,882)	(19,301)
Increase/(decrease) in cash and cash equivalents	(428)	2,270	1,108	(6,714)	1,268	(1,775)	1,580	585	(209)	1,323	18,073	(16,340)	93	393	411	636
Cash and cash equivalents at beginning of year	5,001	4,574	6,844	7,952	1,238	2,507	731	2,311	2,896	2,687	4,010	22,083	5,743	5,837	6,230	6,640
Exchange difference	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash and cash equivalents at end of year	4,574	6,844	7,952	1,238	2,507	731	2,311	2,896	2,687	4,010	22,083	5,743	5,837	6,230	6,640	7,276
Self-financing ratio (%)	9.1%	25.8%	-3.3%	14.8%	6.6%	3.7%	4.1%	3.3%	17.2%	22.9%	69.8%	61.8%	91.5%	95.8%	96.8%	102.6%
Debt service cover (times)	90.3	23.4	50.2	55.0	327.9	271.0	303.0	16.2	10.7	2.3	2.8	2.0	2.3	2.4	2.5	2.7

ANNEX 7: REGIDESO Pro-Forma Cash Flows (Elec) in US$ millions 2010-2025

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Actual	Actual	Actual	Forecast												
Net cash inflow/(outflow) from operating activities:																
Operating profit/(loss)	2.3	2.5	3.9	1.4	2.8	0.4	0.8	3.7	17.3	27.7	39.8	36.3	43.7	47.3	50.0	53.0
Non-operating income/(expense) - net	0.8	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Depreciation	1.5	1.4	1.7	2.1	2.6	3.5	3.8	5.6	8.6	12.3	16.4	17.6	18.8	19.7	20.9	22.2
Customer capital contributions (connection charges) taken to income	(0.4)	(0.0)	(0.0)	(0.4)	(0.6)	(0.6)	(0.6)	(0.7)	(0.8)	(0.9)	(1.0)	(1.2)	(1.4)	(1.6)	(1.9)	(2.2)
(Increase)/decrease in working capital	(5.0)	(2.3)	(6.3)	(1.7)	(1.0)	(1.2)	(0.5)	(5.2)	(2.0)	(3.4)	(0.8)	(5.9)	(2.5)	(2.0)	(1.9)	(2.2)
Net cash inflow/(outflow) from operating activities	(0.8)	1.8	(0.6)	1.6	3.9	2.3	3.6	3.6	23.3	36.0	54.6	47.1	58.8	63.6	67.3	71.0
Net cash outflow for returns on investments and servicing of finance	0.1	0.0	0.2	0.2	0.3	0.3	0.3	0.0	(0.2)	(0.8)	(2.5)	(4.2)	(4.8)	(4.5)	(4.3)	(4.0)
Taxation paid	(0.2)	(0.2)	(1.1)	0.0	(0.5)	(0.9)	(0.2)	(0.4)	(1.0)	(5.0)	(7.8)	(10.7)	(9.2)	(11.5)	(12.6)	(13.5)
Investing activities:																
Payments to acquire tangible fixed assets	(9.1)	(17.0)	(14.5)	(38.4)	(57.7)	(96.9)	(126.6)	(136.6)	(121.3)	(68.8)	(34.1)	(30.5)	(33.7)	(37.2)	(40.8)	(44.7)
Receipts from disposals of tangible fixed assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net cash outflow from investing activities	(9.1)	(17.0)	(14.5)	(38.4)	(57.7)	(96.9)	(126.6)	(136.6)	(121.3)	(68.8)	(34.1)	(30.5)	(33.7)	(37.2)	(40.8)	(44.7)
Net cash inflow/(outflow) before financing	(10.0)	(15.4)	(16.1)	(36.6)	(54.0)	(95.3)	(123.0)	(133.4)	(99.3)	(38.7)	10.3	1.7	11.0	10.4	9.6	8.8
Financing activities:																
Grants & Government contribution for investments	7.8	15.2	16.0	19.7	33.7	31.2	36.7	39.3	35.2	12.2	1.3	0.0	0.0	0.0	0.0	0.0
Customer deposits & capital contributions (connection charges)	1.8	2.0	0.8	4.3	1.1	1.3	1.6	2.1	2.7	3.5	4.4	5.3	6.3	7.3	8.4	9.6
Borrowing	0.0	0.0	0.0	8.4	19.9	61.8	85.5	92.4	62.0	30.6	5.3	0.0	0.0	0.0	0.0	0.0
Borrowing repaid	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.7)	(7.0)	(12.5)	(14.9)	(17.3)	(17.6)	(17.9)	(18.1)
Receipts/(payments) for investments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net cash inflow from financing activities	9.6	17.2	16.8	32.4	54.8	94.3	123.9	133.7	99.2	39.3	(1.4)	(9.5)	(11.0)	(10.2)	(9.4)	(8.5)
Increase/(decrease) in cash and cash equivalents	(0.3)	1.8	0.8	(4.2)	0.8	(1.0)	0.9	0.3	(0.1)	0.7	8.9	(7.9)	0.0	0.2	0.2	0.3
Cash and cash equivalents at beginning of year	4.1	3.7	5.0	5.1	0.7	1.5	0.4	1.3	1.5	1.4	2.0	10.8	2.7	2.7	2.8	3.0
Exchange difference	(0.0)	(0.4)	(0.6)	(0.2)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)
Cash and cash equivalents at end of year	3.7	5.0	5.1	0.7	1.5	0.4	1.3	1.5	1.4	2.0	10.8	2.7	2.7	2.8	3.0	3.2
Self-financing ratio (%)	9%	26%	-3%	15%	7%	4%	4%	3%	17%	23%	70%	62%	91%	96%	97%	103%
Debt service cover (times)	90.3	23.4	50.2	55.0	327.9	271.0	303.0	16.2	10.7	2.3	2.8	2.0	2.3	2.4	2.5	2.7

ANNEX 8: Schedule of REGIDESO's Electricity Tariffs

		Effective from >	June 12	March 12	Sept 2011	May 2007	June 12	March 12	Sept 2011
Basse Tension (BT) [Low Voltage]							% change	% change	% change
1.1	BT Menage (Household)								
	Fixed charges/month								
		0-50/kWh (0-100 Sept 11, 0-150 prior to Sept 11)	0	0	0	0			
		51-100/kWh (101-300 Sept 11, 151-300 prior to Sept 11)	0	0	0	0			
		> 151/kWh (> 301 Sept 11, up to 750 prior to Sept 11)	3,249	3,249	1,703	0	0.0%	90.8%	
		> 750kWh				0			
	Energy charges								
		0-50/kWh (0-100 Sept 11, 0-150 prior to Sept 11)	68	73	57	41	-6.8%	28.1%	39.0%
		51-100/kWh (101-300 Sept 11, 151-300 prior to Sept 11)	138	138	92	46	0.0%	50.0%	100.0%
		> 151/kWh (> 301 Sept 11, up to 750 prior to Sept 11)	260	260	172	85	0.0%	51.2%	102.4%
		> 750kWh				127			
1.2	BT Commerce								
	Fixed charges/month								
		0-100/kWh (0-200 Sept 11, 0-300 prior to Sept 11)	1,995	1,995	1,108	0	0.0%	80.1%	
		101-250/kWh (201-500 Sept 11, 301-1000 prior to Sept 11)	4,000	4,000	2,111	0	0.0%	89.5%	
		> 251kWh (> 500 Sept 11, > 1000 prior to Sept 11)	6,000	6,000	3,111	0	0.0%	92.9%	
	Energy charges								
		0-100/kWh (0-200 Sept 11, 0-300 prior to Sept 11)	93	93	93	116	0.0%	0.0%	-19.8%
		101-250/kWh (201-500 Sept 11, 301-1000 prior to Sept 11)	149	149	138	127	0.0%	8.0%	8.7%
		> 251kWh (> 500 Sept 11, > 1000 prior to Sept 11)	190	190	164	137	0.0%	15.9%	19.7%
1.3	Administration (Government)								
	Energy charges		149	149	138	127	0.0%	8.0%	8.7%
1.4	Eclairage Publique (Public Lighting)								
	Energy charges		151	151	139	127	0.0%	8.6%	9.4%
1.5	DGHER**								
	Energy charges		86	86	70	53	0.0%	22.9%	32.1%
1.6	Moyenne Tension (MT) (Medium Voltage)								
1.6.1	MT avec (with) Puissance Souscrite (PS) (Contracted Power) et Pointe (Peak)								
	Fixed charges/month								
	Prime de la PS (contract award power)		4,416	4,416	3,824	3,231	0.0%	15.5%	18.4%
	Surprime de la PS (premium power)		8,832	8,832	7,647	6,462	0.0%	15.5%	18.3%
	Energy charges								
	Prime de la PS (contract award power)								
		0-150 hrs	134	134	128	122	0.0%	4.7%	4.9%
		151-450 hrs	93	93	85	77	0.0%	9.4%	10.4%
		> 450 hrs				52			
1.6.2	MT sans (without) Puissance Souscrite (PS) (Contracted Power) et Pointe (Peak)								
	Fixed charges/month								
	Prime de la PS (contract award power)		7,754	7,754	5,407	3,231	0.0%	43.4%	67.3%
	Surprime de la PS (premium power)		7,754	7,754	5,407	3,231	0.0%	43.4%	67.3%
	Energy charges		104	104	113	122	0.0%	-8.0%	-7.4%
1.6.3	MT sans (without) Puissance Souscrite (PS) (Contracted Power) et sans Pointe (Peak)								
	Energy charges		152	152	145	138	0.0%	4.8%	5.1%

** DGHER (Direction Générale de l'Hydraulique et des Energies Rurales), also an autonomous entity operating under MWEM's tutelage and responsible for the provision of electricity and water in rural areas.