An Integrated Appraisal of the Péligre Electricity Transmission Line Rehabilitation Investment

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Abstract

The analytical challenges in evaluating the impacts of transmission line investments have vexed practitioners and electricity market regulators. The purpose of this study is to provide a guideline for improving the accuracy and predictability of the impacts of electricity rehabilitation projects. The subject is too broad to address completely here. The proposed guideline is suitable for evaluations of such project implemented in a broken electricity network. In such case, the demand for electricity is deterred, the supply of the electricity is unreliable, and the system is far away from its least-cost optimum production/consumption level.

The guideline does not rebut the catalog of existing evaluation models or approaches. The guideline utilizes them for a reasonable *ex-ante* assessment to identify "good" projects that satisfy the economic and public objectives of the economy. An integrated cost-benefit analysis (CBA) framework is recommended to appraise such projects along with allocating the impacts to stakeholders in a manner that is commensurate with the net benefits they receive. Such an integrated analysis is much more than a set of procedures for estimating the expected net present values or rates of return of the project.

Keywords: Electricity, Transmission Line, Rehabilitation Investment, Reliability, Cost-Benefit Analysis, Haiti

JEL Classification: D61, H43, L94

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Abbreviations and Acronyms

bbl	Barrel (of crude oil)
CaF	Capacity Factor
CBA	Cost-Benefit Analysis
CSCF/CF	The Commodity Specific Conversion Factor /Conversion Factor
ED	Economic Dispatch
EDH	Electricité d'Haïti (Haiti Electricity; Electricity Utility in Haiti)
EIRR	Internal Rate of Return (Economy)
EOCK	Economic Opportunity Cost of Capital
EOCL	Economic Opportunity Cost of Labor
GDP	Gross Domestic Product
FEP	Foreign Exchange Premium
HFO	Heavy Fuel Oil
HRF	Haiti Reconstruction Fund
HTG/gdes	Haitian Gourde / gdes
IDB	Intern-American Development Bank
IPP	Independent Power Producer
kg	Kilogram
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
MC	Marginal Cost
MTPTC	Ministry of Public Works, Transportation, and Communications
MVA	Megavolt Amp
MW	Megawatt
NPV	Net Present Value (PV = Present Value)
NTP	Non-Tradable Premium
O&M	Operation and Maintenance (Costs)
PAP	Port-au-Prince
PHP	Péligre Hydro Plant
PPA	Power Purchase Agreement
T&D	Transmission and Distribution
US$	United States Dollar
USAID	United States Agency for International Development
WB	World Bank
WTP	Willingness-to-Pay

Table of Contents

Summary

The analytical challenges in evaluating the impacts of transmission line investments have vexed practitioners and electricity market regulators. The purpose of this study is to provide a guideline for improving the accuracy and predictability of the impacts of electricity rehabilitation projects. The subject is too broad to address completely here. The proposed guideline is suitable for evaluations of such project implemented in a broken electricity network. In such case, the demand for electricity is deterred, the supply of the electricity is unreliable, and the system is far away from its least-cost optimum production/consumption level.

The guideline does not rebut the catalog of existing evaluation models or approaches. The guideline utilizes them for a reasonable *ex-ante* assessment to identify “good” projects that satisfy the economic and public objectives of the economy. An integrated cost-benefit analysis (CBA) framework is recommended to appraise such projects along with allocating the impacts to stakeholders in a manner that is commensurate with the net benefits they receive. Such an integrated analysis is much more than a set of procedures for estimating the expected net present values or rates of return of the project.

The proposed methodology is applied to the Péligre electricity transmission line rehabilitation investment project in Haiti, which is an aid-financed project by the Inter-American Development Bank through the Haiti Reconstruction Fund. The objective of the proposed rehabilitated transmission line is to provide additional energy to the electricity utility. This would be achieved through improved transmission efficiency and increased transmission capacity. Thus, saves from production costs during off-peak, earns incremental revenues from the sale energy during peak load, and saves some transmission investment costs (i.e. avoided transmission costs) for the future system expansion in genera tion.

The financial and economic analysis has confirmed that the project is a viable and sustainable investment for the electric utility in Haiti (EDH) and economy of Haiti. The expected financial NPV of the project is HTG 2,748 million (≅US$ 50 million), using a real discount rate of 8%. The expected economic NPV of the project is estimated at HTG 1,712 million (≅US$ 31.5 million), using an EOCK of 8% real. Its EIRR is 18%. Therefore, the economic analysis confirms that the project will improve the overall well-being of Haitian residents if it is implemented.

When externalities from the project are allocated to the impacted groups of people, consumers will gain by HTG 544 Million (≅US$ 9.9 million) and local labor will gain by HTG 23 Million (US$ .41 million). The potential loser is the gov’t of Haiti. The gov’t will <u>lose</u> tax revenues by HTG 427 Million (US$ 7.8 million), and the other projects will have less access to funds by an amount of

about 1,175 (US$ 21.4 million). Since operations of the electric utility, the gov't of Haiti has financed EDH, the project is also viable from the government's point of view.

The results from risk simulations also suggest that there is a very limited risk of financial and economic outcomes for the project. The Inter-American Development Bank and Haiti Reconstruction Fund are justified in providing grants for financing the implementation of the project, thus providing substantial returns with a zero risk of loss for both the electric utility and the economy in general.

1. Introduction

Haiti, officially the Republic of Haiti is a low-income Caribbean country. It occupies the western, smaller portion of the island of Hispaniola, while the Dominican Republic controls the rest of the land. Haiti remains the poorest country in the western hemisphere with a significant lack in basic services. As of 2015, nominal GDP per capita reached only US$ 818 and annual economic growth rate was always below the average of low-income countries (WB, 2016).[1] According to the latest household survey conducted in Haiti, more than 6 million people (equivalent to 60% of the total population) live below the US$ 2.42 per day national poverty line of earning and over 2.5 million (equivalent to 25 % of the total population) of people live under the US$1.23 per day national extreme poverty line of earning (ECVMAS, 2012).[2]

The educational, health and welfare benefits associated with access to affordable, reliable and sustainable energy is substantial, and the lack of these services often has adverse effects on economic growth, development and poverty reduction. The main hallmarks of poverty in relation to energy in Haiti are very low coverage of electrification, unreliable and costly supply of electricity. An insufficient and inefficient generation capacity, aging and poorly maintained transmission and distribution systems, and heavy reliance on traditional biomass use are the main characteristics of the energy sector (Ochs et al. 2015; Lucky et al. 2014). [3] Therefore, the energy sector of Haiti is currently facing two fundamental challenges: a broken power grid and a high dependency on charcoal.

The government of Haiti, with the support of donor communities (e.g. WB, IDB, USAID), has taken several initiatives to rehabilitate and modernize the power sector.[4] On December 2014, Inter-American Development Bank (IDB) and Haiti Reconstruction Fund (HRF) agreed to provide financial assistance in the form of grants for the rehabilitation the Péligre Transmission Line. [5] The general objective of the program is to improve the operational performance of the Péligre

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[1] For other growth and development indicators, visit http://data.worldbank.org/indicator/NY.GDP.PCAP.CD?locations=HT

[2] For complete survey data, see ECVMAS (2012), http://www.ihsi.ht/pdf/ecvmas/ecvmas_metadonnees/0_ECHANTILLON/0_ECVMAS_Plan%20Echantillonnage_28052013.pdf

[3] More than 90 percent of energy needs in Haiti are met through the use of firewood and charcoal. Most of the fuel-wood and charcoal are mainly used for cooking purposes and regarded as 'free' good in Haiti (i.e. lack of forestry ownership). Charcoal is made from natural trees, so they produce energy at a low conversion of energy content. Besides, the efficiency of stoves (mainly open) is very low (around 22% for traditional stoves and 30% for improved charcoal stoves). Therefore, heavy use of the fuel wood for cooking and production of charcoal, without systematic regeneration, causes further deforestation in Haiti. The increased siltation from deforestation threatens eco-system as well as hydropower production in Haiti. Therefore, as part of clean energy initiative, Haiti needs to encourage and promote the use of energy-efficient stoves.

[4] Also see post-disaster needs assessment study of Gov't, (PDNA), 2010. Action Plan for the National Recovery and Development of Haiti, Annex for the energy sector.

[5] For complete list of documents related to project, from loan approval to project feasibility study, visit http://www.iadb.org/en/projects/project-description-title,1303.html?id=HA-L1100

transmission line for more efficient and reliable electricity system. The specific objectives of the project are (i) to rehabilitate the capacity of the 115-kilovolt (kV) transmission line from Péligre to Tabarre/ Nouveau Delmas, (ii) to reduce transmission losses and power outages, and (iii) to minimize environmental and social impacts. The project will rehabilitate the power system operation's reliability and efficiency, and enhance transmission capacity. Therefore, the benefits of this project will be in the forms of (i) incremental energy saving through reduction of transmission line losses due to the higher capacity of the transmission line and (ii) incremental benefits through the additional power to be delivered by the additional transmission capacity.

The purpose of this feasibility study is first to identify the relevant costs and benefits of the proposed program (hereafter 'project') and quantify them in monetary terms. Secondly, it seeks to allocate the various impacts that accrue to the groups involved. The analysis of the program is carried out through an integrated social cost-benefit analysis, an approach that covers the evaluation of the financial, economic, stakeholder and risk aspects of the program in a single consistent model. The analysis compares the situation with the rehabilitation of the line with a "business as usual" scenario, where there is no rehabilitation (i.e. "without" project). The analysis is performed from the incremental costs and incremental benefits in <u>single</u> cash/resource flow statement, reflecting the <u>future</u> "with" the project against the future "without" the project. The sustainability of such programs is also examined to determine the risk factors that affect the performance of the Program.

This report presents the integrated analysis of the proposed transmission rehabilitation project which will help in answering the following questions:

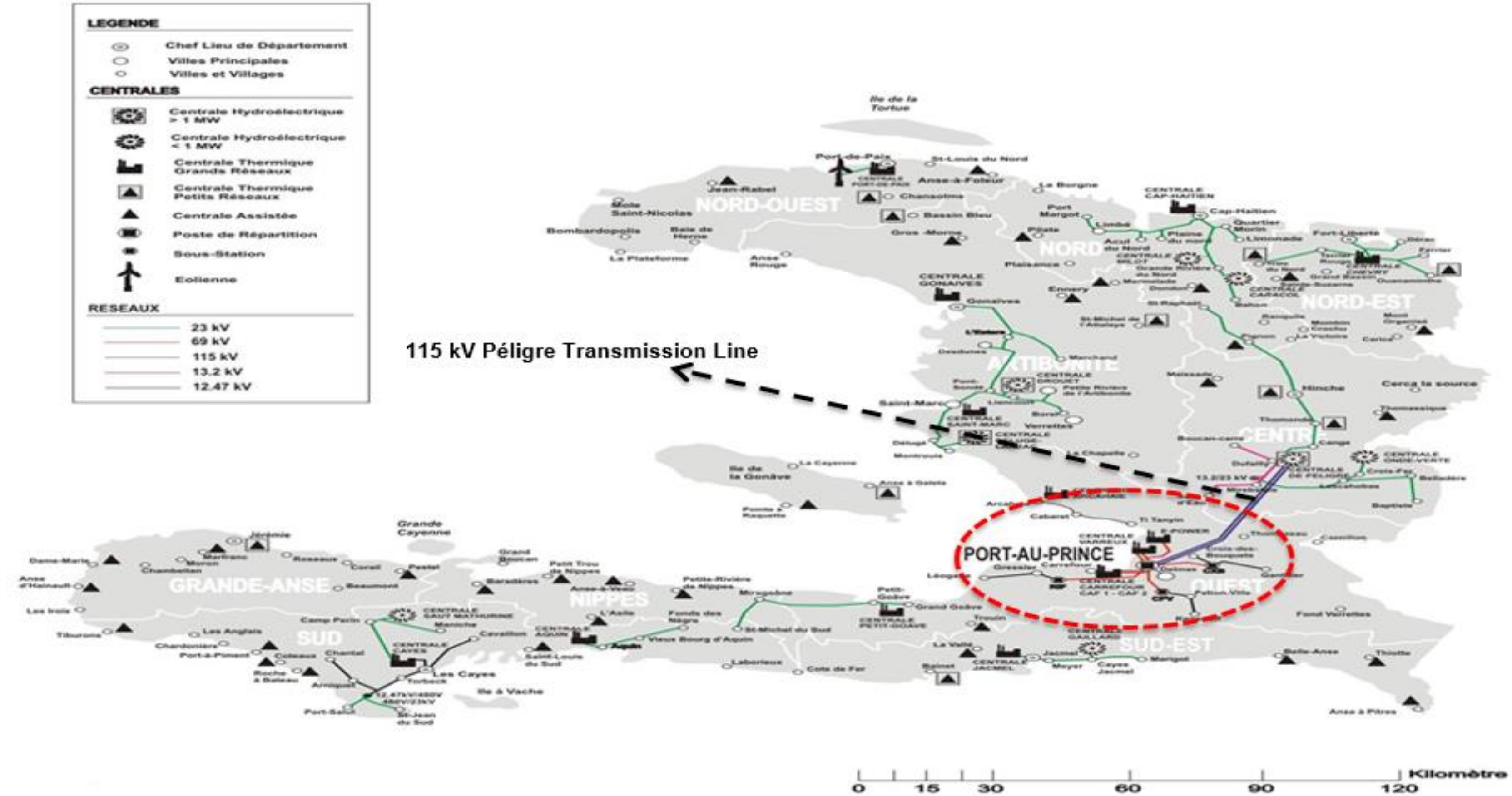
1. Is this project viable for the electric utility? What are the incremental cash flow implications for the electric utility?
2. What is the overall contribution of the project to the Haitian economy?
3. Who are the different stakeholders affected by the project and how much do they benefit or lose?

2. Electricity Sector in Haiti

2.1 Overview

The state-owned electric utility, Electricité d'Haïti (hereafter EDH), was established in 1971. It is currently in charge of transmission, distribution and commercial activities of electricity across the country. In terms of the institutional set-up, the electricity sector falls under the Ministry of Public Works, Transports, Energy and Communications (MTPTC), which has the authority to develop and implement the energy policy. It also monitors the financial side of the state-owned utility EDH, responsible for regulating and facilitating the energy infrastructure investments in Haiti.

Figure 1. Electricity Network of Haiti

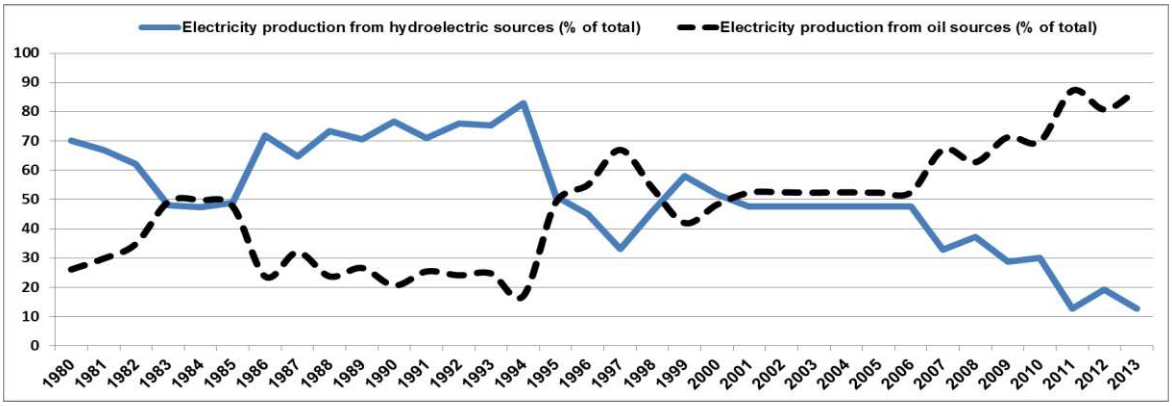


Source: EDH, 2014

The Haitian energy network does not have a single centralized transmission and distribution system but rather operates with nine isolated regional grids without any interconnection between them. The largest of the nine is Port-au-Prince (hereafter PAP). The Port-au-Prince metropolitan area includes most of the Quest province, and it is the only grid with an integrated distribution network. The 115/69 kilovolts network and substations are interconnecting the Carrefour Central, Varreux and Péligre generation stations to serve the metropolitan area. (See Figure 1).

As of December 2015, the total installed generation capacity in PAP network was around 255 MW. About 80 percent of it was based on fuel-inefficient small diesel engines burning mostly gas oil and a few burning heavy fuel oil. The diesel power plants run at a very high cost as these plants run mostly with a very low fuel efficiency coupled with the high cost of fuel imports. The heavy reliance on fossil energy in electricity generation also makes the country particularly vulnerable to rising oil prices.

Figure 2. Electricity Generation by Fuel Sources



Source: IEA Statistics 2015

Available (firm) capacity, however, is less than the installed capacity due to the aging of generation plants with a weak maintenance schedule of the plants. Out of 255 MW installed capacity, however, the total firm (available) capacity was only about 185 MW (see Table 1). This firm capacity is insufficient to meet current estimated peak load demand of more than 250 MW in the metropolitan area This results in frequent load-shedding and service interruptions.

The demand projection studies for Haiti predict that the net peak demand will grow between 5%-10% annually. Therefore, it is estimated to reach 750 MW in 2030 (Ochs et al. 2015, p.45-46), and might even reach up to 1 GW (Lucky et al. 2014, p. 24, 93). Therefore, the gap between demand-supply will narrow if generation expansion is progressive and faster than peak demand growth.

Table 1. Electricity Supply Characteristics in PAP – December 2014

Station	Plant Type	Ownership	Installed Capacity (MW)	Firm Capacity (MW)	Fuel Consumption[9] (liter/kWh)	CO2 Emission (g/kWh)
Péligre	Hydro	EDH	3 x 18 MW = 54 MW	50 MW	Water level (rainfall)	*negligible
Carrefour I	Diesel Thermal	EDH	5 x 7.9 MW = 39.5 MW	---	Gasoil; 0.310 liter/kWh	0.824
	Diesel Thermal	EDH	1 x 10.3 MW = 10.3 MW	10 MW	Gasoil; 0.310 liter/kWh	0.824
Carrefour II	Diesel Thermal	EDH	20 X 1.7 MW = 34 MW	30 MW	HFO; 0.269 liter/kWh	0.718
Varreux I[10]	Diesel Thermal	EDH & IPP	2 x 9 MW = 18 MW	15 MW	Gasoil; 0.267 liter/kWh	0.712
	Diesel Thermal	EDH & IPP	2 x 5 MW = 10 MW	8 MW	Gasoil; 0.267 liter/kWh	0.712
	Diesel Thermal	EDH & IPP	1 x 10.3 MW = 10.3 MW	8 MW	Gasoil; 0.267 liter/kWh	0.712
Varreux II	Diesel Thermal	IPP: SOGENER	4 x 3 MW = 12 MW	10 MW	Gasoil; 0.267 liter/kWh	0.712
	Diesel Thermal	IPP: SOGENER	2 x 4 MW = 8 MW	7 MW	Gasoil; 0.267 liter/kWh	0.712
	Diesel Thermal	IPP: SOGENER	3 x 1.2 MW = 3.6 MW	3 MW	Gasoil; 0.255 liter/kWh	0.681
Varreux III	Diesel Thermal	IPP: SOGENER	1 x 2 MW= 2 MW	2 MW	Gasoil; 0.255 liter/kWh	0.681
	Diesel Thermal	IPP: SOGENER	12 x 1.5 MW=18 MW	14 MW	Gasoil; 0.255 liter/kWh	0.681
E-Power	Diesel Thermal	IPP: E-POWER	8 x 4.2= 33.6 MW	30 MW	HFO; 0.229 liter/kWh	0.611
TOTAL			**253.0 MW**	**187.0 MW**	---	---

Sources: EDH, 2014; Lucky et al. 2014, p.25; IDB 2010

9 Capacities (MW), fuel consumption (liter/kWh) and emission intensity (gram/kWh) of generation units are adjusted by the author.
10 Varreux I is owned by the EDH, but rehabilitated and operated by the private IPP; SOGENER.

While the tariff is regulated by the state authority, it has not been adjusted periodically. The electricity retail tariffs have not changed since 2009.[11],[12],[13] The demand-weighted average electricity tariff is roughly 14.3 gdes per kWh (=$0.26 per kWh); where the residential electricity rate is about 11.7 gdes per kWh (=$0.21 per kWh), while commercial and industrial rates vary, but can be as high as 17.3 gdes per kWh (=$0.31 per kWh) depending on the amount of consumption. Electricity tariff in PAP is therefore not affordable for most consumers in a country with the lowest income per capita in the region. According to the World Bank, only about 50% of customers are legally connected to the power grid, and are therefore the legal customers that pay their bills. Many unconnected consumers simply either do not have the ability to pay or are not willing to pay these high electricity prices for an unreliable service. Given the availability of solar energy, various private companies supply solar systems ranging from small scale with a few watt-peak, Wp (e.g. for residential clients) to large-scale system with hundreds of kilowatt-peak, kWp (e.g. for commercial and industrial clients). Poorer households typically use kerosene or candles as their main lighting source.

The electricity charges are high and only available for an average of 16 hours per day. This crippling electricity outage has forced several businesses to rely on self-generation from inefficient and dirty diesel generating units. Although some clients use costly and inefficient self-generation as a hedge against blackouts, many (mostly large industrial customers) have decided to disconnect from the grid and independently generate their electricity at all times. It is estimated that the cumulative capacity of individual diesel generation sets is more than 200 MW – more than the total firm capacity supplied by the national grid. Hooking these households to the grid will require better reliability and regulatory reforms of electricity tariffs. The averting behavior of consumers prevents the electric utility from achieving a greater level of economies of scale in electricity generation. Therefore, it worsens the financial situation of EDH as well as perpetuates high electricity tariffs to grid-connected consumers. The high costs of electricity generation that EDH is unable to cover ends up as a heavy financial burden on the government of Haiti.

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11 See EDH, Website: http://www.edh.ht/tarif.php

12 US$ values are calculated at the average market exchange rate for 2015 at HTG/US$= 55.

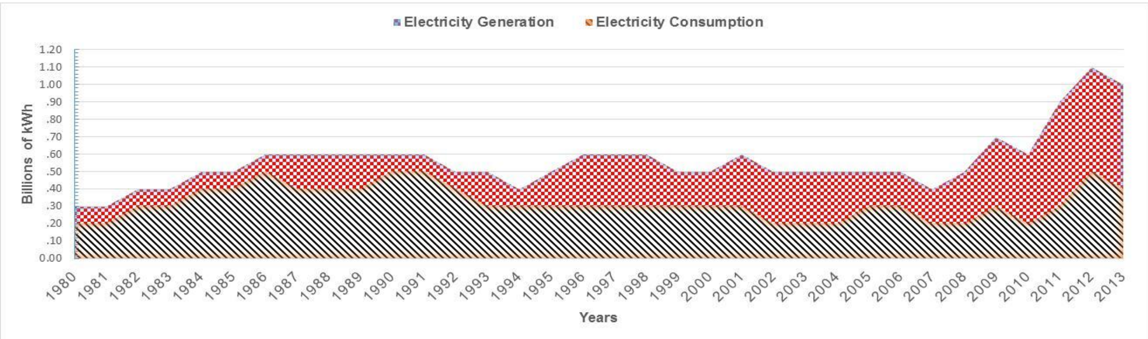
13 One of the main reason IPPs worry is that PPA will not be paid for their generation due to EDF inability to collect tariffs and high transmission and distribution losses. Therefore, periodic tariff reviews should be in place to generate reasonable energy tariff rates for utilities; that will enable EDH to cover expenses in its operations. Additionally, as part of the tariff-setting structure, there should also be regulatory targets and mechanisms for reducing technical and non-technical losses. Cash recovery for generators through reasonable electricity tariffs and fewer transmission and distribution losses can increase the quality of energy services and encourage investment in sustainable energy projects. These efforts need to be tackled at the institutional level before reaching to utility level applications.

2.2 Electricity Transmission Issues in PAP Network

The existing Péligre Transmission line constructed in the early 1970's has been run by EDH for over 40 years. It is currently connecting the Péligre Hydroelectric Plant plant to the consumers in PAP through Nouveau Delmas substation. It is an overhead 55km long 115 kV double circuit line with steel and aluminum alloy conductors, supported by 190 towers. The capacity of the existing (non-rehabilitated) transmission capacity is rated at 144-MVA. Due to deterioration of the conductors over time and inadequate maintenance, it has become obsolete and inefficient.

The Péligre Hydroelectric Plant (hereafter PHP) with a 54-megawatt (MW) nominal capacity is the most reliable source of energy supply in Haiti. Péligre transmission line currently connects the PHP to the consumers in PAP through Nouveau Delmas substation. The chronic and frequent electricity shortages in PAP is mainly caused by the low levels of available thermal generation capacity, heavy reliance on PHP and the poor reliability of the transmission and distribution lines.

Figure 3. Electricity Generation and Consumption



Source: IEA Statistics 2015

Figure 4. Electricity Transmission and Distribution Losses (% of Energy Produced, includes technical and non-technical losses)[14]

Source: IEA Statistics 2015

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[14] Electric power transmission and distribution losses include losses in transmission between sources of supply and points of distribution and in the distribution to consumers, including pilferage.

An inefficient and overburdened grid system in Haiti results in significant technical (e.g., power flow losses, line blackouts) and non-technical (e.g., theft, fraud, uncollected bills) transmission and distribution losses. To illustrate, more than half of the electricity produced is failing to reach paying customers (see Figures 3 and 4). The technical line losses are due to energy dissipated in the conductors and equipment used for transmission, transformation, sub-transmission, and distribution of power. Although reliable data on the actual technical (mechanical) losses amount is not available, these losses are reported to be about 30% of the total electricity losses.[15] The large energy losses make it difficult for EDH to recover costs, and hinder EDH's ability to invest in expanded coverage for electricity. Therefore, the transmission line requires restoration, insulation, and grounding with safe and reliable capacity for transiting electricity from Péligre to PAP metropolitan demand node.

In summary, the rehabilitation of Péligre transmission line will help the electric utility (country) to diversify its energy mix by increasing the share of the cheaper hydro source of energy in the energy mix. After the transmission lines have been fully refurbished and rehabilitated the hydro units will have enhanced grid efficiency and reliability and will be compliant with the instabilities of Haiti's electricity grid.[16] The rehabilitation of the Péligre transmission line is crucial for the operations of PHP and integral part of the plan to improve the reliability of energy service in PAP area. The completion of the rehabilitation of Péligre transmission line together with the 7 distribution circuits in PAP, and PHP will substantially improve the level of reliability. In return, these investments will allow EDH to save costs on the level of fuel importations as well as the operational and maintenance costs for thermal plants. It will be able to deliver and bill more electricity to consumers.[17]

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[15] Grid energy losses at 50% imply that consumption of 1 kWh energy will require 1 kWh of energy from off-grid distributed generation (DG) system, which is half of electricity production to be taken by a grid-connected power plant. The reason is off-grid DG systems generate electricity at the point of use without a need to pass through the grid. Therefore, high grid energy losses make distributed systems more attractive option for cost saving or an option in delivering more energy at lower economic costs. At the same time, cost savings potential through energy efficiency improvements for the same level of service is another alternative option to reduce the high economic costs from grid energy losses. The sector as a whole, however, still needs to accelerate the rehabilitation and expansion of all generation, transmission, and distribution facilities if the government's 100% electrification target is to be met in a cost-effective manner.

[16] Generation is dispatched from the lowest energy-producing generators first, then the next and so on in a merit-order of the cost of production. Therefore, the most economical generators must run the most of the time.

[17] The increase in energy transmission capacity and ambitious to increase in renewable share in electricity mix was part of Action Plan for the National Recovery and Development of Haiti of 2010. For more information, http://www.recoveryplatform.org/assets/publication/Action_Plan_12April_haiti.pdf

3. Methodology

Power system reliability considers the performance of the electricity network as a whole. It considers the integral coordination between generation facilities, transmission network and the distribution grid. The primary drivers for electricity transmission investments (e.g. upgrades or rehabilitation of existing facilities, and new expansions) are either reliability considerations or interconnection of new generation facilities into the grid, or both. A new transmission project can provide a broad range of benefits. The measurement of all the widespread and diverse impacts of transmission capacity investment on an integrated network presents analytical challenges.

Ideally, electricity retail rates (market prices) would reflect the monetary value of the net benefits from a typical transmission investment. However, the economy-wide benefits of new transmission investments might not be only in the form of production cost savings that are reflected in electricity rates. The load-differentiated impacts due to the changes in the transmission losses and the changes in the transmission line availability from a rehabilitated transmission line project also provide economic benefits.

The standard criteria for transmission investments is focused on minimizing the social cost of transmission investments and losses in the network – subject to the system constraints of present and planned demand and generation capacity, and the regulatory reliability standards[18]. The standard of positive net present value (i.e. Accept) or negative net present value (i.e. Reject) can be used as an indication in the planning process[19]. The situation in Haiti requires a more advanced appraisal because of the presence of shortages, unplanned outages, high transmission losses, and even suppressed demand for new connections.

To avoid such pitfalls, this study evaluates the benefits from the rehabilitation of this transmission line with a focus on the current situation in Haiti. The costs and benefits are first identified and valued from different perspectives, then compared to determine the project's overall net benefits. Estimation of the project benefits and costs are based on well-established principles of welfare economics.[20] The proposed electricity transmission rehabilitation project is evaluated based on the CBA guideline prepared by Jenkins, Kuo and Harberger (2011).[21,22]

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18 See Kirby and Hirst (1999), Stoft (2002) and Wu et al. (2006).

19 See Hunt (2002).

20 See Harberger, A.C. (1971), "Three Basic Postulates for Applied Welfare Economics", Journal of Economic Literature, 9(3): 785-797.

21 For the complete chapters of the manual and its applications on various projects, visit https://ideas.repec.org/s/qed/dpaper.html, Jenkins, G.P Publications in 2011.

22 For example, see Jenkins et al. (1999) for an application of CBA in evaluating the expansion of electricity transmission system in Mexico.

4. Project Summary

4.1 Project Description[23]

The proposed transmission rehabilitation project (hereafter project) consists of the rehabilitation of two circuits: (1) the above-ground rehabilitation of the capacity of transmission from PHP to the area of Tower 152 east of Grise River and (2) construction of an underground transmission line covering a distance from tower 152 to Nouveau Delmas substation in PAP[24] (See Figure 5).[25]

The above ground rehabilitation of the capacity of transmission line consists of:

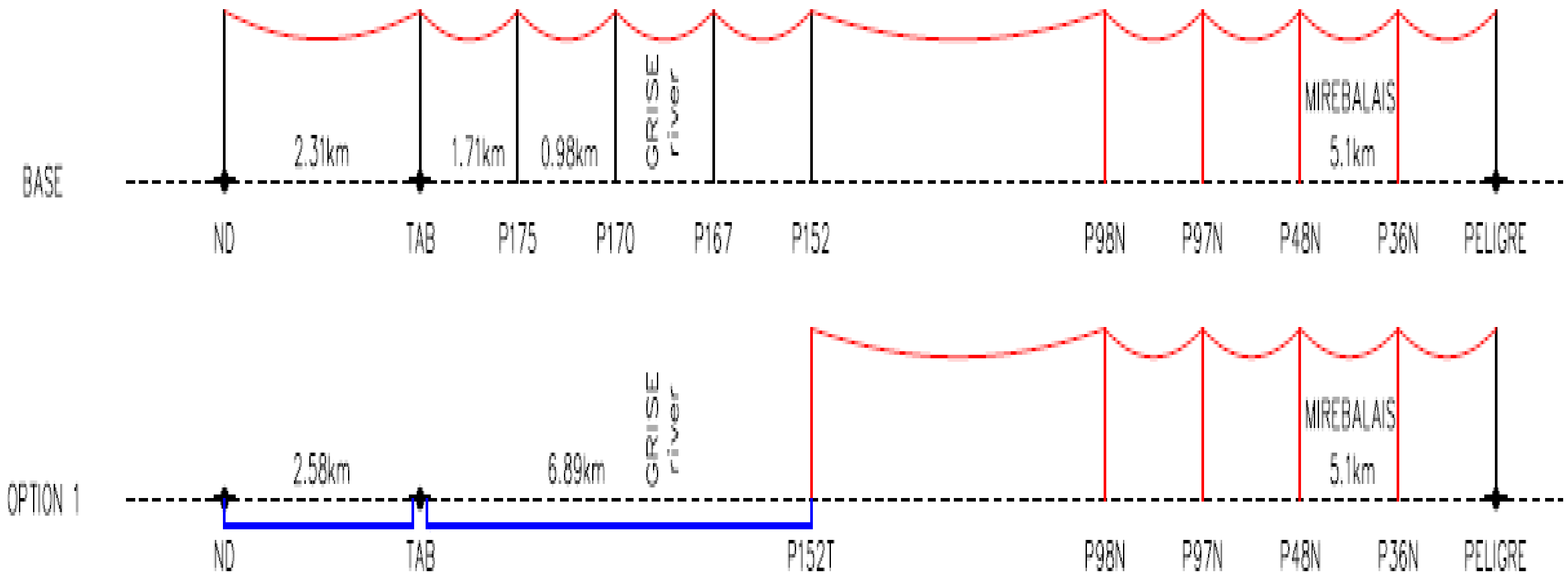
- The replacement of conductors by new conductors with higher capacity and lower losses.
- The replacement of the earth wire by an Optical Ground Wire.
- The replacement of the overhead line equipment (insulator chains).
- Elimination of the instability risk of the towers affected by illegal mining.
- Bypass in [the] overhead line of town Mirebalais.
- The length of the rehabilitated overhead line (including bypass) is 42.7 km.

The construction of an underground transmission line consists of:

- Installation of the Péligre transmission line in the underground at Port-au-Prince:
    - 2 circuits 80 MVA underground between substation Nouveau Delmas and Tabarre (2.6 km) and 2 circuits 80 MVA underground between substation ND and Tabarre (6.9 km).

[23] http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=37718165
[24] Among other five options (available at http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=39165061), option 1 is selected because the social and environmental impacts are minimized from selection option 1.
[25]For the technical characteristics of the transmission line project and map of the project, see Annex A .

Figure 5. Péligre Transmission Line Current Design (Base) and Project Design (Option)



Source: AECOM / IDB, 2014, p.29[26]

[26] See full report available at: http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=39242382

4.2 Project Costs and Project Financing Instruments

The following incremental costs from project construction and operations are estimated for the rehabilitation facility. All the costs are stated in real 2015 prices.

All the investment equipment items are expected to have an economic life of 55 years (Bonneville Power Administration, BPA, 2013, p.41). Since the economic life of assets is longer than the period of the project analysis, there will not be any replacement of the assets during the line operations. Residual values are estimated and reported for the last period of the appraisal.

Investment Costs

The total investment cost is estimated to be US$ 23.8 million. The project costs are segregated into three categories: (i) technical costs, ii) resettlement, implementation, and supervision costs, and (iii) labor costs. Technical costs amount to US$ 18.74 million. The resettlement, implementation, and supervision costs are estimated at US$ 1.2 million. While the labor costs amount to US$ 3.86 million (see Table 2). It is initially assumed that there is a zero risk of cost overrun.

The sub-component (A) investment costs includes the financing of the investment to rehabilitate and improve the capacity of the transmission line, is as follows: (i) rehabilitation of the capacity of the overhead transmission line (115- kilovolt (kV) from the PHP to Tower 152 (east of Rivière Grise), with the replacement of overhead conductors, insulators and hardware and replacement of guard cable in order to improve communication capacity; and (ii) the construction of an underground transmission line covering a distance of about 10 kilometers (km) from around tower 152 to New Delmas, through to the new substation of Tabarre. The foreign suppliers quote CIF prices for imported equipment and materials, not including transportation, insurance and port handling to the project site. These costs are to be covered by the project. All imported capital items are exempt from any import duty or VAT.

The sub-component B will fund all costs associated with compensation and acquisition of housing for people affected by the rehabilitation of the line. This includes the compensation of farmers and businesses for profit and income losses, as well as management and communication expenses of resettlement activities. The Project has selected a technical design for the transmission line that minimizes the number of persons to be resettled. Some families will be uprooted and resettled on another piece of land, but there will be no involuntary resettlement.

Table 2. Costs of the Program (Real, US$)*[27]

COMPONENTS	FINANCING		TOTAL (US$)	SHARE (%)
	HRF	IDB		
Sub-Component A – Transmission Line Investment Costs				
Supplies of Conductors & Equipment, underground links	6,578,000	3,542,000	10,120,000	43%
Supplies of Conductors & Equipment, over-ground links	3,997,500	2,152,500	6,150,000	26%
Equipment and Supplies for Repairs, Substation & Civil Works	1,254,00	675,500	1,930,000	8%
Insurance, and Handling and Transportation Services	351,000	189,000	540,000	2%
Subtotal	**12,181,000**	**6,559,00**	**18,740,000**	**79%**
Sub-Component B – Resettlement Costs and Compensations				
Land acquisition and Housing Construction Costs[28]		430,000		
Compensation of Farmers and Farming Land Owners[29]		210,000		
Compensation of Businesses[30]		220,150		
Administrative and Management Costs for Resettlement Work		340,000		
Subtotal		**1,200,150**		**5%**
Sub-Component C –Direct Labor Costs[31]				
Skilled	1,644,040			
Semi-Skilled	1,010,400			
Unskilled	1,208,853			
Subtotal	**3,863,293**			**16%**
GRAND TOTAL	**16,044,293**	**7,759,150**	**23,803,443**	**100%**

Sources: IDB (2014, 2016), MTPTC & EDH (2014).

(*) Values are disaggregated and adjusted by the author. All investments costs are equally distributed over 4 years, and are estimated at the zero escalation of investment costs (cost-overrun factor=0%).

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27 Program costs presented in reference documents include investment and construction costs, but do not separate labor costs both material and construction costs

28 See Annex B.

29 See Annex B.

30 See Annex B.

31 See Annex B.

In addition, the compensation of the affected groups of people/businesses is equal to their income/property losses due to the project. Hence, there are no other negative externalities associated with the project. Other potential environmental impacts during construction of transmission line, such as vibration, noise, impacts on traffic, are short-term and negligible.

The sub-component (C) will fund all labor costs associated with construction of the line. The project will employ 167 workers for the construction of the transmission line. The project will employ three types of labor during the construction of the line: skilled (engineers and managers), semi-skilled (administrators and technicians) and unskilled labor. Of the 167 workers, the project will employ a total of 24 skilled labor (20 engineers and 4 managers), 23 semi-skilled (6 administrators and 17 technicians), and the rest will be unskilled workers.

The project will hire all labor from the local labor market. Unskilled workers will be hired from the relocated families in each section of construction. The project wage rates (real) 68,000 HTG/month (1,236 US$/month) for skilled, 35,000 HTG/month (630 US$/month) for semi-skilled and 10,000 HTG/month (182 US$/month) for unskilled labor. All wages are given as gross of personal income taxes. Real wages are expected to rise at 2% per annum.

The first source of investment financing will come from foreign grants, managed by Haiti Reconstruction Fund (HRF). The HRF grant covers about 65% of the total technical costs, or US$ 12.2 million. The HRF funds will also cover all labor costs associated with construction of the line, which amount to US$ 3.9 million.

The second source of the project financing will come from a foreign grant (aid), through the Inter-American Development Bank. The IDB will cover approximately 35% of the total technical costs (CIF price) that is equal to US$ 6.6 million. IDB funds will also cover all costs associated with the resettlement and compensation, which amount to US$ 1.2 million. The grant disbursement schedule over the years before the commissioning of the project is presented below.

Table 3. Tentative Disbursement Schedule by Funding Institutions

Source / Year	Year 1	Year 2	Year 3	Year 4	Total
HRF	2,663,887	3,353,671	4,051,257	5,975,487	16,044,293
IDB	1,163,873	1,551,830	1,939,788	3,103,660	7,759,150
Total (US$)	3,827,750	4,905,501	5,991,045	9,070,147	23,803,443
Shares (%)	**15%**	**20%**	**25%**	**40%**	**100%**

Source: IDB (2014)

Table 4. Incremental Periodic O&M Expenses (Real, US$)[32]

Overhead Transmission Line O&M expenses/ km	2,000 US$	km/year
Distance of Existing Line (without project) (km)	50.7	km
Total O& M Costs (A)	101,400	US$/year
Distance of New Overhead Line (with project)(km)	42.7	km
Total O& M Costs (B)	85,400	US$/year
Difference C= (B-A)	-16,000	US$/year
Underground Transmission Line		
Annual O& M Costs (D)	20,000	per year
Periodic, Every 10 Years (E)	60,000	per 10 year
Annual Incremental O&M Costs F=C+D	4,000	US$/year
Incremental periodic (every 10 years) O&M Costs = E+ F	64,000	US$ /every 10 year

Source: IDB, 2014b, np.

[32] Data is available at http://www.iadb.org/en/projects/project-description-title,1303.html?id=HA-G1030.

Operating and Maintenance Costs

The annual regular operation and maintenance (O&M) facilities include all necessary activities to keep the underground and overground lines in proper operating condition. These charges mostly include personnel for operating and controlling the line, inspection of the line as part of routine maintenance activity, etc.[33] The incremental annual O&M costs are calculated at 4,000 US$/year (see Table 4).

In addition to annual operation and maintenance, electric utility will have to inspect the underground line as part of routine maintenance activity and replace the damaged items if any, and other necessary activities to keep the line in proper operating condition. The incremental periodic O&M activities are scheduled for every 10 years for the underground line.

The periodic O&M costs are estimated at 60,000 US$ for every 10 years starting from the first year of operation. Therefore, the total incremental annual O&M costs are calculated at 4,000 US$/ year. This figure becomes 64,000 US$ every 10 years. The electric utility revenues will cover these costs.

4.3 Identification and Valuation of Incremental Project Benefits

The focus on benefits will be on the identification and valuation of such benefits while avoiding technical and engineering details that are unnecessary for the analysis. The project will improve the reliability and quality of network operations and expand the current capacity from 144 MVA to a rated transmission capacity of 160 MVA. Therefore, the project will increase the load serving capability and produce benefits in the forms of (1) incremental transmission through a reduction of transmission line losses and at a higher transmission line availability and (2) incremental transmission benefits through the additional power delivered by the additional transmission capacity it will provide.

4.3.1 Assumptions and Facts Underlying the Project Benefits

The electric utility, EDH, will not abandon existing transmission line until the completion of rehabilitation. This is because operations of the existing transmission line will not interference with the construction works of new transmission infrastructures. Therefore, the electric utility will keep continuing to deliver energy from existing transmission line during the construction of the rehabilitated line.

Based on electricity network of PAP region presented in Figure 1, the energy production technology connected to the (unimproved) transmission line is the existing hydro plant with 50 MW firm capacity. Available spare capacity on the

[33] Although these costs are subtle in proportion to the upfront investments costs, the future benefits of the project strictly depend on monthly O&M activities of the line, as they are preventive measures to supply power to the consumers reliably and economically during the operations of the transmission line.

existing (unimproved) transmission line would allow the electric utility to expand generation capacity by the amount of 20 MW.[34] Due to the expansion of transmission line capacity "with" the project, EDH will be able to connect an additional 10 MW generation capacity into the PAP grid. In this study, the planned generation investment is assumed to be a hydro plant.

4.3.2 Identified Project Benefits and Valuation Technique

Based on supply assumptions described in the earlier section, the three main identified benefits of the rehabilitation of the line consist of:

1. ***Incremental Transmission Benefits from Existing 50 MW Hydro Plant plus 20 MW Planned Hydro Plant***[35]

    - The incremental off-peak load energy transmitted due to improved transmission line efficiency (i.e. the reduction in transmission losses at a higher level of transmission line availability during off-peak load hours).[36]
    - The incremental peak energy transmitted due to improved transmission line efficiency (i.e. the reduction in transmission losses at a higher level of transmission line availability during peak load hours.[37]

2. ***Incremental Transmission Benefits from Additional 10 MW Planned Hydro Plant***[38]

    - The incremental peak and off-peak energy transmitted from additional generation capacity due to enhanced transmission capacity (i.e. expansion of capacity from 144 MVA to 160 MVA)[39]

3. ***Benefits from Residual Values of New Transmission Line Assets***

    - The benefits of transmission line assets at the end of the project operations (i.e. residual value of assets)

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[34] Wind, Solar and Hydro are the three alternatives for the planned generation investment. Both wind and solar sources of energy supply present grid-reliability problems as they are intermittent and non-dispatchable (i.e. supply of energy cannot be turned on and off with a changing demand for electricity over time). Therefore, planned generation is assumed to be hydro as the seasonal and diurnal variability is less intermittent than the wind and solar (Lucky et al., 2014). What is more, the cost of electricity generation from hydro is the cheapest among all other forms of supply of electricity in Haiti (Lucky et al., 2014).

[35] See Annex D, equation 7.

[36] See Annex D.

[37] See Annex D.

[38] See Annex D, equation 8.

[39] See Annex D.

Table 5. Benefit Categorization and Proposed Evaluation Method

Benefit Category	Load	Approach	Evaluation
Production Cost Savings	Off-Peak	The additional off-peak energy will displace (energy clipping) an equivalent amount of total MWh energy previously supplied by the highest MC plant that serves PAP consumers. Such benefits come from the 70 MW Hydro plant capacity, and will displace energy from the least-efficient plant running during off-peak load hours of utility operations.	Avoided (reduced) thermal generation costs, valued @ economic dispatching.
Incremental Energy Sales	Peak	The additional peak energy available will be delivered to existing connected customers. Consumers will purchase additional energy at the utility rate of energy tariff. These benefits come from 50 MW existing peaking hydro and 20 MW planned baseload hydro capacity. The additional peak energy will displace an equivalent amount of total MWh energy previously produced through self-generation sources. The consumption of additional peak energy is assumed to be distributed evenly across consumers. Savings is measured by change in variable costs. No capital costs are included.	Grid substituted energies valued @ electricity tariff per kWh for financial analysis. (Electric Utility, EDH) Avoided cost of self-generation of electricity valued @ marginal coping costs per kWh, for economic analysis. The difference will be consumers' surplus.

Transmission Line Costs Avoided for Generation Expansion	Off-Peak & Peak	Avoided transmission capacity costs from an additional planned 10 MW generation capacity, connected to rehabilitated transmission line. The benefits are due to enhanced transmission capacity.	Additional power (net of all losses) transmitted from 10 MW generation capacity, valued at fixed transmission charge per kWh.
Residual Values of Transmission Assets	---	Residual values for all equipment are added as part of benefits at the end of the project operational life. Assets will be liquidated at their book value in year 44.	Valued using the straight-line economic depreciation method applied to the initial values – but with an adjustment for inflation.
Grants	---	Investment costs are financed through grants by HRF and the IDB. The transfers are part of utility benefits, but are not economic benefits.	Attached to investments costs, so grant amounts are subject to increase in investment costs and deducted from the utility's cash flow statement.
Environmental Impacts	Off-Peak & Peak	The social cost of carbon (US$/ton) is used to monetize emission benefits. In order to capture net impacts on locals in Haiti, such benefits are computed at 0.1% of the global impact.	The additional off-peak energy will displace heavy fuel (in liters), and peak load energy will displace diesel oil (in liters). Emission savings are calculated at the average carbon content of fuels displaced (kg/liter), converted to the metric ton of CO2 equivalent.

The value (utilization) of additional electricity transmitted during the peak-load is different from the benefit of additional electricity available during off-peak load hours. The evaluation of project benefits accrued at these different load hours must depict the situation in Haiti. The impacts from the existing hydro generation and planned hydro generation units must also capture the true benefits of the proposed project.

Monetizing the Transmission Benefits from 70 MW Hydro Capacity

The total firm generation capacity in PAP network is sufficient to meet current off-peak energy demand, and future investments in the generation will be covering the need for off-peak energy demand over time. Therefore, the transmission project, strictly speaking, will not result in any additional electricity consumption during off-peak load hours. The electricity generation from either the 50 MW existing hydro plant or the 20 MW planned hydro capacity will not change "with" the project. However, the amount of electricity transmitted from the same levels of electricity generation will increase in both load periods. The incremental off-peak energy transmitted will displace energy generation elsewhere to meet the off-peak demand. Therefore, the incremental energy delivered is valued at the supply (generation) level in the form of production cost savings.

On the other hand, the total firm generation capacity is in a deficient position in Haiti to meet current peak demand. Therefore, the project will contribute to meet the energy demanded during peak load hours. It is assumed that the electricity consumers will purchase all incremental peak-load energy delivered by the electric utility. Note that the project will not eliminate the reliability problem associated with the generation capacity deficit. The incremental peak-load energy due to an improved transmission line is valued at the demand (consumption) level. The calculations of incremental peak and off-peak energy delivered from these hydrogeneration capacities are based on reliability parameters used for the "with" and "without" project situation.

Monetizing the Transmission Benefits from Additional 10 MW Hydro Capacity

The incremental energy benefits from the additional 10 MW generation capacity are directly attributable to the generation project. Therefore, the energy transmission benefits due to enhanced transmission capacity are valued at the long-run fixed transmission charge per kWh as part of network charges – not at the energy charge per kWh.[40],[41]. The incremental benefit

[40] The capital cost dominates the costs of the transmission line investments. There is no fuel cost involved with operating transmission and distribution wires. This implies zero marginal cost of loading for a given transmission line with additional electricity unless the transmission line is operating at its rated capacity limit and constrained off. For details of load differentiated transmission pricing under the line congestions, see Hogan (2011), Hunt (2002, p.196-201), Perez- Arriaga et al. (1995).

[41] If these benefits are valued at the energy charge per kWh, then all costs related to the additional 10 MW hydro capacity investment must be deducted from cash/resource flow statement.

from an additional 10 MW generation capacity, in the form of net additional energy flow on the transmission line, is subject to line losses and line outages of the improved transmission system.

4.4 Project Variables and Assumptions[42]

The assumptions used in the estimations of costs and benefits are the following.

4.4.1 Timing

Construction of the line will start in year 0 (base year; 2015), and it will take 4 years to complete before it gets online. The operational lifetime considered for the project is 40 years, which is a standard value for the operational lifetime of a power transmission line.The appraisal is conducted using the domestic price level of year 0 as the numeraire.

4.4.2 Load Hours

Total load hours in a year are 8,760 hours (= 365 days/year * 24 hours/day). The assumption used in this feasibility study is that peak load demand block represents 25% of the total load hours (8,760 * 25% = 2,190 hours) while off-peak hours demand block represents 75% of the total load hours (8,760 * 75% = 6,570 hours).

4.4.3 Supply of Electricity and Capacity Expansion on Transmission Line

a. Existing Peaking Hydro Generation Capacity

Without Transmission Rehabilitation: The existing Péligre hydropower plant operates at a firm (available) capacity of 50 MW, and is already connected to PAP via the current transmission line. The existing PHP mostly runs in a peaking mode. The capacity factor of the existing hydro plant is 100% during peak hours and 30% during off-peak hours.

With Transmission Rehabilitation: The available hydro capacity and capacity factors of the existing hydro dam are assumed to remain the same during the operational lifetime of the proposed transmission project.

b. Planned Baseload Hydro Generation Capacity

Without Transmission Rehabilitation: The construction of the planned hydro plant will start in year 2 (2017) and will take a total of 2 years before it gets online. Therefore, it will be commissioned in year 4 (i.e. 2019). The planned hydro plant with a capacity of 20 MW will supply power during baseload hours (i.e. a total of 8,760 hours of which 2,190 peak hours and 6,570 off-peak

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[42] Annex C, summarizes the list of all inputs parameters and assumptions used in the appraisal.

Table 6. Existing (already connected) and Planned (to be connected) Hydro Capacities on Péligre Line

	Without Project		***With Project***		***Incremental Change***[43]	
Firm Capacity/ Capacity Factors	**Off-Peak Hours** A	**Peak Hours** B	**Off-Peak Hours** A'	**Peak Hours** B'	**Off-Peak Hours** A'-A	**Peak Hours** B'-B
Existing Péligre Hydro (Peaking)	50 MW @ 30% Capacity Factor	50 MW @ 100% Capacity Factor	50 MW @ 30% Capacity Factor	50 MW @ 100% Capacity Factor	--	--
Planned Hydro Plant (Baseload)	20 MW @ 80% Capacity Factor	20 MW @ 80% Capacity Factor	30 MW @ 80% Capacity Factor	30 MW @ 80% Capacity Factor	10 MW @ the same Capacity Factor	10 MW @ the same Capacity Factor

Source: EDH (2014) & WB (1976)
(*) values for existing hydro are re-adjusted by the author to represent situation after the rehabilitation of Peligre Hydro dam.

43 Abstracting from auxiliary consumption, net energy generation is the amount of electricity a generator produces over a specific period (e.g. available capacity * capacity factor * hours of load). As stated, the NET incremental energy delivered from the generation capacities, however, are subject to the changes in the transmission reliability (e.g. net generation = gross generation net of transmission and distribution losses).

hours). The capacity factor for planned hydro plant is assumed to be 80% during peak-load hours and off-peak load hours.

With Transmission Rehabilitation: The total maximum planned hydro generation capacity "with" the project is 30 MW. [44] The extra 10 MW planned hydro plant capacity is also assumed to supply baseload energy demand at the same capacity factors during peak and off-peak load hours. The construction year and the period year to the start of operations of the additional 10 MW hydro plant is assumed to be the same.

4.4.4 Transmission System Efficiency

Transmission system reliability is measured in terms of the transmission system availability (net of a number of planned line outages and unplanned line outages) and the transmission line losses when it is available for operation (Mazer, 2007; Harris 2006). The improvements in the transmission system efficiency will increase the load serving capability from generation to delivery. The annual incremental energy transmissions are calculated from the reductions in technical transmission line losses and the increase in transmission line availability.

Transmission Line Availability (%)

It is essential for transmission lines to undergo (planned or scheduled) regular outages for maintenance, which can extend their useful life by 30 to 50 years. This is a regular recurrent process and imposes fixed non-available hours required for planned maintenance. The regular maintenance of the line is mostly scheduled during off-peak load hours. For the existing transmission line, the total average days spent for (planned) regular maintenance is assumed to be 15 days per year. Therefore, a total of 360 hours is not served during off-peak times of the year. The improved transmission line, however, will require less time and effort for regular maintenance. The average number of days spent for (planned) regular maintenance is assumed to be approximately 7 days per year. Therefore, a total of 168 hours will not be served during off-peak times of the year.

The unplanned line outages are assumed to coincide with peak load hours only. The number of unplanned line outages without the project is 12 outages per year, of an average duration of 4 hours (IDB, 2016).[45] With the project, the rehabilitation of the line would increase reliability by lowering the number of unplanned line outages to 6 outages per year, of an average duration of 4 hours. Therefore, the annual availability of the transmission line will be further increased by a total of 24 hours during peak hours.

[44] http://www.bme.gouv.ht/energie/National_Energy_Plan_Haiti_Revised20_12_2006VM.pdf
[45] See http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=40195164

Table 7. Transmission Line Reliability Indicators for Benefit Calculations[46]*

Reliability Index	***Without Project***		***With Project***		***Incremental Change***	
	Off-Peak A	Peak B	Off-Peak A'	Peak B'	Off-Peak A'-A	Peak B'-B
Transmission Line Operational Availability (a_{lt})	94.5%	97.8%	97.4%	98.9%	**+2.9%**	**+1.1%**
(Technical) Transmission Line Losses (ρ_{lt})	4% (+0.1/year)	8% (+0.2/year)	1% (+0.02/year)	2% (+0.04/year)	**-3% (-0.08/year)**	**-6% (-0.16/year)**

Source: IDB (2014).
(*) values are re-adjusted by the author to calculate each transmission reliability indicator.

[46] See Annex D.

Taking both planned and unplanned transmission line outages into account, the availability of transmission line will increase from 94.5% to 97.4% during off-peak load hour, and from 97.8% to 98.9% during peak hours of system operation.[47]

(Technical) Transmission Line Losses (%)

Due to the lower electrical resistance of the new conductor, the line losses with the project are much lower than the losses occurring with the existing line. The transmission line is usually congested and mostly constrained in peak hours. This might result in higher frequency of line losses and blackouts during peak load hours, for example. Therefore, time-differentiated reliability analysis is required when assessing the impacts of any electricity project including transmission projects.

With the project, the technical transmission line losses will decrease from 8% to 2% during peak hours of operation, and from 4% to 1% during off-peak load hours. However, the technical line losses are not static. Due to the depreciation of the lines, there will be an increase in line losses. For example, the technical transmission line losses on the existing transmission line will increase by 0.2% and 0.1% every year during peak and off-peak load hours, respectively. Similarly, the technical transmission line losses on the improved transmission line will increase by 0.04% and 0.02% every year during peak and off-peak load hours, respectively. As expected, the unimproved transmission line will depreciate at a faster rate than that of the improved line.

Therefore, at the same quantities of energy generated "with" and "without" the project, the quantities of both off-peak load energy and peak-load energy delivered will change-over-time, subject to changes in transmission line reliability indicators.[48]

4.4.5 Electricity Generation Costs and Prices

i) Electricity Generation Cost from the Least-Efficient Off-Peak Plant

The incremental off-peak energy transmitted will displace the same amount of energy produced by the least-efficient generator running during off-peak load hours. The reduced load factor of the least-efficient plant will reduce the production cost of the electric utility. The kWh of displaced thermal energy is converted into fuel savings by multiplying them by its fuel consumption per kWh (liter/kWh). The fuel consumption of the least-efficient plant running during off-peak load hours is a HFO diesel plant that is currently consuming 0.26 liter of fuel for per kWh generated. The average fuel efficiency of the least-efficient plant is assumed to be improving at a rate of 0.75% per year[49].

[47] See Annex D.
[48] See Table 6, and Table 7, alongside with Annex D.
[49] Table 1 on page 5 summarizes the current fuel and plant mix for electricity generation in PAP metropolitan demand node. Haiti will experience ongoing grid rehabilitation in its electricity sector.

The electric utility also will be able to save some operation and maintenance costs from reduced the load factor of the least-efficient plant. The average operation and maintenance (O&M) cost of the least-efficient off-peak plant are assumed to be fixed at US $ 15 per kW, or approximated at US$ 0.094 per kWh (= 15 US$/ 8,760). The average O&M cost of this plant is assumed to remain constant throughout the lifetime of the project.

ii) System Electricity Generation Costs and Retail Electricity Tariff

The sales of incremental peak-load energy are valued at the retail electricity tariff. The future prices of electricity generation (HTG/kWh), reflected by the retail prices, among many other factors, are also subject to fluctuations in oil prices (HTG/liter), future installation of new and possibly more efficient generation plants and the future changes in the fuel mix of power plants to generate electricity (liter/kWh) etc.[50]

For the sake of simplicity, the energy charge of the electricity tariff is assumed to be set at 70% by heavy fuel oil (HFO) diesel plants and 30% by diesel oil diesel plants. The average marginal fuel consumption of HFO and diesel oil plants are 0.24 liter/kWh and 0.32 liter/kWh, respectively. The average fuel efficiency of system power plants is assumed to be improving at a rate of 0.75% per year. Fuel efficiency gains are reflected by the overall system marginal cost of electricity generation, and in the retail electricity charges. This rate is applied on an annual basis, and essentially captures the changes in the fuel cost of electricity generation from the "improved" system efficiency. This is independent of the proposed transmission line project.

In addition to the improved network efficiency, electricity generation cost also reflects the volatility in oil prices. In the analysis, the future retail electricity tariff is assumed to follow the changes in variable electricity generation costs and a rate of inflation.[51] The retail price of electricity is subject to 5% tax for consumption and charged only on the variable energy cost component of the market price. In addition to variable fuel cost for electricity generation, the average variable operating and maintenance costs of the system is estimated at 0.003 US$/kWh, and it is assumed to remain constant. In Haiti, the retail electricity pricing is not different between load hours.

To arrive at the average fixed retail price of electricity, fixed additives in the form of long-run electricity transmission charge at 0.02 US$/kWh, long-run distribution charge at 0.01 US$/kWh, and capacity charges at 0.03 US$/kWh are included in the final retail price.

The rehabilitations will be in the form of higher penetration of more efficient generation technologies and improved transmission/distribution system. These investments will allow the electric utility to produce electricity at lower production costs per kWh from improved overall grid operations (e.g. reduction in transmission and distribution losses).

[50] See Annex E, equation 9 and 10.

[51] See Annex E.

iii) Domestic Fuel Cost for Electricity Generation

For the calculation of the fuel cost for electricity generation, the long-run average crude oil price is projected to be on approximate average 50.00 US$ per barrel; the average annual historical prices from the year 1974 to 2015.[52] To arrive at the domestic cost of fuel for electricity generation, other charges are included. These charges are the refinery charges (20% of crude oil price for heavy fuel and, 10% of the crude oil price for diesel oil) and international transport charges (20% of crude oil price). After calculating its domestic price at the port, the domestic transport charges (10% of the port price) are also included in the wholesale price of fuel. In Haiti, there is no import duty or other forms of turnover tax on petroleum products, but the excise duty is levied on the border price, and it is currently at about 6%. Although the government of Haiti imposes an extra charge on the petroleum products, the electric utility is exempted from such additional charges on fuel imports.

4.4.6 Transmission Line Assets Life

The economic (useful) life of new transmission assets from rehabilitation is 55 years. The residual values of the assets will be estimated for supplies of conductors, equipment, and materials of both overground and the underground line. The residual values of assets are calculated using straight-line depreciation method and liquidated at their book value in year 2059.

4.4.7 National Macroeconomic Parameters

The financial analysis of the project is discounted at 8% (real).[53] The inflation rate in Haiti (domestic inflation rate) is assumed to be 10% and 3% in the USA. Both inflation rates are assumed to remain constant during the life of the project. The real market exchange rate of 55 HTG per US$ is assumed to remain constant during the life of the project (i.e. 0% real appreciation/depreciation factor).[54] The projected nominal market exchange rates in the following years will depend on the relative inflation experienced over time between US$ and HTG.

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[52] See Annex E.

[53] The required rate of return for a state-owned electric utility is regarded as a positive rate allowing "public" utility to cover its costs from operations and earn "fair" return to finance expenses for future system expansion. It is, however, very difficult to know about the opportunity cost of funds because aid flows are huge and uncertain.

[54] The real exchange rate appreciation in Haiti is not the outcome of an increase in productivity growth. The amount of transfers (e.g. foreign aid flows and remittances) and political risk explain the fluctuations in real exchange rate.

5.Integrated Feasibility Analysis

Traditional approaches to investment appraisal have tended to carry out a financial analysis of a program that is separate from its economic evaluation. The integrated appraisal combines the financial, economic, stakeholder and risk analysis into a single model (Jenkins et al., 2011). The **Financial Module** is the first component of the integrated analysis of this program. The principal focus of the financial analysis is to see whether the program is financially feasible from an electric utility point of view.

The second module of the integrated investment appraisal is the **Economic Analysis**. The economic analysis of a program is concerned with the effect of the program on the entire society and determines whether the program increases the overall well-being of the society as a whole. For the economic analysis, all the costs and benefits associated with the program are converted into their economic values and included in the economic resource flow statement. The third component of the integrated investment appraisal is the **Stakeholder Analysis**. A stakeholder analysis is employed to identify the segments of the society that reap the benefits of the program and those that lose from the implementation of the program. The impacts are consequently quantified and measured in monetary terms.

A complete cost-benefit evaluation must also incorporate probabilistic risk and uncertainty analysis or a scenario analysis. The probabilistic approach allows the analyst to model uncertainties associated with parameters that affect project costs and benefits and assigns probabilities to them. Such risk and uncertainty analysis allow collecting and analyzing statistically the results of the simulations so as to arrive at a distribution of the possible outcomes of the program and the probabilities of their occurrence. A **Risk Analysis,** therefore, is performed to analyze the variability in the financial and economic returns of the program. A risk simulation is carried out as a part of the integrated appraisal approach.[55]

Hence, the net benefits are measured by comparing incremental costs and incremental benefits for <u>future</u> “with” the project to future “without” the project (i.e. “base” case). The following questions are relevant for the identification and distribution of such incremental costs and benefits.

1. *Identification of Impacts:* What are the incremental costs and incremental benefits associated with the project?

2. *Estimation (i.e. valuation) of Impacts:* How much are these incremental costs and incremental benefits?

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[55] Salci, S. and Jenkins, G.P. (2016); Jenkins et al. (2011), Chapter 6, Cost-Benefit Analysis for Investment Decisions.

3. *Allocation of Impacts:* Who will be the beneficiaries? And by how much will each pay or receive?

4. *Risk and Uncertainty Assessment:* What are the chances that the anticipated benefits and costs will be realized?

The project agreement has been signed between the Government of Haiti (representing electric utility in Haiti, EDH) and the donors providing the financing; Haitian Reconstruction Fund (HRF) and Inter-American Development Bank (IDB). Based on contractual agreement and nature of the investment, the project is evaluated from the perspectives of Electric Utility, EDH (Financial Analysis) and Society as a Whole (Economic Analysis). Using the integrated appraisal framework, the net benefits of the stakeholders will be estimated through a Stakeholder Analysis, and such net impacts will be distributed among relevant groups and externalities affected by the project (Distributive Analysis).

The identified program benefits and program costs are perceived and valued differently by the electric utility and society as a whole. The benefits and costs are priced at their market prices from the electric utility's point of view, whilst they are adjusted by the conversion factor to arrive their real economic worth. These economic values are used to estimate the impacts of the project on the economy as a whole. Note that cash/resource flow statements are presented in local currency. Thus, all foreign exchange transactions, in US$, are converted into their prices/costs in local currency, HTG.[56]

5.1 Financial Analysis

The financial module is the first component of the integrated analysis of this program. The principal focus of the financial analysis is to see whether the program is feasible from an electric utility point of view. The financial analysis of EDF helps us to understand the factors that affect the financial sustainability of the operation. The financial cash flow of the project is first conducted in nominal prices to account for the different effects of inflation. The nominal cash flow statement is then deflated, item by item, to arrive at the real cash flow statement.

5.1.1 Financial Benefits (Inflows)

The identified energy benefits of the project are: i) the production cost savings during off-peak hours, ii) incremental peak sales of energy during peak hours. These benefits are derived from incremental energy transmission coming from the 70 MW Hydro capacity. In addition to energy benefits, the rehabilitation will also generate revenues to the electric utility in the form of iii) avoided transmission capacity that is derived from incremental 10 MW Hydro capacity and valued at the long-run transmission charge per kWh). Finally, iv) the

[56] See Jenkins et al. (2011), Chapter 3 of Cost-Benefit Analysis for Investment Decisions.

residual values of the new transmission line capital assets are included as part of the utility benefits at the end of operational life. The financial benefits of the grants are attached to the program costs.

All inputs to calculate project benefits (oil prices, network charges for retail tariff) are expressed in US$ real terms, therefore, they are first converted to their nominal worth in US currency and then multiplied by the nominal exchange rate to arrive their nominal values in local currency. Finally, project benefits are estimated from these nominal prices and deflated by the domestic price index to get their real worth in HTG as of today.

1. Benefits of Incremental Energy Transmitted from 70 MW Hydro Power Plants (50 MW Peaking Load Plant *plus* 20 MW Baseload Planned Plant)

1A. Financial Value of Off-Peak Load Production Cost Savings

The financial benefits that accrue to the electric utility during the off-peak period are production cost savings from reduced use of the thermal plant. The production cost savings are composed of both variable fuel cost savings and variable operating and maintenance costs savings. With the same amount of off-peak load electricity generated from the 70 MW hydropower plant, the electric utility will be able to deliver (transmit) more grid energy during the off-peak load hours. The shaded area, labeled with a capital letter A, represents the total financial value of incremental production cost savings (see Figure 6).

Off-peak load energy cost savings are therefore dependent on: 1) the total kWh electric power actually displaced from the least-efficient diesel thermal generator by the total kWh incremental amount of power transmitted (horizontal distance of shaded area A), and 2) the marginal running cost (HTG/kWh) of the least-efficient generator running in the system (vertical distance of shaded area A).

The project is evaluated for 40 years, so the marginal running costs of thermal generators (HTG/kWh) cannot be treated as fixed numbers. The marginal fuel cost of generators is subject to fluctuations in oil price for electricity generation (HTG/liter) and the changes in the fuel efficiency of generation units (liter/kWh). Therefore, the monetary value of annual incremental energy cost savings (HTG) is calculated by multiplying the annual diesel fuel cost for electricity generation (HTG/liter) with the total annual liters of diesel fuel displaced (liters).

To do this, the incremental annual amounts of off-peak energy transmitted to the power network are first calculated; reflecting the transmission line efficiency gain from a lower rate of transmission line losses and a higher availability factor of the transmission line.[57] Secondly, the incremental off-peak energy transmitted, by the same amount (i.e. kWh to kWh), assumed to

[57] See Annex D, equation 7, and Annex D, Table D2.1.

displace energy from the least fuel-efficient generator running during off-peak load hours.[58] The kWh of displaced thermal energy is converted into fuel liters of fuel savings by multiplying them to its fuel consumption per kWh (liter/kWh).[59] Finally, the annual financial value of fuel savings is calculated by multiplying the fuel savings (liters) with the fuel cost for electricity generation (HTG/liter).[60]

The variable O&M cost component of the marginal generation cost is kept constant (US$/kWh). Therefore, the value of O&M costs savings is the product of the total kWh electric power displaced from the least-efficient (kWh) and O&M costs of the same plant (US$/kWh).[61]

Avoided expenditure on production costs, mainly fuel savings, is one the main benefits realized from the project. Fuel savings accounts for 30% of total benefits, excluding grants. (see Figure 7). The value of such savings will depend on the volume of oil displaced due to improved transmission efficiency and HFO price for electricity generation. Whereby, an increase in the real expected average price/volume of heavy fuel not purchased will improve the overall financial benefit of the project. The share of variable O&M costs represents less than 1% of all financial savings accrued to the electric utility.

1B. Financial Value of Incremental Peak-Load Utility Energy Sales

Under the assumption that consumers are willing to purchase incremental grid energy available during peak hours, the financial benefits will come from increased peak-load sales revenue. For the same amount of incremental peak-load electricity generated from 70 MW hydropower plants, the electric utility will be able also to deliver (transmit) more grid energy during peak load hours. The shaded area, labeled with a capital letter B, represents the total financial value of the incremental peak-load sales revenues (see Figure 6). These benefits are added as part of the increased peak-load sales revenue from the perspective of the electric utility.

The peak-load sales revenues are therefore dependent on 1) the total kWh incremental amount of electric power transmitted (horizontal distance of shaded area B), and 2) average electricity tariff (HTG/kWh) (vertical distance up to $\bar{P}_t^r$, of shaded area B). The future prices of electricity generation (HTG/kWh), reflected in retail prices, among many other factors, are also subject to fluctuations in oil prices (HTG/liter), future installations of new and possibly more efficient generation plants, the future changes in the fuel mix of power plants to generate electricity (liter/kWh) etc.[62]

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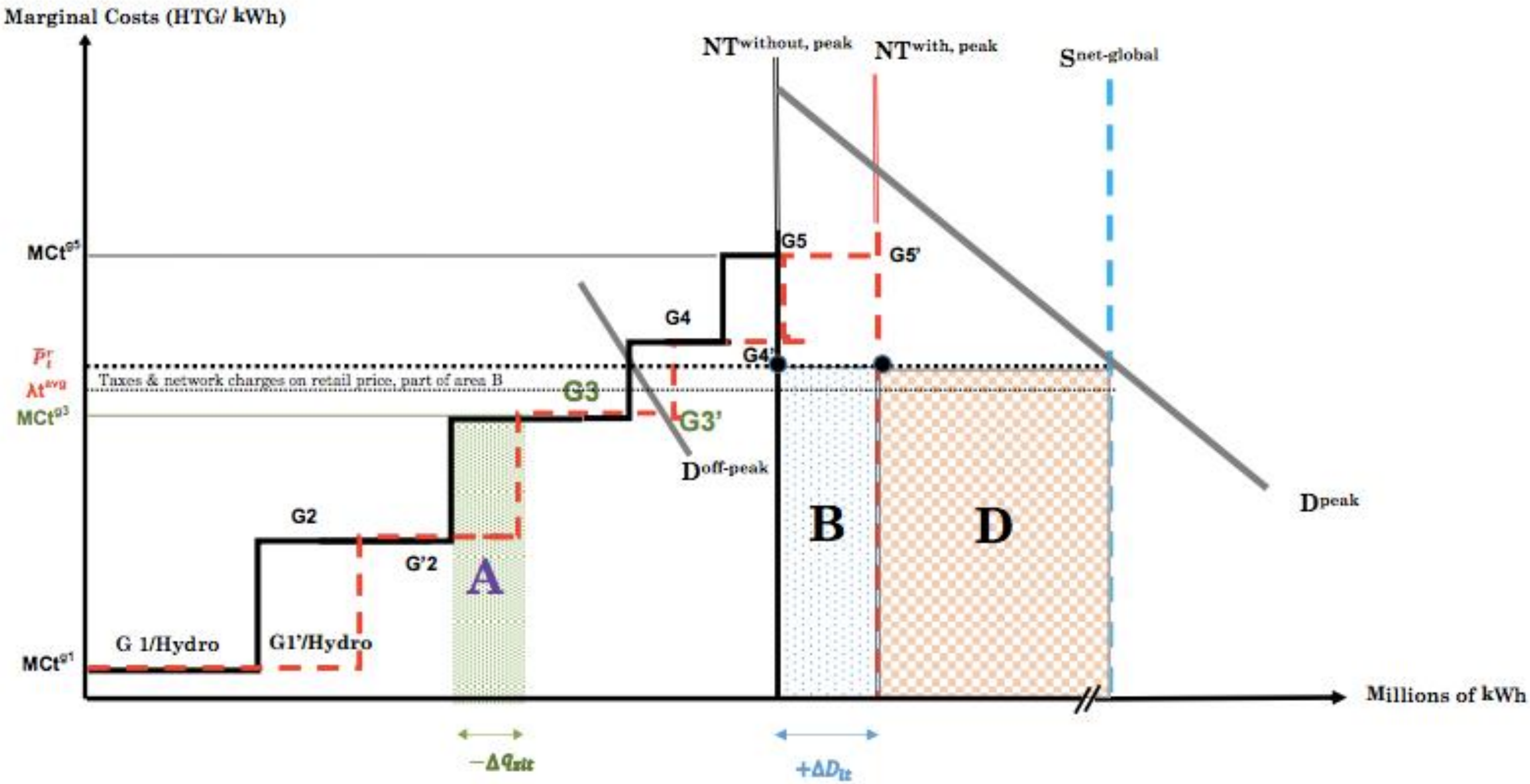
58 See Annex F, equation 11.
59 See Annex F equation 12.
60 See Annex F, equation 13.
61 See Annex F, equation 14.
62 See Annex E.

Figure 6. Financial Analysis of Improved Transmission Line Efficiency

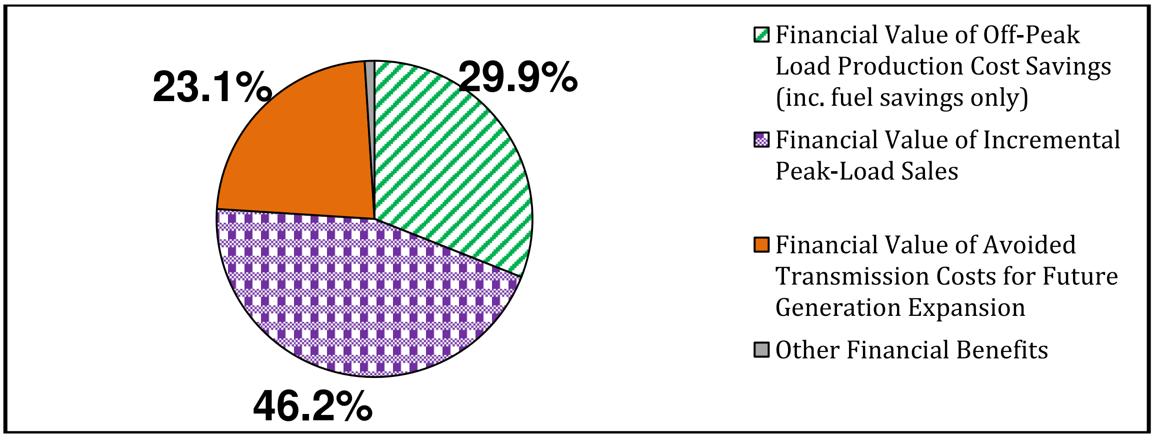


<u>*Source:*</u> own elaboration.

The total financial benefits accruing to the utility are estimated over the life of the project. First, the incremental annual amounts of peak energy transmitted to the power network are calculated. These reflect the transmission line efficiency gains from a lower rate of transmission line losses and a higher availability factor of the transmission line.[63]

The financial benefits of incremental peak energy are valued as the product of the resulting increased annual peak energy sales and the annual average tariff per kWh.[64],[65] The incremental peak-load sales revenues are the main benefit to the utility, accounting for 46% of the total financial benefits excluding grant contributions. The value of incremental peak-load sales revenue depends on the volume of additional energy transmitted from reduced transmission losses (kWh) and the annual average retail electricity charge (HTG/kWh). Second, there are generation costs savings from the incremental off-peak energy transmitted.[66]

Figure 7. Shares of Financial Economic Benefits, % of Total Financial Benefits*



Source: extracted from the model. (*) excluding grant contributions.

2. Financial Value of Transmission from Additional 10 MW Hydro Generation Capacity

The incremental net energy from the additional 10 MW of generation is calculated, subject to line losses and availability of the rehabilitated line.[67] The financial benefits from additional generation capacity are valued at long-run transmission charge per kWh (γ), reflecting benefits of the transmission line as being a stand-alone (individual) project.[68] The fixed long-run average transmission line charge is priced at 0.02 US$/kWh.

[63] See Annex D, equation 7, and Annex D Table D2.2.
[64] See Annex F, equation 16.
[65] Area D on figure 6 represents utility revenues from future generation expansion. They are not part of incremental revenues from transmission line. At the same time, transmission permits maximum generation capacity at 80 MW.
[66] See Annex F, equation 14.
[67] See Annex D, equation 8 and Annex D Table D3.1.
[68] See Annex F, equation 17.

At this transmission price per kWh, the financial value of transmission cost avoided represents roughly 23% of the total financial benefits.

3. Financial Residual Value of "New" Transmission Assets

The existing (unimproved) transmission line assets (i.e. equipment, conductors, etc.) have no direct or indirect alternative use value, so the residual benefits of these assets "without" project scenario are equal to zero. The residual values of new assets are calculated using straight-line depreciation method, assuming no major capital replacements for the duration of the project. The economic life of underground and overground conductors, transmission materials are 55 years. The project is evaluated for an operating life of 40 years; assets are valued at their book value in the year 2058.

4. Financial Benefits of Grants

The grants are included in the financial benefits (i.e. inflows) because the donors are paying for program costs. These grants are attached to investment costs on transmission rehabilitation. Therefore, the investment costs associated with the program are included in the financial costs (i.e. outflows). Note that the amounts of grants are just equal to investment costs of the program. The value of these grants will increase by the same amount if investments cost increase, and it is subject to cost-over-run factor.

5.1.2 Financial Costs (Outflows)

Because grants are provided for utility investment for transmission rehabilitation. The investment costs are deducted as outflows of the cash flow statement. The investment costs associated with the project are (i) transmission line capital costs as part of technical costs (ii) resettlement and compensation costs of inhabitants, firms and farmers, (iii) direct labor costs. These investment costs are estimated at US$ (see Table 3).

In addition to program investment costs, the total incremental operation and maintenance expenses are included as part of outflows of the electric utility (see Table 4). Electric Utility (EDH) pays for them. Thus, they are not included as part of grant funding. All costs except labor costs are expressed in US$ real terms, therefore, they are first converted to their nominal worth in US currency and then multiplied by the nominal exchange rate to arrive at their nominal costs. Finally, deflated by the domestic price index to get their real worth in HTG as of today.

Incremental peak-load sales revenues from the utility's supply of electricity are calculated using the retail price of electricity (HTG/kWh); therefore, they are gross of taxes. The Electric Utility (EDH) collects these incremental taxes, and is transferred to the government's budget. Therefore, sales taxes are part of outflow from the utility's point of view.

Table 8. Annual Cash Flow Statement from Electric Utility Point of View (Real, Millions of HTG)

FINANCIAL CASH FLOW STATEMENT - ELECTRIC UTILITY POINT OF VIEW (REAL)		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
INCREMENTAL BENEFITS (INFLOWS)															
Production Cost Savings During Off-Peak Load Hours															
Financial Value of Fuel Savings	*Million HTG*	0	0	0	0	43	89	...	93	...	96	...	97	...	0
Financial Value of O&M Cost Savings	*Million HTG*	0	0	0	0	1	1	....	1	....	1	....	2	....	0
Incremental Energy Delivered for Peak-Load Consumption															
Gross Financial Value of Incremental Peak Load Sales Revenue	*Million HTG*	0	0	0	0	92	124	...	141	...	156	...	170	...	0
Value of Incremental Transmission Capacity from Additional 10 MW Hydro Capacity															
Financial Value of Avoided Transmission Costs for Future Generation Capacity Additions	*Million HTG*	0	0	0	0	0	74	...	74	...	74	...	74	...	0
Value of Incremental Peak/Off-Peak Energy & Avoided Transmission Benefits	*Million HTG*	**0**	**0**	**0**	**0**	**136**	**289**	...	**309**	...	**327**	...	**343**	...	**0**
Residual Values															
Liquidation Value of Transmission Line Assets	*Million HTG*	0	0	0	0	0	0	...	0	...	0	...	0	...	294
Grants															
Total Investments Grants, by Haiti-Reconstruction Fund (HRF)	*Million HTG*	147	181	215	317	0	0	...	0	...	0	...	0	...	0
Total Investments Grants, by Inter-American Development Bank (IDB)	*Million HTG*	64	85	107	171	0	0	...	0	...	0	...	0	...	0
Residual Value of Transmission Assets + Grants	*Million HTG*	**211**	**266**	**322**	**488**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**294**
TOTAL INCREMENTAL CASH INFLOW (+)	*Million HTG*	**211**	**266**	**322**	**488**	**136**	**289**	...	**309**	...	**327**	...	**343**	...	**294**
INCREMENTAL COSTS (OUTFLOWS)															
Investment Costs															
Sub-Component A - Transmission Line Physical Investment Costs															
Supplies of Conductors, Equipments and Materials - Overground Line	*Million HTG*	83	111	139	223	0	0	...	0	...	0	...	0	...	0
Supplies of Conductors, Equipments and Materials - Underground Line	*Million HTG*	51	68	85	135	0	0	...	0	...	0	...	0	...	0
Equipment and Supplies for Repairs, Substation and Civil Works	*Million HTG*	16	21	27	42	0	0	...	0	...	0	...	0	...	0
Insurance, and Handling and Transport Services	*Million HTG*	4	6	7	12	0	0	...	0	...	0	...	0	...	0
Sub-Total	*Million HTG*	**155**	**206**	**258**	**412**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**0**
Sub-Component B - Resettlement and Compensation Costs															
Land Acquisisation and Housing Costs	*Million HTG*	4	5	6	9	0	0	...	0	...	0	...	0	...	0
Compensation of Farmers and Land Owners	*Million HTG*	2	2	3	5	0	0	...	0	...	0	...	0	...	0
Compensation of Businesses	*Million HTG*	2	2	3	5	0	0	...	0	...	0	...	0	...	0
Administration, Management and Monitoring Costs	*Million HTG*	3	4	5	7	0	0	...	0	...	0	...	0	...	0
Sub-Total	*Million HTG*	**10**	**13**	**17**	**26**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**0**
Sub-Component C - Direct Labour Costs															
Skilled Labour Costs	*Million HTG*	20	20	20	21	0	0	...	0	...	0	...	0	...	0
Semi-Skilled Labour Costs	*Million HTG*	12	12	13	13	0	0	...	0	...	0	...	0	...	0
Total Direct Unskilled Labor Cost	*Million HTG*	14	15	15	15	0	0	...	0	...	0	...	0	...	0
Sub-Total	*Million HTG*	**46**	**47**	**48**	**49**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**0**
Total Investment Costs	*Million HTG*	**211**	**266**	**322**	**488**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**0**
Additional Operating Costs															
Total Incremental Operation and Maintenance Expense paid by Electric Utility	*Million HTG*	0	0	0	0	0	0	...	0	...	0	...	0	...	3.3
Total Incremental Cash Outflow	*Million HTG*	**211**	**266**	**322**	**488**	**0**	**0**	...	**0**	...	**0**	...	**0**	...	**3**
NET INCREMENTAL CASH FLOW - BEFORE TAXES	*Million HTG*	**0**	**0**	**0**	**0**	**136**	**288**	...	**309**	...	**327**	...	**343**	...	**291**
Taxes on Peak Energy Sales															
Incremental Utility Taxes on Peak Energy Sales	*Million HTG*	0.00	0.00	0.00	0.00	3.07	4.11	...	4.57	...	4.95	...	5.25	...	0.00
NET INCREMENTAL CASH FLOW - AFTER TAXES	*Million HTG*	**0**	**0**	**0**	**0**	**133**	**284**	...	**305**	...	**322**	...	**337**	...	**291**

Economic Opportunity Cost of Kapital (EOCK)	8%	%
Financial NPV (Electric Utility, EDH)	**2,763**	*Million HTG*
Real Exchange Rate (HTG/US$ - year 0)	55	#
Financial NPV (Electric Utility, EDH)	**50.2**	*Million US$*

5.1.3 EDF Financial Feasibility

From the perspective of the electric utility, the incremental financial cash-flow statement is presented in Table 8. The present value of the discounted net financial cash flow over the life of the project should not be less than zero. Table 8 shows that the financial NPV of the project is HTG 2,763 million (equivalent to US$ 50.2 million), using a real discount rate of 8%. The utility's return from the project is almost twice as larger as the cost of the program. Note that this project is being financed by a grant. However, if EDH were a well-functioning utility, this transmission project could be financially justified on a commercial financing basis.

Clearly, the positive net cash savings and earnings of the electric utility from this improvement in the transmission line will contribute to servicing its accumulated debts. In the long run, the returns gained by the EDH might help to finance additional system expansion or allow the Haitian government to allocate more from its budget for the poverty reduction programs or social services.

5.1.4 Financial Sensitivity Analysis of Project

A sensitivity analysis is carried out by altering the values of key input variables and the assumptions that underpin the estimated costs and benefits. This process is repeated for each of the input variables expected to have a large impact on outcomes. The changes in the projected key outputs of the analysis are then recorded according to the changes made in the value of the input variables, holding all other input variables constant. A number of sensitivity tests are carried out to identify critical parameters affecting the project's performance. This section lists the most important risk/uncertain parameters identified during the analysis. These risk/uncertain parameters are examined further in the risk simulations.

L-R Average Real International Price of Crude Oil (US$/bbl)

The electric utility saves fuel during off-peak load, whose selling price is closely linked to the price of crude oil on the international market. The long-run marginal costs of electricity generation from fuel plants will be greater if the average real crude oil price is higher than the assumed real average price of 50 US$/bbl. The higher (lower) expected real average long-run crude oil price from the beginning of the project would have a positive (negative) impact on the value of fuel savings due to the reduction of transmission losses. Needless to say, the retail cost of electricity production with a higher expected long-run average oil prices would have to increase, regardless of the savings the project generates. The Electric Utility (EDH) will sell incremental electricity during peak-load hours at the retail prices reflecting the changes in the production costs. Therefore, utility peak-load sales revenue from the incremental sales will also increase.

Table 9 shows that if future real average crude oil price is 5 US$/bbl above or below its assumed level of US$/bbl 50, the financial NPV of the project rises or falls by HTG 166 million (equivalent to US$ 3 Million). This is an indicator that, the real average price of crude oil has a significant impact on the financial performance of the project. However, changes in prices of the magnitude that are likely to occur will not threaten the financial viability of the project from the perspective of the electric utility.

Table 9. Financial Sensitivity Test of L-R Average Real Price of Crude Oil (US$/bbl)

	NPV Financial Analysis (Millions of HTG)
35	2,265
40	2,431
45	2,597
50	**2,763**
55	2,929
60	3,095
65	3,261

L-R Equilibrium Real Exchange Rate (%)

Production cost savings and incremental peak-load sales are both linked to the long-run average real crude oil price (US$/bbl). The long-run average transmission price of electricity is also expressed in US$. The nominal prices of crude oil and transmission prices are both expressed in HGT by using the nominal exchange rate between HTG and US$. Furthermore, the nominal exchange rate is derived from the real exchange rate multiplied by the relative price indices of the two countries.

Table 10. Financial Sensitivity Test of L-R Average Real Exchange Rate (%)

	NPV Financial Analysis (Millions of HTG)
-4.0%	2,653
-2.0%	2,708
0.0%	**2,763**
2.0%	2,819
4.0%	2,874

In the calculations of financial benefits, the prediction error in the real exchange rate is assumed to be 0%. As the real exchange rate increases fuel prices in local currency will increase, hence increasing the utility savings from reduced transmission losses. It will also be reflected in the retail price of electricity. Utility sales revenue will rise because of the increase in the nominal electricity tariff. Hence, the project's financial NPV will increase, as shown in Table 10.

Investment Costs Overrun (%)

Cost overruns are the differences between the actual costs upon realization of the project and the initial estimated investment costs. An escalation of the investment cost will not lead to a financial loss from the electric utility's point of view, as the monetary value of grants is directly attached to the investment costs of the project.

Table 11. Financial Sensitivity Test of Investment Costs Overrun Factor (%)

	NPV Financial Analysis (Millions of HTG)
-15%	2,762
-10%	2,762
-5%	2,763
0%	**2,763**
5%	2,764
10%	2,764
15%	2,765

Discount Rate (%)

The required rate of return for a public electricity utility is the rate that allows the utility to cover costs of operations and earn a "fair" return to invest on expansions to meet demand growth. Setting a high rate of return on its operations would imply that pricing of the services provided by the public utility would have to be adjusted upward, thus hurting the consumers. The electric utility in Haiti has its operations largely financed by government funds and donor grants. Hence, it is difficult to determine what is the appropriate target rate of return to use as the financial discount rate in this analysis.

Table 12. Financial Sensitivity Test of Discount Rate (%)

	NPV Financial Analysis (Millions of HTG)
6%	3,765
7%	3,209
8%	**2,763**
9%	2,402
10%	2,105

Table 12 shows that the impact on the financial NPV for changes in the exchange rate. If the discount rate is reduced from 8% to 7%, the financial NPV of the project rises from HTG 2,763 million (equivalent to US$ 50 Million) to HTG 3,209 million (equivalent to US$ 58 Million). The selected discount rate has an important impact on the financial NPV of the electric utility, as shown by the results of the sensitivity analysis reported in Table 12.

5.2 Economic Analysis

The second module of the integrated investment appraisal is the **Economic Analysis**. The economic evaluation of a project measures the effect of the project on the entire society and determines if the project increases the total net economic benefits accruing to the society as a whole. The economic appraisal translates all financial transactions (i.e., receipts and expenditures) into economic benefits and costs to reflect their value to society. An important feature of the integrated appraisal framework is that the economic evaluation is directly linked to the financial model of the project.[69] The linkage of the financial and economic analysis allows the analyst to make sophisticated inquiries into the project's financial and economic performance at the same time.

The relationship between the financial and economic value of a particular good or service is called a Commodity Specific Conversion Factor (CSCF). A CSCF is calculated as the rate of the economic value over the financial price of an item. In general, the economic values of all tradable goods (e.g., fuel purchases, capital items) are estimated free of distortions such as import duties, taxes, and subsidies. Nevertheless, it should include the foreign exchange premium (FEP) due to the presence of the various distortions in the markets for tradable goods and services. Similarly, the shadow prices of non-tradables are estimated at prices free of distortions and inclusive of thenon-tradable premium (NTP). The tax distortions, FEP and NTP estimates are all assumed to be the same throughout the project's life, implying a constant CSCF for them.[70]

The economic value of all inputs used and outputs produced by the project are estimated, and the resulting economic conversion factors are summarized in Table 13 below. Multiplying these conversion factors by the corresponding cashflow items in the financial statement of the project will enable one to arrive at the economic costs and benefits of the investment.

Apart from the prices estimated in the financial model of the overall scheme, a number of economic assumptions and parameters are necessary for the economic analysis. Before discussing the estimation of the economic values of the project's costs and benefits, the following parameters and assumptions have been defined.

[69] See Jenkins et al. (2011), manual chapters including Chapter 7 & Chapter 8.
[70] See Jenkins et al. (2011), manual chapters including Chapter 9, Chapter 10 & Chapter 11.

Table 13. Conversion Factors for Economic Analysis

BENEFITS	CF
Production Cost Savings During Off-Peak Demand Load	
Value of Fuel Savings (i.e. Production Cost Savings)	0.994
Value of O&M Cost Savings	0.964
Incremental Energy Delivered During Peak Demand Load	
Value of Peak Load Sales (i.e., reduction in own-generation costs)	No CF
Avoided Transmission Capacity for Future Expansion	
Avoided Transmission Capacity Costs	1.027
Residual Values	
Residual Value of New Overground/ Underground Line Assets	1.027
Environmental Benefits	
Social Benefits of Emission Reduction	No CF
Grants	
Investment Cost Paid by Haiti Reconstruction Fund (HRF), means of Grant	0.00
Investment Cost Paid by Haiti Reconstruction Fund (IDB), means of Grant	0.00
COSTS	
Investment Costs	
Sub-Component A – Transmission Line Investment Costs	
Overground Transmission Equipment	1.027
Underground Transmission Equipment	1.027
Equipment and Supplies for Repairs and Substation and Civil Works	0.964
Insurance, Handling, and Transportation of Capital Equipment	1.046
Sub-Component B – Resettlement Costs and Compensations	
Land acquisition and Housing Construction Costs	0.901
Compensation of Farmers and Land Owners	1.00
Compensation of Businesses	1.00
Administrative and Management Costs for Resettlement Work	1.00
Sub-Component C– Direct Labor Costs	
Skilled Labor	0.932
Semi-Skilled Labor	0.883
Unskilled Labor	0.700
Additional Operating Costs	
Incremental Operation and Maintenance Expense paid by Electric Utility	0.964
Taxes	
Incremental Utility Taxes on Peak Energy Sales	0.00
Taxes on Fuel for Own Generation	No CF[71]

Source: extracted from feasibility model.

71 CF of taxes is zero. Because the economic benefits of peak load sales are valued at the marginal cost of own generation, taxes were deducted in economic analysis in order not to overstate the total value of the economic benefits. As peak load sales from the utility will substitute self-generation, they are priced at electricity tariff from the electric utility point of view (i.e. financial analysis). The electricity tariff cannot capture the economic benefits, and the financial analysis does not include consumers' benefits. The adjustment made in this analysis will capture the net benefits to consumers as well as net fiscal impacts in the form of Gov't tax gains/losses. Also, both marginal coping costs for unreliable power supply and electricity tariff are time dependent. Hence, the use of a constant CF would be conceptually wrong, and tax impacts move on opposite direction from peak utility sales (tax gain for Gov't of Haiti) and reduced self-generation (tax loss for the Gov't of Haiti).

5.2.1 Parameters / Approach for Economic Analysis[72]

<u>*National Economic Parameters*</u>

The economic cost of capital (EOCK) reflects the real rate of return forgone in the economy when resources are shifted out of the capital market. Because aid flows are huge and uncertain, it is very difficult to know what is the opportunity cost of such funds. The results are sensitive to the choice of discount rate. For this appraisal, The EOCK for Haiti is assumed to be 8%.

The **foreign exchange premium (FEP)** is estimated to be 5.75% higher than the market price of foreign exchange for the country (Kuo, 2016). This foreign exchange premium is used to calculate the economic costs and benefits of the tradable goods and services.[73]

The **premium on non-tradable outlays (NTP)** is estimated to be at 0.75% (Kuo, 2016). Hence, the the ecoomic values for non-tradable outlays is somewhat higher than the corresponding financial outlays.

The Economic Opportunity Cost of Labor (EOCL) is estimated using the supply price approach. This approach starts with the wage paid by the project and makes all the necessary adjustments with regard to income taxation as well as social security contributions to arrive at the EOCL. The personal income taxes are 25% and 15% for skilled and semi-skilled labor, respectively. According to the income tax rules in Haiti, the earnings of unskilled labor fall into the zero income tax bracket. It is assumed that in the absence of this project, skilled, semi-skilled and unskilled labor would have spent 90%, 70% and 50% of their time employed elsewhere, respectively. The earnings of skilled labor from alternative employment would be 60,000 HTG/year, semi-skilled would be 30,000 HTG/year, and unskilled would be 8,000 HTG/year.

The **average effective rate of indirect taxes *(d*)*** on tradable and non-tradable goods and services in the country is estimated at 4%. This parameter is used in the calculation of economic conversion factor of non-traded goods.

The **social cost of carbon** is used for monetizing the environmental benefits in the form of a reduction in carbon emissions, and average priced at 20 US$/ton based on a meta-analysis.[74] The average carbon emission intensity of HFO and diesel oil is 2.31 kg/liter, and 2.68 kg/liter, respectively.

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[72] See Annex G.

[73] The difference between the economic foreign exchange rate and the market exchange rate can be expressed as a proportion of the market exchange rate. It is referred to as the foreign exchange premium (FEP). The FEP captures all domestic and international taxes and distortions associated with tradable items, so it captures the changes in the welfare in a country from foreign exchange payments that are paid and/or earned. For more information, see Kuo, Salci and Jenkins (2015).

[74] See Greenstone et al. (2013).

The **marginal cost of self-electricity generation** (HTG/liter) is calculated from an average diesel fuel consumption of small diesel generators (liters) plus the fixed capital charges. Based on the available evidence, the diesel fuel consumption of a small diesel generator is set at 0.404 liter/kWh and assumed to be declining at a rate of 0.5% every year. The fixed capital charge is calculated at 0.02 US$/kWh and it is assumed to remain constant over time.[75]

Import Duties, Taxes, and Other Charges

Imported capital items are not subject to any import duty or VAT. These capital items include transmission line equipment, conductors, cables and its related costs as well as other costs (see sub-component (a) of the program costs, Table 3). The **handling and transport services**, for both imported capital items and fuel imports, are exempted from domestic VAT and other local taxes. **Infrastructure, substation and civil works** are non-tradable inputs of the project and are also exempted from domestic taxation.

Beginning with the crude oil price, adjustments are made for the refinery charges and international transport charges to arrive at the domestic price (CIF price) for diesel fuel for electricity generation. The excise taxes are 6% on petroleum products. For the cost of own-electricity generation, diesel prices are 40% higher than the price of diesel purchased by the electric utility.[76]

Approach for the Economic Benefits from Transmission Rehabilitation

1) The economic valuation of incremental off-peak and peak load transmission benefits from the 70 MW hydro project are as follows:

> 1A) The economic value of off-peak production cost savings are made up of fuel savings and the O&M costs savings from the least-efficient plant running at that time. Fuel savings and O& M cost savings are both valued at their economic price, therefore they are adjusted for taxes and foreign exchange premium. Oil specific and O&M cost specific conversion factors are used to derive their economic worth.
>
> 1B) The assessment of incremental peak-load sales is assumed to displace equal amounts of energy from private generators. Peak load savings are comprised of fuel and capital cost savings, of own generation (i.e. marginal cost of own-generation per kWh).[77]

2) The economic valuation of incremental off-peak and peak load transmission from additional 10 MW hydro capacity is valued at the average (and marginal)

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75 Capital costs account for about 10% of the marginal cost of self-generation. See Annex H.
76 See Annex H.
77 Note that results from the economic analysis will not change if you calculate peak load savings based on the cost of fuel per liter. For such analysis, you will need to estimate liters of fuel saved from self-generation, and then multiply the liters of fuel with the cost of fuel purchase. Similarly, tax losses from the perspective of government can be calculated from the difference in fuel purchase with and without tax.

long-run transmission cost per kWh. The conversion factor is used to value the economic benefits of avoided transmission investments for future generation expansion.

3) Residual values of new transmission assets are valued at their economic worth by the end of the project's operational life (i.e., the year 2058).

4) Grants are transfers from other projects, therefore, are not included in the economic benefits (i.e. CF=0).

5) Environmental benefits in the form of reduced emissions are valued at the social cost of carbon. To get an actual contribution to residents in Haiti, the total environmental impacts are first estimated and then adjusted by multiplying them by 0.001, under the assumption that Haiti would receive about 0.1% of the global benefits of greenhouse gas reductions created by the project.[78]

5.2.2 Economic Benefits (Resource Inflows)

As outlined in the previous section, the incremental economic benefits of the project are (i) the production cost savings during off-peak hours, (ii) the reduction in own-generation costs during peak hours, iii) the economic benefits of avoided transmission costs for future expansion, iv) the residual values of the capital assets, and v) societal benefits of carbon emissions.

1. Economic Benefits Incremental Energy Transmitted from 70 MW Hydro Plants (50 MW Peaking Load plus 20 MW Baseload Planned Plant)

1A. Economic Value of Off-Peak Load Production Cost Savings

The economic benefits accrue during the off-peak period are production cost savings, composed of fuel cost savings and O&M expenses from reduced use of thermal plants. When estimating the economic value of such production cost savings, their financial values (shaded area A, Figure 8,) are adjusted by multiplying it with the fuel oil specific conversion factor and O&M expense specific conversion factor.[79]

The Commodity Specific Conversion Factors (CSCF) for oil and O&M expenses are estimated at 0.994 and 0.964, respectively. Therefore, (i) the economic benefits of production cost savings are less than the financial value of such savings for the electric utility, reflecting the tax losses by the government.

One of the main benefits of the project is the generation cost savings (mainly fuel savings), which accounts for 25% of the total economic benefits from the project (See figurer 9).

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78 From the global economy point of view, all environmental benefits are part of benefits.
79 See Annex I, equation 21 & equation 22.

1B. Economic Value of Peak-Load Reduced Self-Electricity Generation

The economic benefits during peak hours of operation will come from incremental grid energy transmitted to consumers. During peak-load hours, the additional grid energy will reduce consumption of energy from self-generation of power. In other words, the electric utility will be able to substitute for some of the peak energy previously produced by own-generation sources.[80] In the case of the output of electricity sold during peak-load hours, a conversion factor is not estimated as it is not directly related to the financial tariff to be charged in the future. The economic benefits are valued based on the resource cost savings from the perspective of consumers. Therefore, they are estimated using the marginal cost of own-electricity generation (HTG/kWh).[81]

In figure 8 the shaded areas, labeled with a capital letter B plus C (excluding taxes), represents the total economic value of the incremental peak-load sales revenues. The economic value of additional peak-load sales are therefore dependent on 1) the total incremental amount of electric power transmitted (horizontal distance of shaded area B+C), and 2) the average marginal cost (HTG/kWh) of the own- generation in a year (vertical distance up to $\overline{MC}_t^{own}$, of shaded area B+C)[82]. The total incremental amount of electric power transmitted, is just equal to kWh of self-generation reductions.

The marginal cost of self-generation is not a static number. It will also fluctuate with the oil price for own electricity generation (HTG/liter) it is subject to the changes in the fuel efficiency of self-generators over-time (liter/kWh). Therefore, the marginal cost (HTG/kWh) of the self- generation is calculated on an annual basis, by multiplying annual diesel fuel cost for own electricity generation (HTG/liter) with the average number of liters of diesel fuel consumption required per kWh of own-generation.[83]

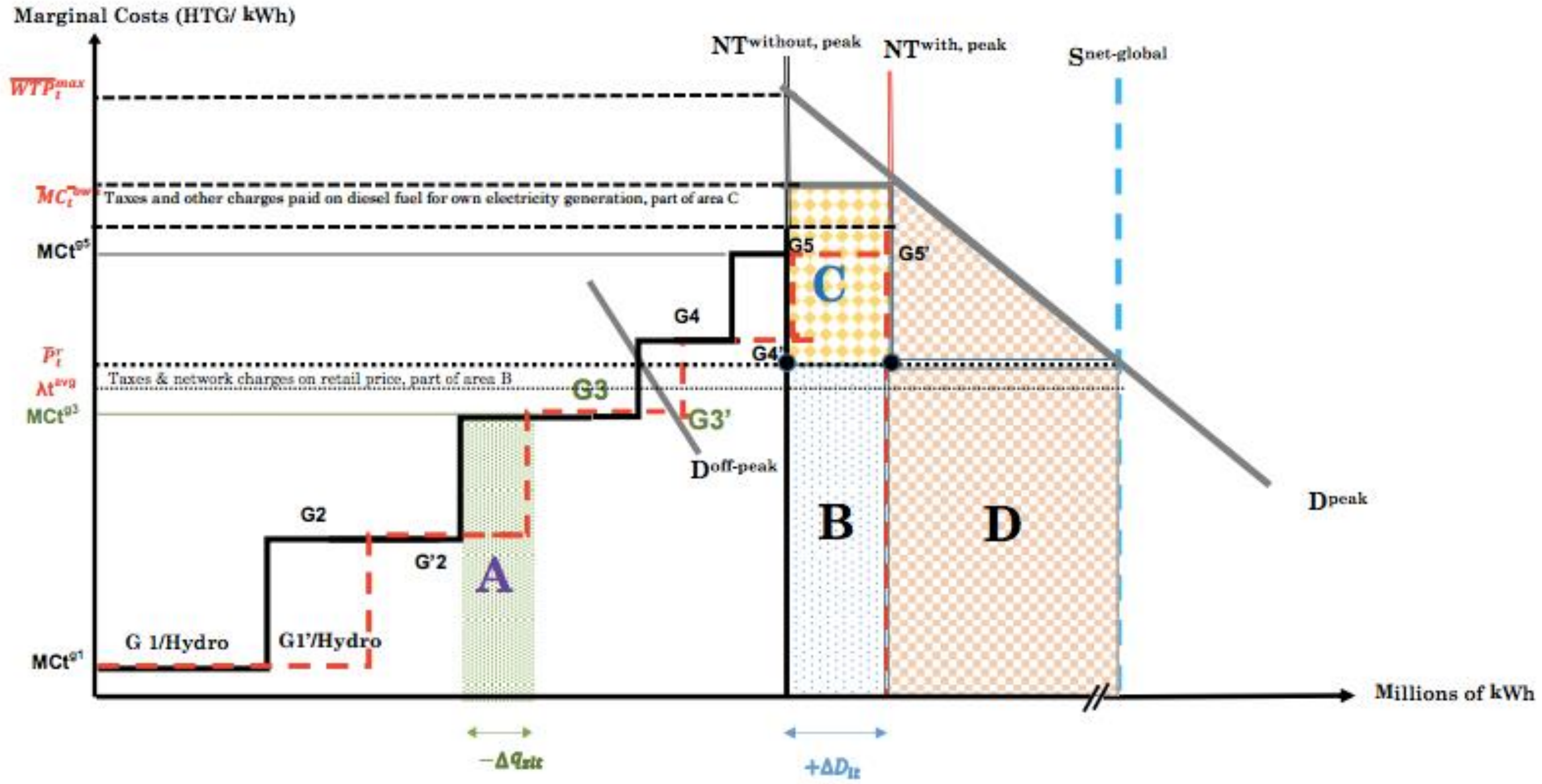
[80] See Annex I, equation 23.

[81] See Annex I, equation 24.

[82] The transmission line project alone will not eliminate the reliability associated with the energy supply. Hence, the marginal cost of self- generation will be used to calculate the economic benefits accrued during peak-load hours. The calculation of maximum willingness-to-pay is useful to estimate the economic benefits of future investments in generation, which represent the total energy required (see area D, Figure 8). Supply global represents the amounts of energy (therefore future investments in generation capacity) required to eliminate reliability problem in Haiti. The size of area D relative to the total size of area B is very large.

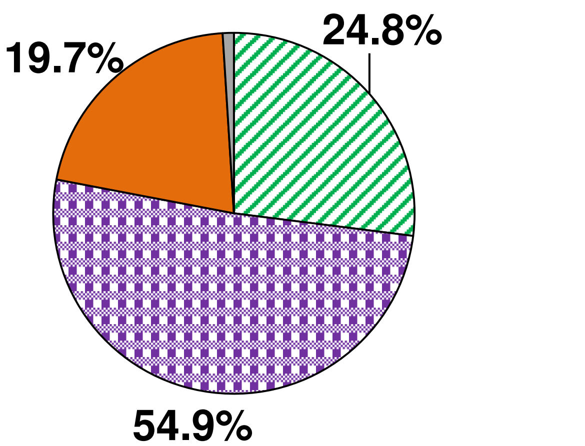
[83] Note that results from the economic analysis will not change if you calculate peak load savings using estimates on the private cost of fuel per liter. For such analysis, you will need to estimate liters of fuel saved from self-generation {= peak load energy delivered to consumers (kWh) times the average fuel consumption per kWh from privately owned small generators (liter/kWh)} and then multiplying this number with the cost of fuel purchase by the private consumers (HTG/liter).

Figure 8. Economic Analysis of an Improved Transmission Line Efficiency



Source: own elaboration.

Figure 9. Shares of Project Economic Benefits



<u>*Source:*</u> extracted from the model.

The average price of diesel fuel for self-generation and the average fuel consumption of these small diesel generators are both higher than their values for utility level electricity generation. Hence, the marginal cost of own generation is significantly higher than peak load sales revenue earned by the electric utility.[84] The main benefit of the project is the reduced peak-load self-generation, it accounts for 55% of the total economic benefits accrued due to the project (see figure 9).

3. Economic Value of Transmission from Additional 10 MW Hydro Generation Capacity

The economic value of incremental energy transmitted from additional generation capacity is calculated using the CF for transmission assets and included as part of the resource inflow.[85] The CSCF of the residual value of new overground / underground line assets is used for estimating the economic value of the avoided transmission costs. Its value is 1.027 implying that the economy-wide benefits are slightly larger than the utility level benefits. These benefits account for about 20 % of the total economic benefits accruing to the project (see figure 9).

4. Economic Value of Reduced Emissions from Electricity Generation

The emission benefits come from HFO displacement by the utility during off-peak load hours and diesel oil displacement by the private consumers during peak load hours. The annual emission savings are initially calculated by

[84] The gap between the MC of self-generation and the electricity tariff would be smaller if the utility electricity pricing would follow peak-load retail electricity pricing. Given the complexity of such pricing applications, static peak-load pricing in the form of time-of-use pricing (TOU) would be a better option in PAP metropolitan network. The current status of the network does not permit for such time-differentiated pricing, and it is possible in long run when operations of the electric utility are well-functioning.
[85] See Annex I, equation 25.

multiplying the fuel savings during peak load and off-peak (liters) loads with the fuel specific carbon emissions (kg/liter).

The annual carbon emissions are converted from kgs to tons as the social cost of carbon is expressed in US$/ton.[86] At the stated social cost of carbon (US$/ton), such benefits are estimated and included as part of local economic benefits. Since the economic analysis includes the impacts on the local economy, such benefits are multiplied by 0.1% to capture its benefits to locals in Haiti.[87] Because the economic analysis includes impacts on the local economy, such global benefits accruing to Haiti are computed at 0.1% of the total global value of the reduction in GHG brought about by the project.[88]

5. Economic Value of Grants

The grants are excluded in the economic benefits (i.e. inflows) because the donors are paying for them. Such funds are transferred from "other projects in Haiti that could have been funded" to this transmission project. Hence, the difference between economic values of grants (value of CF=0) and financial values of grants will give us the value of the resources released from other projects to finance the transmission project.

5.2.3 Economic Costs (Resource Outflows)

From the electric utility point of view, the investment and operating costs associated with the project are reported as nagetive values in the resource flow statement. The economic costs of the project are adjusted with their conversion factor to arrive at their true economic costs to Haiti (see Table 13).

The marginal cost of self-generation is inclusive of taxes paid on fuel purchases. The monetary values of these taxes are calculated by subtracting all taxes & other charges from the marginal cost of self-generation and multiplying the value (HTG/kWh) by the total incremental amount of electric power transmitted during peak load hours.[89] The amounts of taxes lost from reduced self-generation are the revenue losses of the government (see rectangle within area C, Figure 8). The incremental taxes that are collected by the utility are included as part of outflow from the utility's point of view and a CF of 0 is applied to the financial amounts in the economic analysis.

[86] See Annex I, equations 26-28.
[87] Included as part of benefits to electricity consumers. The share of emission reductions benefits are less than 1% of all benefits to the economy.
[88] From the global point of view, emission reduction benefits will include 100% of all environmental benefits.
[89] Note that the tax losses from the perspective of government can be calculated from the difference in fuel purchase with and without tax, see footnote 68.

Table 14. Annual Resource Flow Statement from Economy Point of View (Real, Millions of HTG)

ECONOMIC RESOURCE FLOW STATEMENT – COUNTRY (HAITI) POINT OF VIEW (REAL)		CF	2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
INCREMENTAL ECONOMIC BENEFITS																
Production Cost Savings During Off-Peak Load Hours																
Economic Value of Fuel Savings	*Million HTG*	0.994					43	89	...	92	...	95	...	97	...	
Economic Value of O&M Cost Savings	*Million HTG*	0.964							...		...		...	2	...	
Incremental Energy Delivered for Peak-Load Consumption																
Value of Reduced Peak-Load Self Generation Costs (i.e. private consumers)	*Million HTG*	*NO CF*					131	176	...	201	...	224	...	244	...	
Value of Incremental Transmission Capacity from Additional 10 MW Hydro Capacity																
Economic Value of Avoided Transmission Costs for Future Expansion	*Million HTG*	1.03						76	...	76	...	76	...	76	...	
ECONOMIC VALUE OF PEAK LOAD AND OFF-PEAK LOAD ENERGY/TRANSMISSION BENEFIT	*Million HTG*						174	342	...	371	...	396	...	418	...	
Residual Values																
Liquidation Value of Transmission Line Assets	*Million HTG*	1.03							...		...		...		...	302
Grants																
Total Investments Grants, by Haiti-Reconstruction Fund (HRF)	*Million HTG*	0	0	0	0	0	0	0	...	0	...	0	...	0	...	0
Total Investments Grants, by Inter-American Development Bank (IDB)	*Million HTG*	0	0	0	0	0	0	0	...	0	...	0	...	0	...	0
Residual Value of Transmission Assets + Grants	*Million HTG*								...		...		...		...	302
Value of Emission Benefits																
Local Benefits of Emission Reductions	*Million HTG*	*NO CF*					101	102	...	1.02	...	103	...	103	...	
TOTAL RESOURCE INFLOW (+, VALUE OF ECONOMIC BENEFITS)	*Million HTG*						174	342	....	371	....	396	....	418	....	302
INCREMENTAL ECONOMIC COSTS																
Investment Costs																
Sub-Component A – Transmission Line Physical Investment Costs																
Supplies of Conductors, Equipments and Materials – Overground Line	*Million HTG*	1.027	85.7	114.3	142.9	228.6			...		...		...		...	
Supplies of Conductors, Equipments and Materials – Underground Line	*Million HTG*	1.027	52.1	69.5	86.8	138.9			...		...		...		...	
Equipment and Supplies for Repairs, Substation and Civil Works	*Million HTG*	0.964	15.3	20.5	25.6	40.9			...		...		...		...	
Insurance, and Handling and Transport Services	*Million HTG*	1.046	4.7	6.2	7.8	12.4			...		...		...		...	
Sub-Total	*Million HTG*		157.8	210.4	263.0	420.8			...		...		...		...	
Sub-Component B – Resettlement and Compensation Costs																
Land Acquisisation and Housing Costs	*Million HTG*	0.901	3.2	4.3	5.3	8.5			...		...		...		...	
Compensation of Farmers and Land Owners	*Million HTG*	1.000	1.7	2.3	2.9	4.6			...		...		...		...	
Compensation of Businesses	*Million HTG*	1.000	1.8	2.4	3.0	4.8			...		...		...		...	
Administration, Management and Monitoring Costs	*Million HTG*	1.000	2.8	3.7	4.7	7.5			...		...		...		...	
Sub-Total	*Million HTG*		9.6	12.7	15.9	25.5			...		...		...		...	
Sub-Component C – Labour Costs During Construction																
Skilled Labour Costs	*Million HTG*	0.932	18.2	18.6	19.0	19.4			...		...		...		...	
Semi-Skilled Labour Costs	*Million HTG*	0.883	10.6	10.8	11.1	11.3			...		...		...		...	
Total Direct Unskilled Labor Cost	*Million HTG*	0.700	10.1	10.3	10.5	10.7			...		...		...		...	
Sub-Total	*Million HTG*		39.0	39.7	40.5	41.3			...		...		...		...	
ECONOMIC COSTS OF INVESTMENTS	*Million HTG*		206.3	262.9	319.5	487.6			...		...		...		...	
Additional Operating Costs																
Total Incremental Operation and Maintenance Expense paid by Electric Utility	*Million HTG*	0.964	0.0	0.0	0.0	0.0	0.2	0.2	...	0.2	...	0.2	...	0.2	...	3.2
TOTAL RESOURCE OUTFLOW (-)	*Million HTG*		206	263	319	488	0	0	...	0	...	0	...	0	...	3
NET RESOURCE FLOW BEFORE TAXES	*Million HTG*		(206)	(263)	(319)	(488)	174	342	...	371	...	396	...	418	...	299
Taxes on Peak Energy Sales																
Incremental Utility Taxes on Peak Energy Sales	*Million HTG*	0	0	0	0	0	0	0	...	0	...	0	...	0	...	0
Incremental Taxes Forgone from Reduced Peak-Load Self-Electricity Generation	*Million HTG*	*NO CF*	0	0	0	0	34	45	...	51	...	57	...	62	...	0
NET RESOURCE FLOW AFTER TAX	*Million HTG*		-206	-263	-319	-488	141	297	...	319	...	339	...	356	...	299

Economic Opportunity Cost of Kapital (EOCK)	8.0%	%
Economic NPV	1,788	*Million HTG*
EIRR	18%	%
Real Exchange Rate (HTG/US$ – year 0)	55	#
Economic NPV	32.5	*Million US$*

5.2.4 Economic Feasibility

In the economic analysis, all prices are measured in economic terms, and the resulting economic resource statement of the project is presented in Table 14. Using the economic opportunity cost of capital for Haiti of 8% real, the estimated economic NPV of the proposed plant is HTG 1,788 million (equivalent to US$ 32.5 Million). This is over and above the economic cost of the investment of US$ 23.2 million. Therefore, the country as a whole is better off with the proposed project, and overall wealth of Haitians will be expanded due to the contribution of this project.

The value of economic benefits realized by the country is significantly larger than the amount of resources used for the construction and rehabilitation of the transmission line, which is also confirmed by the estimated internal rate of return of economic net resource flow (EIRR) of 18%.

5.2.5 Economic Sensitivity Analysis of Project

A number of sensitivity tests are carried out to identify critical parameters affecting the project's economic performance. This section lists the most important parameters identified during the analysis.

L-R Average Real International Price of Crude Oil (US$/bbl)

The economy will save fuel during both off-peak and peak-load hours. The price of fuel is closely linked to the international price of crude oil. Therefore, an expectation of higher long-run real average fuel price will increase the benefits from this project. The direction of both financial benefits and economic benefits are the same if the real average crude oil price is higher than its assumed rate.

The economic benefits from incremental off-peak energy savings are less than the financial benefits, given that CF for oil is less than 1. However, peak-load energy savings of the utility is valued at the marginal cost of own generation.[90] The marginal cost of own-generation is always higher than the utility tariff rates, therefore, the total discounted net economic impacts from the higher real average price of oil are larger than its net impacts on the electric utility.

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[90] Electricity retail tariff (i.e. market price of electricity) reflects value to the electric utility. Under the assumption of peak-load energy will be delivered and consumed by consumers, and the electric utility will not be able to save capacity in the system, the economic value of peak load sales must be estimated at reduced self-generation costs, by the amount of net incremental energy transmitted due to the project.

Table 15. Economic Sensitivity Test of L-R Real Average Price of Crude Oil (US$/bbl)

	NPV Economomy (Millions of HTG)
35	1,165
40	1,372
45	1,580
50	**1,788**
55	1,995
60	2,203
65	2,410

During the lifetime of the project, if the future real average price of oil is 5 US$/bbl above its assumed real average level at 50 US$/bbl, the economic NPV of the project rises by HTG 217 million (equivalent to US$ 3.9 Million). However, it will decrease by HTG 217 million (equivalent to US$ 3.9 million) for 5 US$/bbl decrease in price.

L-R Equilibrium Real Exchange Rate (%)

The economic benefits and economic costs are all subject to real exchange rate fluctuations. Because the discounted economic benefits are larger than the discounted economic costs, the higher real exchange rate (# HTG/ US$) will improve the economic viability of the project. The higher real exchange rate will lead a greater nominal exchange rate between HTG/US$, and this will increase the HTG values of production cost savings of the utility and private consumers.

Table 16. Economic Sensitivity Test of L-R Average Real Exchange Error (%)

	NPV Economomy (Millions of HTG)
-4.0%	1,710
-2.0%	1,749
0.0%	**1,788**
2.0%	1,826
4.0%	1,865

Investment Costs Over-run (%)

Table 17 shows the resulting economic outcomes under a range of possible cost overruns. For instance, a 10% escalation of investment cost leads to an economic loss of HTG 96 million or about 7.5 % of the initial investment value in economic terms. The net discounted economic returns become zero if the costs increase by approximately 190% (i.e. break-even cost-overrun factor)[91].

[91] Holding everything else constant (ceteris paribus), goal seek function of excel helps us to find break-even prices (or costs) for project outcome.

Table 17. Economic Sensitivity Test of Investment Costs Overrun (%)

	NPV Economomy (Millions of HTG)
-15%	1,931
-10%	1,883
-5%	1,835
0%	**1,788**
5%	1,740
10%	1,692
15%	1,644

The economic benefits will improve if costs are lower than predicted today. The implication of such real-cost reduction is that surplus grants will finance other "good" projects that require funding, or existing projects that require extra funding. Therefore, the cost over-run is a critical parameter from the economy point of view.

Discount Rate - EOCK (%)

The EOCK used in the calculation is 8%. Table 18 shows that if lower economic discount rate used for economic analysis, the economic NPV of the project will improve, or vice-versa.

Table 18. Economic Sensitivity Test of Real Discount Rate (%)

	NPV Economomy (Millions of HTG)
6%	2,803
7%	2,237
8%	**1,788**
9%	1,426
10%	1,132

The results are sensitive to the choice of discount rate, however, all the NPVs using a reasonable range of discount rates are strongly positive.

5.3 Stakeholder and Distributive Analysis

The report also examines the impact of the program on various stakeholders. While some of the involved parties may gain due to the program activities, the others may have to incur a loss.

The net impact on all stakeholders created by the program is a sum of the negative and positive externalities imposed on the stakeholders. The magnitude of the impact is measured by the NPV expected to be realized by each group. It is important to assess the magnitude of any gain/burden imposed on each of the stakeholders.

5.3.1 Identification of Externalities

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

$$P_e = P_f + \sum_{i=1} E_i$$

where:

P_e is the economic value of an input or output

P_f is the financial value of the same variable

$\sum_i E_i$ is the sum of all the externalities, "i" (i.e. consumer surplus, government tax impacts, labor benefits, etc.) that make the economic value different from the financial value of the item.[92]

In other words, the economic value of an item can be expressed as the sum of its financial price plus the value of externalities, such as consumer surplus, gov't fiscal impacts, labor benefits. On the basis of identity above, the following relationship also holds, if a common discount rate is applied:[93]

$$NPV_e^{EOCK} = NPV_f^{EOCK} + PV^{EOCK} \sum_i E_i$$

Therefore,

$$PV^{EOCK} \sum_i E_i = NPV_e^{EOCK} - NPV_f^{EOCK}$$

Where:

NPV_e^{EOCK} is the NPV of the net economic benefits
NPV_f^{EOCK} is the NPV of the net financial cashflow
$PV^{EOCK} \sum_i E_i$ is the sum of the PVs of all the externalities generated by the project.

The project generates two types of net benefits: net financial benefits, which accrue directly to those that have a financial interest in the project; and externalities, which are allocated to different segments of society. The stakeholder analysis requires the following steps:

92 See Jenkins (1999), and Jenkins et al., Chapter 13 of Cost-Benefit Analysis for Investment Decisions.
93 In this case, the economic opportunity cost of capital (EOCK).

- Identifying the stakeholder impacts of the project, item-by-item, by subtracting the financial cash flow statement from the economic statement of benefits and costs.

- Calculating the present value of each line item's flow of externalities, using the economic cost of capital as the discount rate.

- Allocating the present value of the externalities to the relevant groups in the economy (i.e. distributive analysis).

Table 19 identifies the stakeholder impacts of the project, item-by-item, by subtracting the financial cash flow statement from the economic statement of benefits and costs. The CSCF estimates for each item is presented in Table 13, page 41. Hence, there exist external benefits and/or costs for each project item as long as the item's CSCF is different from 1. After the externalities are distributed, reconciliation between the financial cash flow and the economic resource flow with the distributive impacts is conducted. The primary aim of this task is to ensure that the analysis has been carried out in a consistent manner.

Table 20 presents the reconciliation between the financial, economic and externalities of the proposed project, all discounted by economic cost of capital of 8% real. If the economic NPV is equal to the financial NPV plus the present value of distributional impacts, using a common discount rate, it indicates that the analysis was carried out in a consistent manner. The economic NPV is the same as shown in Table 14. However, the financial NPV does not have to be equal the one displayed in Table 8 because the financial net cash flow might be discounted at the rate. For this analysis, the same discount rate is used for both the financial and economic analysis of the project.

Table 19. Annual Flow for Statement of Externalities (Real, Millions of HTG)

STATEMENT OF EXTERNALITIES (REAL)		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
EXTERNALITIES FROM INCREMENTAL BENEFITS															
Production Cost Savings During Off-Peak Load Hours															
Value of Fuel Savings During Off-Peak Load Hours	*Million HTG*					(0.25)	(0.52)	...	(0.54)	...	(0.56)	...	(0.57)	...	
Value of O&M Cost Savings Durig Off-Peak Load Hours	*Million HTG*					(0.02)	(0.04)	...	(0.05)	...	(0.05)	...	(0.06)	...	
Incremental Energy Delivered for Peak-Load Consumption															
Value of Peak Load Sales / Reduction in Peak Load Self Generation	*Million HTG*					38.72	51.96	...	60.01	...	67.23	...	73.63	...	
Value of Incremental Transmission Capacity from Additional 10 MW Hydro Capacity															
Value of Avoided Transmission Costs for Future Generation Expansion	*Million HTG*						1.99	...	1.98	...	1.98	...	1.97	...	
EXTERNALITIES FROM ENERGY AND TRANSMISSION BENEFITS	*Million HTG*					38.45	53.39	...	61.40	...	68.60	...	74.98	...	
Residual Values															
Liquidation Value of Transmission Line Assets	*Million HTG*							...		...		...		...	7.85
Grants															
Total Investments Grants, by Haiti-Reconstruction Fund (HRF)	*Million HTG*	(146.51)	(180.93)	(215.37)	(316.82)			...		...		...		...	
Total Investments Grants, by Inter-American Development Bank (IDB)	*Million HTG*	(64.01)	(85.35)	(106.69)	(170.70)			...		...		...		...	
Residual Value of Transmission Assets + Grants	*Million HTG*	(210.53)	(266.28)	(322.06)	(487.52)			...		...		...		...	7.85
Value of Emission Benefits															
Local Benefits of Emission Reductions	*Million HTG*					0.01	0.02	...	0.02	...	0.03	...	0.03	...	
TOTAL EXTERNALITIES FROM RESOURCE INFLOW	*Million HTG*	-211	-266	-322	-488	38	53	...	61	...	69	...	75	...	8
EXTERNALITIES FROM INCREMENTAL COSTS															
Investment Costs															
Sub-Component A - Transmission Line Physical Investment Costs															
Supplies of Conductors, Equipments and Materials - Overground Line	*Million HTG*	2.23	2.97	3.72	5.94			...		...		...		...	
Supplies of Conductors, Equipments and Materials - Underground Line	*Million HTG*	1.35	1.81	2.26	3.61			...		...		...		...	
Equipment and Supplies for Repairs, Substation and Civil Works	*Million HTG*	(0.58)	(0.77)	(0.97)	(1.54)			...		...		...		...	
Insurance, and Handling and Transport Services	*Million HTG*	0.20	0.27	0.34	0.55			...		...		...		...	
Sub-Total	*Million HTG*	3.21	4.28	5.35	8.56			...		...		...		...	
Sub-Component B - Resettlement and Compensation Costs															
Land Acquisisation and Housing Costs	*Million HTG*	(0.35)	(0.47)	(0.59)	(0.94)			...		...		...		...	
Compensation of Farmers and Land Owners	*Million HTG*							...		...		...		...	
Compensation of Businesses	*Million HTG*							...		...		...		...	
Administration, Management and Monitoring Costs	*Million HTG*							...		...		...		...	
Sub-Total	*Million HTG*	(0.35)	(0.47)	(0.59)	(0.94)			...		...		...		...	
Sub-Component C - Labour Costs During Construction															
Skilled Labour Costs	*Million HTG*	(1.34)	(1.37)	(1.39)	(1.42)			...		...		...		...	
Semi-Skilled Labour Costs	*Million HTG*	(1.41)	(1.44)	(1.47)	(1.50)			...		...		...		...	
Total Direct Unskilled Labor Cost	*Million HTG*	(4.32)	(4.41)	(4.49)	(4.58)			...		...		...		...	
Sub-Total	*Million HTG*	(7.07)	(7.21)	(7.35)	(7.50)			...		...		...		...	
TOTAL EXTERNALITIES FROM INVESTMENT SPENDINGS	*Million HTG*	(4.21)	(3.40)	(2.59)	0.12			...		...		...		...	
Additional Operating Costs															
Total Incremental Operation and Maintenance Expense paid by Electric Utility	*Million HTG*					(0.01)	(0.01)	...	(0.01)	...	(0.01)	...	(0.01)	...	(0.12)
TOTAL RESOURCE OUTFLOW (-)	*Million HTG*	(4.21)	(3.40)	(2.59)	0.12	(0.01)	(0.01)	...	(0.01)	...	(0.01)	...	(0.01)	...	(0.12)
NET RESOURCE FLOW BEFORE TAXES	*Million HTG*	(206.32)	(262.88)	(319.47)	(487.64)	38.48	53.42	...	61.43	...	68.63	...	75.01	...	7.97
Taxes on Peak Energy Sales															
Incremental Utility Taxes on Peak Energy Sales	*Million HTG*					(3.07)	(4.11)	...	(4.57)	...	(4.95)	...	(5.25)	...	
Incremental Taxes Forgone from Reduced Peak-Load Self-Electricity Generation	*Million HTG*					33.59	45.00	...	51.28	...	56.83	...	61.71	...	
NET EXTERNALITY FLOW	*Million HTG*	(206)	(263)	(319)	(488)	8	13	...	15	...	17	...	19	...	8

Economic Opportunity Cost of Kapital (EOCK)	8%	%
PV of Externalities	(975.85)	*Million HTG*
Real Exchange Rate (HTG/US$ - year 0)	55	#
PV of Externalities	-17.7	*Million US$*

Table 20. Reconciliation Between Financial, Economic and Externalities (Real, Millions of HTG)

RECONCILIATION BETWEEN FINANCIAL, ECONOMIC AND EXTERNALITIES (REAL)						
INCEREMENTAL BENEFITS		PV Fin	PV Ext	PV Fin + PV Ext	PV Econ	Check
Production Cost Savings During Off-Peak Load Hours						
Value of Fuel Savings During Off-Peak Load Hours	*Million HTG*	840	-5	836	836	OK
Value of O&M Cost Savings Durig Off-Peak Load Hours	*Million HTG*	12.0	-0.4	11.6	11.6	OK
Incremental Energy Delivered for Peak-Load Consumption						
Value of Peak Load Sales / Reduction in Peak Load Self Generation	*Million HTG*	1,299	552	1,852	1,852	OK
Value of Incremental Transmission Capacity from Additional 10 MW Hydro Capacity						
Value of Avoided Transmission Costs for Future Generation Expansion	*Million HTG*	648	17	665	665	OK
TOTAL INCREMENTAL ENERGY AND TRANSMISSION BENEFITS	*Million HTG*	2,800	564	3,364	3,364	OK
Residual Values						
Liquidation Value of Transmission Line Assets	*Million HTG*	10	0	10	10	OK
Grants						
Total Investments Grants, by Haiti-Reconstruction Fund (HRF)	*Million HTG*	750	-750	0	0	OK
Total Investments Grants, by Inter-American Development Bank (IDB)	*Million HTG*	370	-370	0	0	OK
TOTAL RESIDUAL ASSET VALUES AND GRANTS	*Million HTG*	1,130	-1,120	10	10	OK
Value of Emission Benefits						
Local Benefits of Emission Reductions			0.21	0.21	0.21	OK
TOTAL BENEFITS (+)	*Million HTG*	3,930	-555	3,374	3,374	OK
INCREMENTAL COSTS		PV Fin	PV Ext	PV Fin + PV Ext	PV Econ	Check
Investment Costs						
Sub-Component A : Transmission Line Physical Investment Costs						
Supplies of Conductors, Equipments and Materials : Overground Line	*Million HTG*	483	13	495	495	OK
Supplies of Conductors, Equipments and Materials : Underground Line	*Million HTG*	293	8	301	301	OK
Equipment and Supplies for Repairs, Substation and Civil Works	*Million HTG*	92	-3	89	89	OK
Insurance, and Handling and Transport Services	*Million HTG*	26	1	27	27	OK
Sub-Total	*Million HTG*	894	19	912	912	OK
Sub-Component B : Resettlement and Compensation Costs						
Land Acquisisation and Housing Costs	*Million HTG*	21	-2	18	18	OK
Compensation of Farmers and Land Owners	*Million HTG*	10	0	10	10	OK
Compensation of Businesses	*Million HTG*	10	0	10	10	OK
Administration, Management and Monitoring Costs	*Million HTG*	16	0	16	16	OK
Sub-Total	*Million HTG*	57	-2	55	55	OK
Sub-Component C : Labour Costs During Construction						
Skilled Labour Costs	*Million HTG*	72	-5	67	67	OK
Semi-Skilled Labour Costs	*Million HTG*	44	-5	39	39	OK
Total Direct Unskilled Labor Cost	*Million HTG*	53	-16	37	37	OK
Sub-Total	*Million HTG*	169	-26	143	143	OK
TOTAL INCREMENTAL INVESTMENT COSTS	*Million HTG*	1,120	-9	1,111	1,111	OK
Additional Operating Costs						
Total Incremental Operation and Maintenance Expense paid by Electric Utility	*Million HTG*	4	0	4	4	OK
TOTAL COSTS (OUTFLOWS)	*Million HTG*	1,124	-10	1,115	1,115	OK
NET COSTS (BEFORE TAXES)	*Million HTG*	2,805	-546	2,260	2,260	OK
Taxes on Peak Energy Sales						
Incremental Utility Taxes on Peak Energy Sales	*Million HTG*	42	-42	0	0	OK
Incremental Taxes Forgone from Reduced Peak-Load Self- Electricity Generation	*Million HTG*		472	472	472	OK
NPV @ EOCK	*Million HTG*	2,763	-976	1,788	1,788	OK

5.3.2 Distributive Analysis (Allocation of Externalities)

The integrated appraisal framework allows the analyst to reconcile the total externalities with the gains and losses accruing to each of different stakeholders. In this section of the report, the net contribution of the project to the impacted groups is presented.[94]

Table 21 presents the allocation of economic externalities generated by this program and includes consumers, local labor, the government's treasury, and the other projects. If the project gets approval for the implementation, the PV of externalities are estimated at HTG 976 Million, or equivalent to US$ 17.7 Million. The externalities are distributed over the following impacted groups in the economy:

Electricity Consumers: The difference between the marginal cost of self-generation per kWh and electricity tariff reflects the consumer surplus. Because self-electricity generation is more costly than purchasing energy from the grid, consumers are benefiting from reduced higher cost of own-generation. The estimated discounted consumer surplus is HTG 553 million, or equivalent to US$ 10 Million.

The Government of Haiti: The government will be able to collect incremental tax revenues from both incremental peak-load energy sales and through income taxes paid by labor employment during the construction of the project. However, the Gov't will be losing a large volume of revenue from the reduction in taxes that would have been levied on the fuel that is now saved by electricity generation by the electric utility. In addition, there will be lower tax revenues because of the reduced purchase of fuel by the private generators that would have been subject to taxation. The estimated discounted gov't fiscal impacts are HTG 431 million, or equivalent to US$ 7.8 Million.

The electric utility has been debt-financed by the local government. Under the consolidated analysis, where the financial impacts from the utility and government treasury are combined, the government of Haiti will be saving more funds than the utility.

Local Labor: The economic cost of labor (EOCL) employed by the project is estimated using the supply price approach. The approach starts with the wages paid by the project and deducts all applicable withholding and income taxes to arrive at the net income received by the labor.[95] Because project wages are higher than the alternative wage they would earn, they will be better off due to the project. The estimated discounted labor benefits are HTG 23 million, or equivalent to US$ 0.41 Million.

[94] See Annex J, page 104-105.
[95] See Chapter 12, of Jenkins et al. (2011).

Table 21. Distributive Analysis of Externalities (Real, Millions of HTG)

DISTRIBUTIVE ANALYSIS (REAL)

	Unit	PV Ext	i) Electricity Consumers	ii) Labour	iii) Gov't Fiscal Impacts (i.e. tax)	iv) Other Projects
EXTERNALITIES FROM INCREMENTAL BENEFITS						
Production Cost Savings During Off-Peak Load Hours						
Value of Fuel Savings During Off-Peak Load Hours	Million HTG	-5			-5	
Value of O&M Cost Savings Durig Off-Peak Load Hours	Million HTG	-0.4			-0.4	
Incremental Energy Delivered for Peak-Load Consumption						
Value of Peak Load Sales / Reduction in Peak Load Self Generation	Million HTG	552	552			
Value of Incremental Transmission Capacity from Additional 10 MW Hydro Capacity						
Value of Avoided Transmission Costs for Future Generation Expansion	Million HTG	17			17	
TOTAL INCREMENTAL ENERGY AND TRANSMISSION BENEFITS	Million HTG	564	552	0	12	0
Residual Values						
Liquidation Value of Transmission Line Assets	Million HTG	0.27			0.3	
Grants						
Total Investments Grants, by Haiti-Reconstruction Fund (HRF)	Million HTG	-750				-750
Total Investments Grants, by Inter-American Development Bank (IDB)	Million HTG	-370				-370
TOTAL RESIDUAL ASSET VALUES AND GRANTS	Million HTG	-1,120	0	0	0	-1,120
Value of Emission Benefits						
Local Benefits of Emission Reductions	Million HTG	0.21	0.21			
TOTAL EXTERNALITIES FROM BENEFITS	Million HTG	-555	553	0	12	-1,120
EXTERNALITIES FROM INCREMENTAL COSTS		**PV Ext**	**i) Electricity Consumers**	**ii) Labour**	**iii) Gov't Fiscal Impacts (i.e. tax)**	**iv) Other Projects**
Investment Costs						
Sub-Component A : Transmission Line Physical Investment Costs						
Supplies of Conductors, Equipments and Materials : Overground Line	Million HTG	13			13	
Supplies of Conductors, Equipments and Materials : Underground Line	Million HTG	8			8	
Equipment and Supplies for Repairs, Substation and Civil Works	Million HTG	-3			-3	
Insurance, and Handling and Transport Services	Million HTG	1			1	
Sub-Total	Million HTG	19	0	0	19	0
Sub-Component B : Resettlement and Compensation Costs						
Land Acquisation and Housing Costs	Million HTG	-2		-1	-1	
Compensation of Farmers and Land Owners	Million HTG	0			0	
Compensation of Businesses	Million HTG	0			0	
Administration, Management and Monitoring Costs	Million HTG	0	0			
Sub-Total	Million HTG	-2	0	-1	-1	0
Sub-Component C : Labour Costs During Construction						
Skilled Labour Costs	Million HTG	-5		-3	-2	
Semi-Skilled Labour Costs	Million HTG	-5		-3	-2	
Total Direct Unskilled Labor Cost	Million HTG	-16		-16	0	
Sub-Total	Million HTG	-26	0	-22	-4	0
TOTAL EXTERNALITIES FROM INVESTMENT COSTS	Million HTG	-9	0	-23	13	0
Additional Operating Costs						
Total Incremental Operation and Maintenance Expense paid by Electric Utility	Million HTG	0			0	
TOTAL EXTERNALITIES FROM COSTS	Million HTG	-10	0	-23	13	0
NET EXTERNALTIES BEFORE TAXES ON ENERGY SALES	Million HTG	-546	553	23	-1	-1,120
Taxes on Peak Energy Sales						
Incremental Utility Taxes on Peak Energy Sales	Million HTG	-42			-42	
Incremental Taxes Forgone from Reduced Peak-Load Self-Electricity Generation	Million HTG	472			472	
PV of NET EXTERNAL IMPACTS	Million HTG	-976	553	23	-431	-1,120
Real Exchange Rate (HTG/US$: year 0) 55	#					
PV of NET EXTERNAL IMPACTS	Million US$	(17.74)	10.05	0.41	(7.83)	(20.37)

Other Local Projects: Haiti Reconstruction Fund (HRF) and Inter-American Development Bank (IDB) are both financing the project through grants,[96] therefore, there are fewer funds available for other local projects within Haiti. The estimated discounted costs to other projects are HTG 1,120 million, or equivalent to US$ - 20.4 Million.

5.3.3 Externalities & Distributive Sensitivity Analysis of Project

This section summarizes the impacts of the risky/uncertain variables on impacted groups of the economy.

<u>*L-R Average Real International Price of Crude Oil (US$/bbl)*</u>

During the life-time of the project, if future real average price of crude oil is increased by 5.00 US$/bbl, the PV of consumers' benefits will increase by the amount of HTG 85 million (equivalent to US$ 1.5 million), but it will decrease by the same amount of HTG 85 million (equivalent to US$ 1.5 million) if it is 5 US$/bbl lower. Therefore, for a higher average real price of crude oil, the improvement the consumers' welfare from the reduced peak load own-generation costs outweighs the impact of the increased peak load energy bill they pay to the electric utility[97]. It is a highly critical parameter from the point of electricity consumers.

Table 22. Externalities Sensitivity Test of International Price of Crude Oil (US $/bll)

	PV of Local Externalities (Millions of HTG)	i) Electricity Consumers (Millions of HTG)	ii) Labor (Millions of HTG)	iii) Gov't Tax Impacts (Millions of HTG)	iv) Other Projects (Millions of HTG)
35	-1,101	297	23	-300	-1,120
40	-1,059	382	23	-344	-1,120
45	-1,017	467	23	-387	-1,120
50	-976	553	23	-431	-1,120
55	-934	638	23	-474	-1,120
60	-893	723	23	-518	-1,120
65	-851	808	23	-562	-1,120

On the other hand, if the future real average price of crude oil is 5.0 US$/bbl above its assumed level at 50 US$/bbl, the Gov't treasury will lose more taxes. Gov't tax collections are largely from the utility peak load sales less the taxes lost from reduced peak load self-generation. For instance, if the future real average price of crude oil is increased by 5.0 US$/bbl the government's tax <u>loss</u> will increase by the amount of HTG 44 million (equivalent to US$ 0.8 million). The reason is that the increase in the real average crude oil price will increase the retail price of the utility by a smaller amount on the margin than it will increase the marginal private cost of self-generation. Therefore, for every kWh of energy, the government should expect to lose more of taxes than it will

[96] See Table 2.

[97] Note that the estimated consumer welfare impacts here are from the transmission project alone. Therefore, the overall consumer welfare might potentially decrease as the higher fuel price will increase their <u>total</u> energy bill from total energy consumption. The transmission project, however, will still reduce their total bills. In other words, total consumer bills will be higher without the transmission project due to the high cost of self-generation.

probably collect as a result of an increase in the real average crude oil price. It is a highly critical parameter from the gov't point of view.

L-R Equilibrium Real Exchange Rate (%)

As shown in Table 23, the real exchange rate is the key variable for all stakeholders, with the exception of labor.[98] Consumer benefits from this project will improve with a higher level of the long-run average real crude oil price caused by a higher real exchange rate. The net savings of consumers will increase because the reduced fuel purchases from self-generation are greater than the additional cost of electricity purchases from the utility. This implies higher government tax losses

Table 23. Externalities Sensitivity Test of L-R Real Exchange Rate (%)

	PV of Local Externalities (Millions of HTG)	i) Electricity Consumers (Millions of HTG)	ii) Labor (Millions of HTG)	iii) Gov't Tax Impacts (Millions of HTG)	iv) Other Projects (Millions of HTG)
-4.0%	-943	531	23	-413	-1,082
-2.0%	-959	542	23	-422	-1,101
0.0%	-976	553	23	-431	-1,120
2.0%	-993	564	23	-440	-1,139
4.0%	-1,009	575	23	-448	-1,158

Investment Costs Over-run (%)

The investment cost over-run will capture the impacts on other projects of the additional funds required to finance the transmission project. As shown in Table 25, a 10% escalation of investment cost by this aid-financed project will displace HTG 95 Million (or equivalent to US$1.7 Million) from other projects that would have been otherwise financed.

Table 24. Externalities Sensitivity Test of Investment Cost Over-Run (%)

	PV of Local Externalities (Millions of HTG)	i) Electricity Consumers (Millions of HTG)	ii) Labor (Millions of HTG)	iii) Gov't Tax Impacts (Millions of HTG)	iv) Other Projects (Millions of HTG)
-15%	-831	553	23	-428	-978
-10%	-879	553	23	-429	-1,025
-5%	-927	553	23	-430	-1,073
0%	-976	553	23	-431	-1,120
5%	-1,024	553	23	-432	-1,168
10%	-1,073	553	23	-433	-1,215
15%	-1,121	553	23	-433	-1,263

If funds are not scarce, then investment cost over-run will only result in an increase in transfers from the international aid.

5.4 Risk Analysis

The first step in undertaking a CBA is to develop a spreadsheet model for the *ex-ante* evaluation that can be used to undertake a risk analysis. The data and

[98] Project wages are determined in local currency, HTG.

assumptions used to begin the *ex-ante* calculation of costs and benefits are usually single value input estimates (i.e. mode or average, values). However, the estimated *ex-ante* costs and benefits presented in cash/resource-flow statements are subject to a degree of uncertainty associated with data measurement, model and forecast errors. Hence, a probabilistic risk analysis is performed to analyze the variability in the financial and economic returns of the project.

In the integrated analysis, it is possible to run a model of a project through a Monte-Carlo simulation where distributions for variable values are substituted for single and deterministic estimates. The result will yield mean estimates of possible project outcomes. Monte Carlo simulations, a form of risk analysis, provide one of the most practical methods to approximate the dynamics of risks and uncertainties of the real world.[99]

5.4.1 Selection of Risk Variables and Probability Distributions

The sensitivity analysis carried out as a part of a financial and economic assessment has already helped in finding the critical parameters affecting the performance of the proposed project. Once the risky/uncertain variables are identified, the second step is to select an appropriate probability distribution and the likely range of values for each risk variable. The probability distributions are based either on historical observations of this variable or expert's opinion[100]. The probability distributions of each risk variable and the possible range of its values are presented below.

Using a Monte Carlo simulation generates a probability distribution of the outcome of the project including the NPVs and PV of impact on each stakeholder based on the underlying uncertainty surrounding each of the key risk variables specified in Table 25. During the risk simulation for this project, the following project indicators were monitored:

(i) the project's Financial and Economic NPV

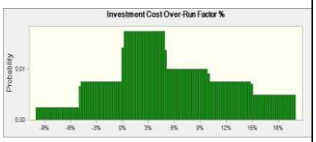
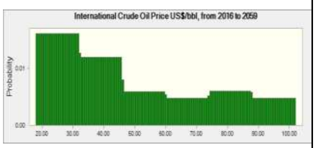
(ii) PV of net externalities and PVs of impact on each stakeholder (i.e. impacts on electricity consumers, gov't tax impacts, labor, and other projects)

[99] For more information, see Savvides (1993), and Salci and Jenkins (2016).
[100] For more information, see Sanderson (2012).

Table 25. List of High-Risk Factors on Project Outcomes[101], [102]

Risk variables	Impact and risk significance
Investment cost overruns (%)	High impact on the increase of investment costs, therefore an increase in required grants and/or displacement of funds from other project(s). The probability distribution is derived based on experts' opinion and relevant transmission projects from the past.
L-R Average World Price of Crude Oil (US$/bbl)	High impact on the financial and economic results. It is beyond Haiti's control. The probability distribution is derived from historical data. (See Appendix E)
Real Exchange Rate Appreciation/ Depreciation (HTG/US$)	Medium impact on the financial and economic results. It is beyond Haiti's control and depends on foreign aid flow and political risks. The probability distribution cannot be derived.
Discount Rate (%)	Significant impact on the EDH revenues and the economic viability of the project. It is unknown, and cannot be known as the opportunity cost of funds is tied to uncertainty on the future flow of funds. The probability distribution cannot be derived. .

Table 26. Probability Distributions for Risk Variables

Variable	Distribution Type		Range and Parameters	Mean Value[103]
Cost Over-Runs Factor	Step Distribution		Min to Max: Likelihood -10% to -5%: 5% -5% to 0%: 10% 0% to 5%: 35% 5% to 10%: 25% 10% to 15%: 15% 15% to 20%: 10%	Deterministic Assumption: 0% Expected: 4%
L-R Average Real Crude Oil Price	Step Distribution		Min to Max: Likelihood 18 to 32: 32% 32 to 46: 24% 46 to 60: 12% 60 to 74: 10% 74 to 88: 12% 88 to 102: 10%	Deterministic Assumption: 50 US$/bbl Expected: 49.36 US$/bbl

[101] For the full list of items, see sensitivity analysis sheet of the spreadsheet model.

[102] Note that all risky/uncertain parameters/assumptions should not be used in risk simulations. To illustrate, series of environmental-impact models shows that social cost of carbon is an uncertain variable and it is ranging between -20 US$/ton to 110 US$/ton. The share of carbon savings benefits is less than 0.5% of all total economic benefits from the perspective of Haiti, therefore it is not key variable for this project and evaluations from the perspective of Haiti.

[103] Note that the probability distributions from simulations presented in Figure 10 are almost symmetric/normal distribution (skewness being close to the value of 0), with some degree of deviations from its expected mean. The results, however, are not contradicting the sensitivity tests. The reason is that the long-run mean expected crude oil price is almost the same as its long-run average deterministic price; 50.00 US$/bbl. On the other hand, the expected cost-over-run is slightly higher at 4% compared to its initial deterministic assumption at 0%. The probabilities distributions of the forecast values inform us on the extreme values of the outcomes and their probability of occurrence.

5.4.2 Risk Simulation Results and Interpretation of Results

A Monte-Carlo risk simulation was carried out over 10,000 trials with the help of Crystal Ball™ software. Simulation results are presented by the frequency and cumulative frequency distribution. These are a graphical presentation of the range of possible values that the project outcomes (e.g. financial NPV, economic NPV) can take and the likelihood of occurrence of these values. Summary statistics are also presented from the simulations on the net financial, economic and external benefits.

Financial Outcomes from the Electric Utility (EDH) Point of View

Based on simulations reported in Table 28, the expected value of financial NPV is HTG 2,748 million (≅US$ 50 million) with a standard deviation mean of HTG 161 million (≅US$ 2.9 million). The result also shows that there is no possibility of having a financial loss.

At the extreme lower end of the possible range, the minimum net benefits of the electric utility are HTG 2,211 million (≅US$ 40.2 million), which is about 66% higher than the total undiscounted investment cost of the project. In other words, the electric utility will still earn substantial benefits at the minimum expected long-run average price of crude oil per barrel.

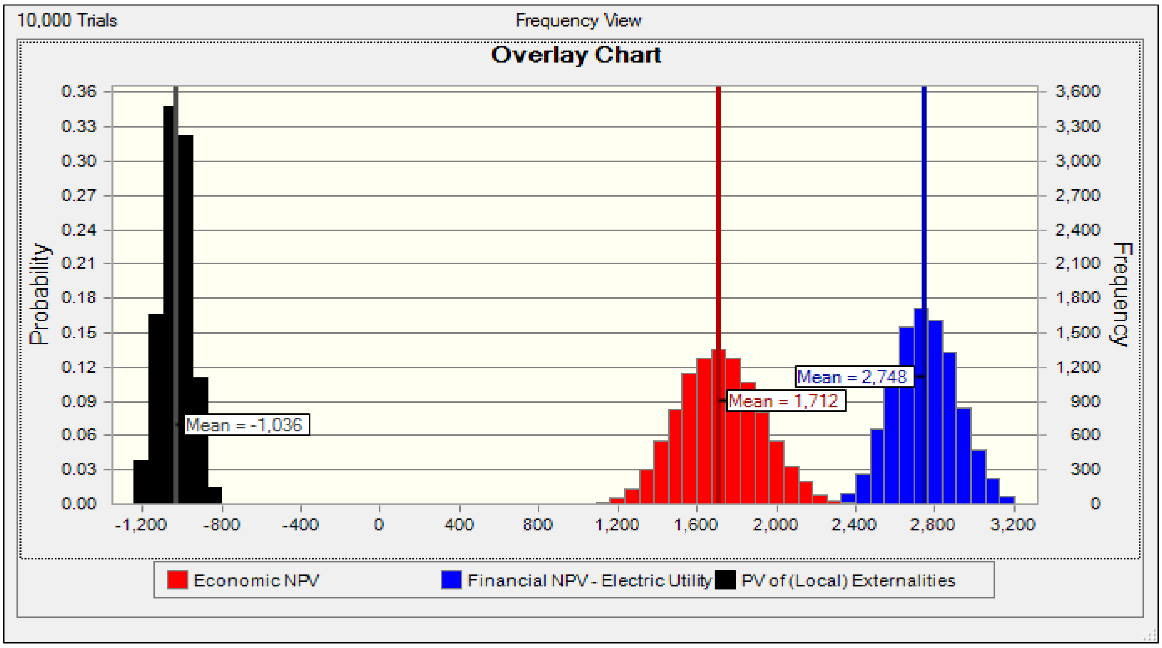
Under the best-case scenario, the maximum net gain of the utility is about HTG 3,348 million (≅US$ 60.9 million), which is about US$ 37.1 million more than the initial total value of the investment costs. Hence, the electric utility will earn abnormal high net benefits at the maximum expected long-run average prices of crude oil per barrel. Therefore, utility benefits will exceed the grant amounts even at the lowest possible range of crude oil price; 18 US$/bbl – 32 US$/bbl.

Economic Outcomes from Country-Economy Point of View

The expected value of the economic NPV is HTG 1,712 million (≅US$ 31.1 million), and converges to its deterministic average estimate. The standard deviation of the mean is about HTG 210 million (≅US$ 3.8 million). The results also show that there is no possibility of having an economic NPV being equal to or less than zero. At the extreme lower end of the possible range, the minimum net gain is HTG 974 million (≅US$ 17.7 million), while in the best-case scenario the maximum net gain is HTG 2,553 million (≅US$ 46.4 million).

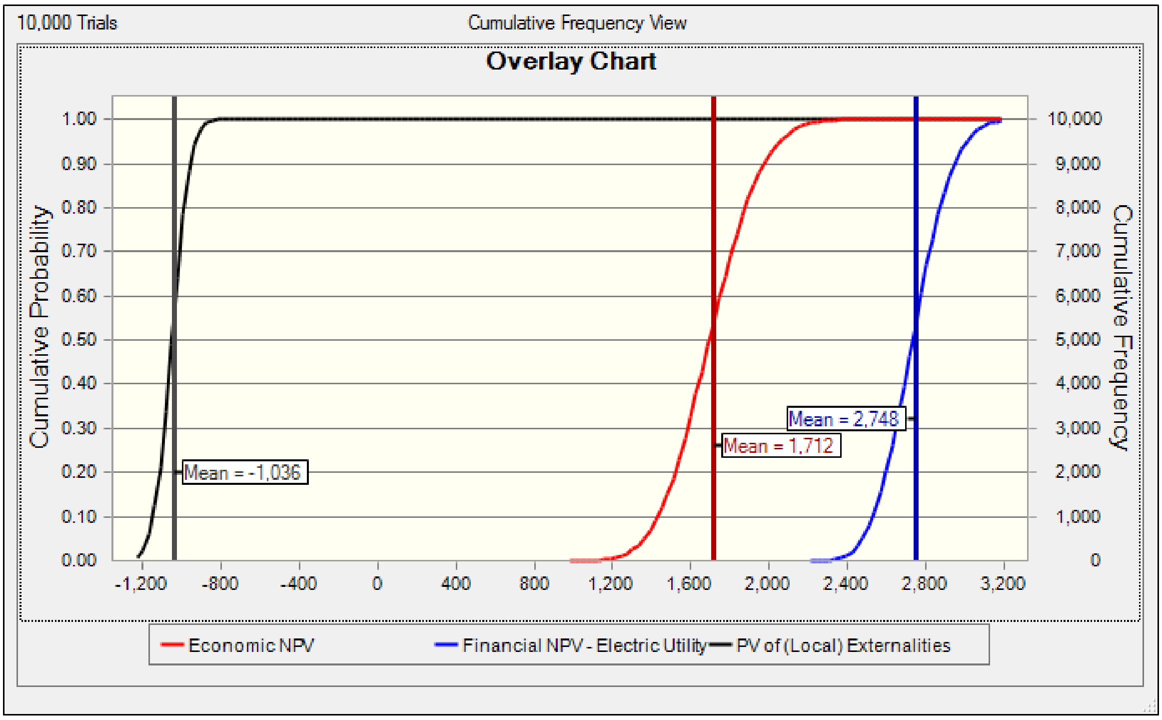
Unlike the net benefits accruing to the electric utility, the net economic benefits are linked to the program's investment costs and the long-run real price of crude oil. Therefore, the impacts of risky/uncertain variables on the economic outcome of the project are larger. However, the net economic benefits will still exceed the grant amounts.

Figure 10. Probability Distribution from Simulations, Impacts on Economy, Utility and Externalities (Real, Millions of HTG)



Source: own simulations.

Figure 11. Cumulative Probability Distribution from Simulations, Impacts on Economy, Utility and Externalities (Real, Millions of HTG)



Sources: own simulations.

Table 27. Summary Descriptive Statistics from Simulations (Real, millions of HTG)

Statistics/Outcome	Economic NPV	Financial NPV	PV of Local Externalities
Trials	10,000	10,000	10,000
Base Case	1,788	2,763	-976
Mean	1,712	2,748	-1,036
Standard Deviation	210	161	74
Skewness	0.12	0.13	-0.04
Minimum	974	2,211	-1,275
Maximum	2,553	3,348	-761
Pr(NPVi) >=0	100%	100%	0%[104]
Pr(NPVi)>=Total Investment Grants (Real, Undiscounted)*	98.5%	100%	not relevant

Source: own simulations.

(**)Total Investment Grants (Real, Undiscounted) amount to HTG 1, 286 Million.

Risk Impacts on Externalities

As reported in Table 28, the expected value of consumers' gain is HTG 544 million (≅US$ 9.9 million) with no possibility of facing a loss from the project. At the extreme lower end of the possible range, the minimum consumer net gain amount to HTG 272 million (≅US$ 4.9 million), while in the best-case scenario the maximum net benefit to consumers is HTG 842 million (≅US$ 15.3 million). The large divergence between the minimum (left tail of the distribution) and the maximum (right tail of the distribution) is expected[105].

The expected value of gov't fiscal impacts is a loss of HTG 427 million (≅US$ 7.8 million) with no possibility of gaining tax revenues directly from the project. At the extreme lower end of the possible range, the minimum loss of gov't is HTG 287 million (≅ US$ 5.2 Million), while in the worst-case scenario the maximum loss is HTG 581 million (≅US$ 10.6 Million). However, when the electric utility gains from the project are included from the gov't perspective, the tax losses are negligible.

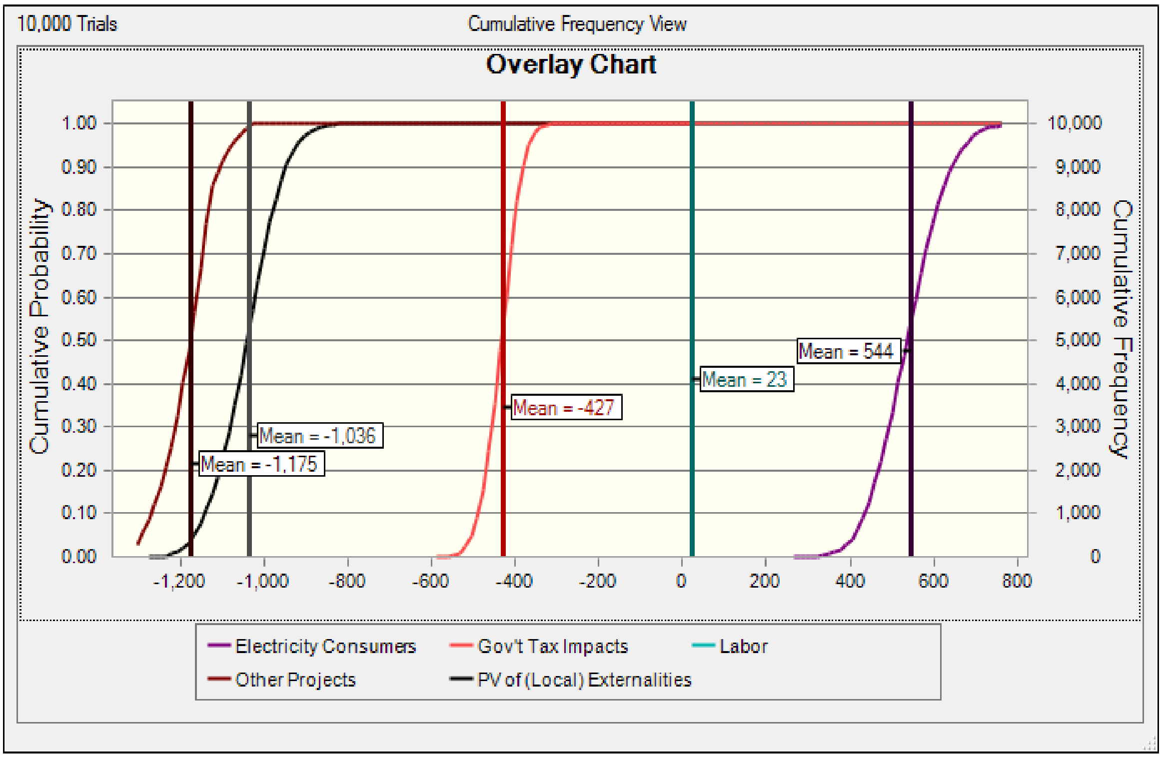
On the expectation that the project's cost will increase, the expected value of losses for the other projects is HTG 1,175 million (≅US$ 21.3 million), with a standard deviation of HTG 62 million. Therefore, the investment costs might be 5% higher when the risks of cost overrun are taken into consideration. At the extreme lower end of the possible range, the maximum amount of funds that will be released from other projects is HTG 1,310 million (≅US$ 23.8

[104] The minimum net expected impacts on electricity consumers and local labor are both positive. The total size of these benefits is smaller than the sum of negative impacts on the government of Haiti and other projects. Therefore, the net negative impacts on gov't of Haiti and other projects dominates the outcome.

[105] See Table 22.

million), which is about 17 % higher than its discounted deterministic value of HTG 1,120 million (≅US$ 20.4 million). Under the best-case scenario, the minimum extraction is HTG1, 025 million (≅US$ 18.6 million), which is approximately 8.4% less than its deterministic estimate at HTG 1,120 million.

Figure 12. Cumulative Probability Distribution from Simulations, Impacts on Externalities (Real, Millions of HTG)



Source: own simulations.

Table 28. Summary Descriptive Statistics from Simulations on PV of Externalities (Millions of HTG)

Statistics/ Outcome	PV of Externalities	a)Consumer Benefits	b) Labor Benefits	c) Gov't Tax Impacts	d) Other Projects
Trials	10,000	10,000	10,000	10,000	10,000
Base Case	-976	553	23	-431	-1.120
Mean	-1,036	544	23	-427	-1,175
Std. Devt.	74	80	0	42	62
Skewness	-0.04	0.13	0.07	-0.13	-0.09
Minimum	-1,275	272	23	-581	-1,310
Maximum	-761	842	23	-287	-1,025
Pr (PVe)<=0	100%	0%	0%	100%	100%

Source: own simulations.

Therefore, the results from risk simulations suggest that from the perspective of consumers there is a very limited risk of suffering a loss. When financial impacts from the utility and government treasury are consolidated, the government of Haiti will have greater savings from the utility gains than it loses from reduced taxes alone. Hence, there is also a very limited risk of losing from the perspective of government.

The possibility of cost over-runs must be considered before the implementation phase of the project, and it is expected to be 5% higher (equivalent to US$ 1 million). The extra funding is worth making in order to secure a project that generates expected returns with a zero risk of loss to the electric utility and country economy of US$ 50 million and US$ 31.1 million, respectively.

6. Conclusions

The integrated investment appraisal methodology has been used in the evaluation of this project. The role of the development banks is to ensure that the grants made available to a country are indeed channeled to an activity that improves the well-being of its citizens. Therefore, an investment appraisal is an invaluable tool for carrying out the basic financial, economic, stakeholder and risk analysis of such potential projects.

The electric utility, currently operates with a poor level of revenue collection from billed electricity sales and suffers from very high losses in transmission and distribution of electricity. This simply means that EDH's financial return on capital is negative. The chronic deficits are reflected in the sector by means of frequent blackouts and delays in investment to strengthen the existing system. It is the direct result of imprudent and reckless energy policies toward system planning, weak governance, and theft.

The objective of the proposed rehabilitated transmission line is to provide additional energy to the electric utility. This is achieved through improved transmission efficiency and increased transmission capacity. It saves production costs during the off-peak periods, earns incremental revenues from the energy sales during the peak load periods, and saves some transmission investment costs for the future expansion of the system.

The financial analysis has confirmed that the project is a viable and sustainable investment for the electric utility in Haiti (EDH). The expected financial NPV of the project is HTG 2,748 million (≅US$ 50 million), using a real discount rate of 8%. The expected economic NPV of the project is HTG 1,712 million (≅US$ 31.1 Million), using an EOCK of 8% real. Its EIRR is 20%. The economic analysis confirms that the project will improve the overall well-being of Haitian residents.

When externalities from the project are allocated to the impacted groups, consumers will gain by HTG 544 Million (US$ 9.9 million), while local labor will gain by HTG 23 Million (US$ .41 million). The potential losers are the gov't of Haiti that will lose tax revenues by HTG 427 Million (US$ 7.8 million), and the other projects will have less access to funds by the amount of 1,175 (US$ 21.3 million). Since the gov't of Haiti has been the sole financier of EDH, the project is also viable from the government's point of view.

The results from risk simulations also suggest that there is a very limited risk to the financial and economic outcomes for the project. A substantial return is expected to accrue to both the electric utility and to the economy with a zero risk of loss. Hence, the Inter-American Development Bank and Haiti Reconstruction Fund are justified in providing grants for financing the implementation of this electricity transmission project.

7. Policy Recommendations

Haiti's electricity supply is currently insufficient to meet the domestic demand and leaves three-quarters of the population without access to electricity services. In addition, the electricity grid has a very high technical and non-technical transmission and distribution losses.

Alongside investments to strengthen the network infrastructure, energy efficiency improvements on both the demand and supply sides and a program to reduce electricity theft would enable the utility to improve electricity services and improve reliability, the net result would be that less additional generation capacity is required.

Annexes

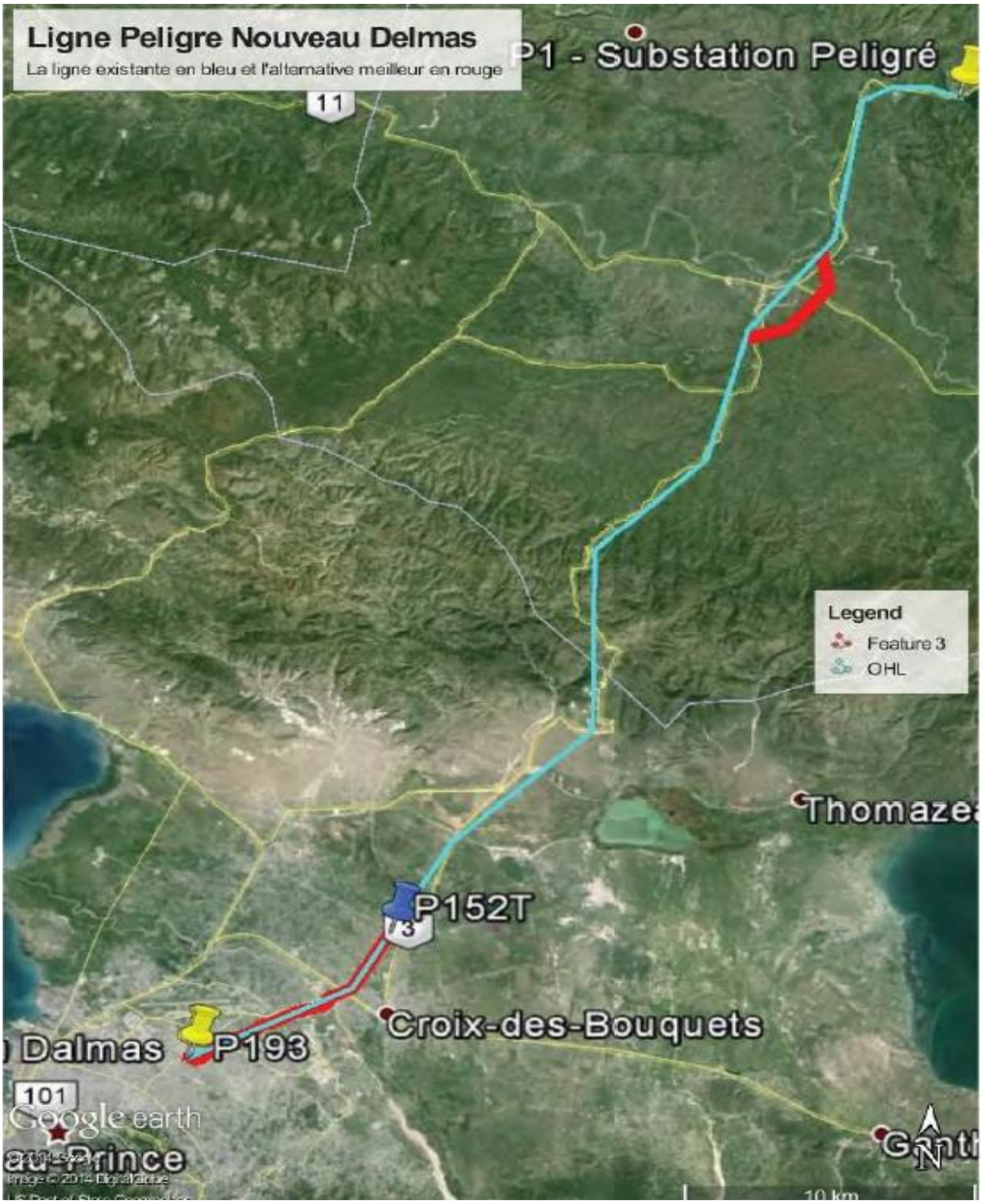
Annex A: Characteristics of the Transmission Line Project

Table A1. System Characteristics

Description	**Data**
System voltage	115 kV
Number and Capacity of circuits in operation	2 x 80 MVA
Maximum Generation Capacity Allowed on Line	80 MW
Length Péligre -PoP	50.7
Length Artibonite-PoP	40.9
Length cable	9.4 lm
Temperature of overhead line conductor	45°C
Resistance of existing line conductor at 55°C	0.3 ohm/km
Resistance of new line conductor at 55°C	0.27 ohm/km
Resistance of new cable at 45°C	0.066 ohm/km
Days overhead line is operated with 2 circuits in operation (N-situation)	351 days/year
Days overhead line is operated with 1 circuit in operation (N-1 situation)	14 days/year

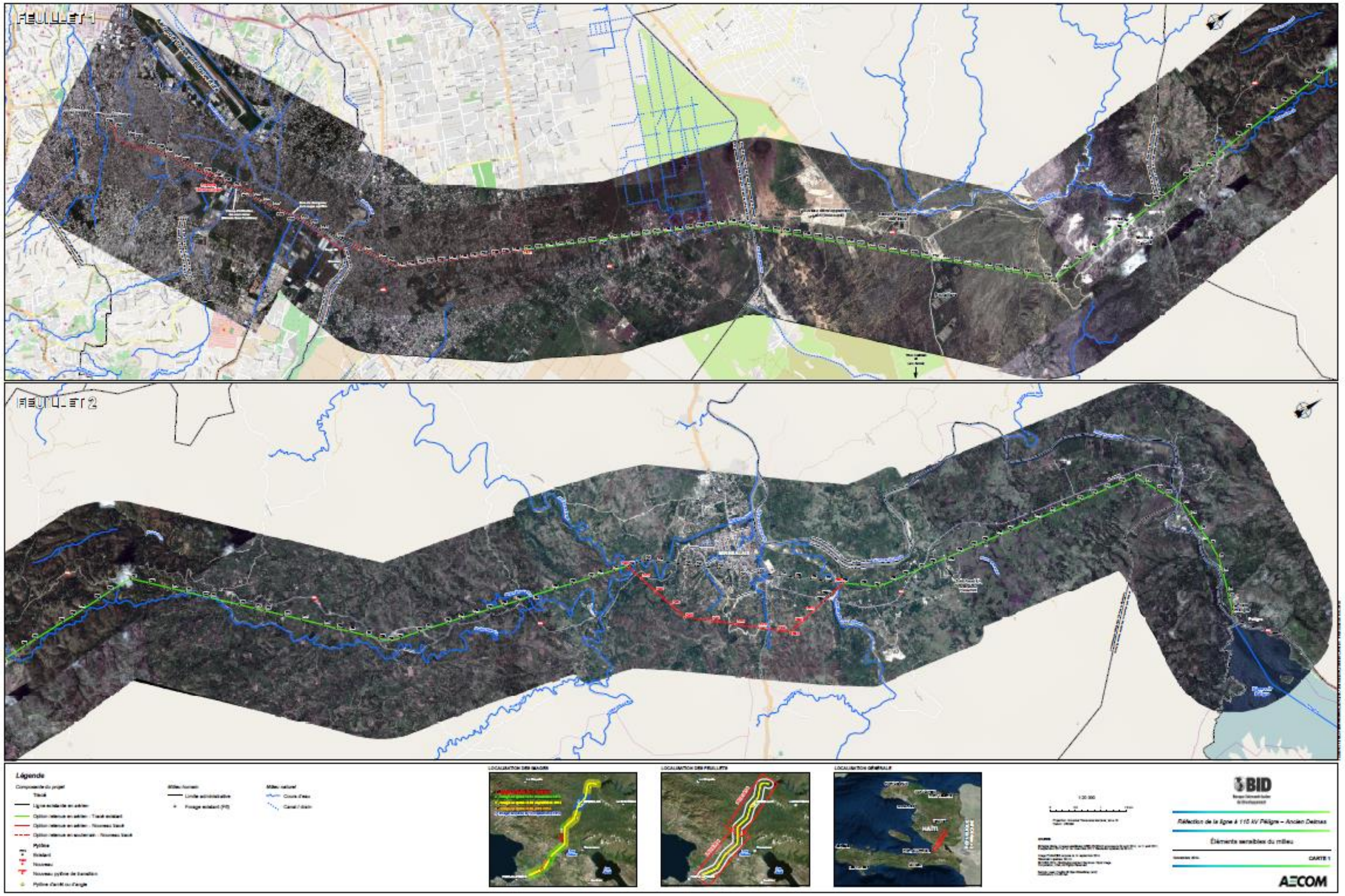
Source: IDB, 2014, p. 14

Figure A1. Location of the Transmission Line Project[106]



Source: MTPTC & EDH, 2014, p. 7

106 http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=39242382



Source: AECOM/IDB, 2014, p.227

Annex B. Variable Cost Components of the Program (US$, 2015 Levels)*

Table B1. Compensation of Families, in the form of Housing Construction and Resettlement Costs (US$, 2015 Levels)

<table>
<tr><th>Department / Province</th><th>District</th><th>City</th><th>Residential (Families)</th><th>Housing Construction Cost/per family (US$)</th><th>Rental Support and Other Costs</th></tr>
<tr><td>Centre</td><td>Mirebalais</td><td>Mirebalais</td><td>4</td><td>25,000</td><td rowspan="4">80,000</td></tr>
<tr><td rowspan="3">Quest</td><td>Croix-des Bouquets</td><td>Thomazeau</td><td>5</td><td rowspan="3">25,000</td></tr>
<tr><td>Croix-des Bouquets</td><td>Croix-des Bouquets</td><td>5</td></tr>
<tr><td>Port-au-Prince</td><td>Tabarre / Delmas</td><td>0</td></tr>
<tr><td>Sub-Total</td><td></td><td></td><td>14</td><td>350,000</td><td>80,000</td></tr>
<tr><td>TOTAL</td><td></td><td></td><td></td><td></td><td>430,000</td></tr>
</table>

Source: MTPTC & EDH, 2014, p, 29-31, p.38

Table B2. Compensation of Farmers, in the Form of Loss of Crop and Trees (Users), or Land (owners) (US$, 2015 Levels)

Size of Company	Number of Farmers	Compensation (Years)	Compensation (US$, day/firm)	Total Compensation (US $)
A. Land Users	**>10**	**1 Year**	**---**	30,000
B. Land Owners	**10**	**---**	**18,000 / each**	180,000
Total Payments to Businesses				**210,000**

Source: MTPTC & EDH, 2014, p, 31, 38

Table B3. Compensation of Loss of Profits During the Construction of Underground Transmission Line (US$, 2015 Levels)

Size of Company	Number of Firms	Working Days Lost	Compensation (US$, day/firm)	Total Compensation (US $)
C. Loss of Profits				
Small: <= 2 employees	23	10	50	1,150
Medium: Between 3 and 10 employees	35	10	200	7,000
Large: >=10 employees	66	10	2,000	132,000
Total	**124**			**140,150**
D. Loss of Property	**Number of Firms**	**Value of Property (US$)**	**Compensation (US$, per firm)**	
Business, located at Croix-des Bouquets Quest	**1**	**80,000**	80,000	80,000
Total Payments to Businesses				**220,150**

<u>*Source:*</u> MTPTC & EDH, 2014, p, 26, 32, and p. 38

Table B4. Direct Labor Costs (US$, 2015 Levels)

Category	Number of Hire (#)	Years of Employment (years)	Real Wage (HTG/month)	Real Annual Wage Increase (%)	Total Cost (HTG)	Total Cost (HTG)	Total Cost (US $)
Skilled							
Engineers	20	4	68,000	2%	75,351,849	90,422,219	1,644,040
Managers	4	4	68,000	2%	15,070,370		
Semi-Skilled							
Technicians	17	4	35,000	2%	32,966,434	55,571,989	1,010,400
Administrator	6	4	35,000	2%	22,605,555		
Unskilled	120	4	10,000	2%	66,486,926	66,486,926	1,208,853
Total	**167**					**212,481,134**	**3,863,293**

(*) Values are gross of personal income taxes. Income taxes are 25%, 15% and 10% for skilled, semi-skilled and unskilled labor, respectively. Real wages are adjusted by the rate of annual increase, and then are adjusted by the rate of inflation to arrive nominal pages paid in each calendar year.

Annex C: Inputs Used in the Calculations of Financial Costs and Benefits

Table C1

Peligre Electricity Transmission Rehabilitation Project - Port-au-Prince, Haiti
Inputs Sheet

Legend

Unit | Input | Calculation | Linked cell

Model Specifications

Currency	
Haitian Gourde	HTG
US Dollars	US $
Thousands of Haitian Gourde	000's HTG
Millions of Haitian Gourde	Million HTG
Thousands of US Dollars	000's US$
Millions of US Dollars	Million US$
Time	
Year	Year
Every X Year, after operation (periodic maintenance)	every "X" Years
Days	Days
Hours	Hours
Distance	
Distance	km
Time, Distance and Currency	
Thousands of USD per km	000' US$/km
Thousands of USD per year	000's US$/year
Energy & Oil	
kilowatt	kW
kilowatt hours	kWh
Megawatt	MW
Megawatt hours	MWh
HTG per kW	HTG/kW
HTG per kWh	HTG/kWh
US$ per kWh	US$/kWh
US$ per kW	US$/kW
Fuel Consumption per kWh of energy produced	liter/kWh
HTG cost of liter of oil	HTG/liter
Emission per liter	kg/liter
Social Cost of Carbon	US$/tonne
Barrel to Liter	157.918
Barrel	bbl
US$ per Barrel	US$ / bbl
US$ per liter	US$/liter
Liter of Oil	liter
Conversions	
1 to Million Conversion	1000000
Thousands to Million Conversion	1000
MWh to kWh Conversion (multiplication)	1000
Liter to Ton	1000
Miscellenous	
Percentage (e.g. transmission loss, load factor)	%
Kilogram	kg
Tonnes	tonne
Number	#
Flag (1 = true, 0 = false)	flag
Conversion Factor	CF

Timing Assumptions

Base Period	2015	Year
Construction Start Year	2015	Year
Construction Length	4	Year
Construction End Year	2019	Year
Operation Start Year	2019	Year
Operation Duration	40	Year
Operation End	2058	Year
Total Months/Year	12	#
Total Days/Year	365	Days
Total Hours/Day	24	Hours

		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Years	Year	2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059

Investment Cost (Real)

			2015	2016	2017	2018
Sub-Component A – Transmission Line Physical Investment Costs						
Supplies of Conductors, Equipments and Materials – Overground Line	10,120	000's US$				
Supplies of Conductors, Equipments and Materials – Underground Line	6,150	000's US$				
Equipment and Supplies for Repairs, Substation and Civil Works	1,930	000's US$				
Insurance, and Handling and Transport Services	540	000's US$				
Sub-Component B – Resettlement and Compensation Costs						
Land Acquisisation and Housing Costs	430	000's US$				
Compensation of Farmers and Land Owners	210	000's US$				
Compensation of Businesses	220	000's US$				
Administration, Management and Monitoring Costs	340	000's US$				
Investment Costs Over-run Factor	0%	%				
Yearly Distribution of Investment Costs / Sub-Component A & Sub-Component B		%	15%	20%	25%	40%
Sub-Component C – Direct Labour Costs						
Skilled Workers						
Number of Engineers		#	20	20	20	20
Monthly wage of Engineers	68	000's HTG				
Number of Managers		#	4	4	4	4
Monthly wage for Managers	68	000's HTG				
Annual increase in real salaries of skilled labour	2%	%				
Semi-Skilled Workers						
Number of Technicians		#	17	17	17	17
Monthly wage of Technicians	35	000's HTG				
Number of Administrators		#	6	6	6	6
Monthly wage for Administrators	35	000's HTG				
Annual increase in real salaries of semi-skilled labour	2%	%				
Unskilled Workers						
Number of Unskilled Workers		#	120	120	120	120
Monthly wage of Unskilled Labour	10	000's HTG				
Annual increase in real salaries of unskilled workers	2%	%				

Investment Financing Shares by Institution

		HRF	IDB
Sub-Component A – Transmission Line Physical Investment Costs			
Supplies of Conductors, Equipments and Materials – Overground Line	%	65%	35%
Supplies of Conductors, Equipments and Materials – Underground Line	%	65%	35%
Equipment and Supplies for Repairs, Substation and Civil Works	%	65%	35%
Insurance, and Handling and Transport Services	%	65%	35%
Sub-Component B – Resettlement and Compensation Costs			
Land Acquisisation and Housing Costs	%	0%	100%
Compensation of Farmers and Land Owners	%	0%	100%
Compensation of Businesses	%	0%	100%
Administration, Management and Monitoring Costs	%	0%	100%
Sub-Component C – Labour Costs During Construction			
Skilled	%	100%	0%
Semi-Skilled	%	100%	0%
Unskilled	%	100%	0%

Depreciation of Capital Assests

Economic service life

Economic life of overground conductors, transmission materials	55	Year
Economic life of underground transmission materials, equipments	55	Year

Annual Operating and Maintenance Cost of Line (Real)

Annual Operating and Maintenance Costs

Overground Lines		
Cost per km	2	*000's US$/year*
Length of exisiting transmission line	50.7	*km*
Length of proposed transmission line	42.7	*km*
Underground Lines		
Annual Regular Maintance Costs	20	*000's US$*
Periodic Maintenance Costs		
Periodic Maintenance Costs	60	*000's US$*
Periodic Maintenance Schedule, starting every "x" years after operation	10	*every "X" Years*

System Load Specifications

Full Load Hours a Year	8760	*Hours*
Fraction of Off-Peak Load Hours (i.e. Baseload Hours)	75%	*%*
Fraction of Peak Load Hours	25%	*%*

Energy Production from Existing and Planned Hydro Generators "with" and "without" Transmission Line Project

1. Existing Peligre Hydro Plant (Peaking and Load Balancing Plant)

without project		
Peligre Hydro Available Capacity	50	*MW*
Capacity Factor in Off- Peak Hours	30%	*%*
Capacity Factor in Peak Hours	100%	*%*
with project		
Peligre Hydro Available Capacity	50	*MW*
Capacity Factor in Off- Peak Hours	30%	*%*
Capacity Factor in Peak Hours	100%	*%*

2. Planned Hydro Generation Capacity (Baseload Plant)

Year when Construction of Planned Hydro Dam Starts	2018	
Number of Years Required for Construction of Plannned Hydro Dam	2	
Year when Planned Hydro Dam Connects to the Line (Year of Commissioning)	2020	*Year*
without project		
Planned Hydro Generation Firm Capacity	20	*MW*
Capacity Factor in Off- Peak Hours	80%	*%*
Capacity Factor in Peak Hours	80%	*%*
with project		
Planned Hydro Generation Firm Capacity	30	*MW*
Capacity Factor in Off- Peak Hours	80%	*%*
Capacity Factor in Peak Hours	80%	*%*

Transmission Line Reliability "with" and "without" Project

Transmission Line Availability (%, load differentiated)

without project		
Off-Peak Load Hours	94.5%	*%*
Peak Load Hours	97.8%	*%*
with project		
Off-Peak Load Hours	97.4%	*%*
Peak Load Hours	98.9%	*%*

Transmission Line Losses (%, load differentiated)

without project		
Line Losses During Off-Peak Load Hours	4%	*%*
Annual Increase in Line Lossses During off-peak Load Hours	0.1%	*%*
Line Losses During Peak Load Hours	8%	*%*
Annual Increase in Line Lossses During Peak Load Hours	0.2%	*%*
with project		
Line Losses During Off-Peak Load Hours	1%	*%*
Annual Increase in Line Lossses During off-Peak Load Hours	0.02%	*%*
Line Losses During Peak Load Hours	2%	*%*
Annual Increase in Line Lossses During Peak Load Hours	0.04%	*%*

Utility Energy Costs and Retail Prices (Real)

ELECTRIC UTILITY SYSTEM MARGINAL AND RETAIL COSTS		
a. Variable Energy Price Components		
Share of Heavy Fuel oil in Wholesale Cost of Energy	70%	%
Average Heavy Fuel Consumption of Diesel Plants (Year 0)	0.24	liter/kWh
Average Reduction in Heavy Fuel Consumption of Plants, per year continious	0.75%	%
Share of Gas oil in Wholesale Cost of Energy	30%	%
Average Gasoil Consumption of Diesel Plants (Year 0)	0.32	liter/kWh
Average Reduction in Gasoil Consumption of Plants, per year continious	0.75%	%
L-R Average System Variable O&M Cost Charges	0.003	US$/kWh
b. Fixed Energy Price Components		
L-R Electricity Transmission Charge	0.02	US$/kWh
L-R Electricity Distribution Charge	0.01	US$/kWh
L-R Average Fixed Charges (e.g. Fixed O&M and Capacity)	0.03	US$/kWh
Change in Capacity Charge	0%	%
COST OF ELECTRICITY GENERATION FROM THE LEAST-EFFICIENT OFF-PEAKING PLANT		
Average Fuel Consumption of the Least Efficient Off-Peaking Plant in the System	0.26	liter/kWh
Average Reduction in Heavy Fuel Consumption of Plants, per year continious	0.75%	%
Average Operation & Maintenance Costs of Least-Efficient Baseload Plant in the System	15.0	US$/kW
Change in O&M Costs of the Least-Effieicient Baseload Plant	0%	%
FUEL PRICE CALCULATIONS for ELECTRIC UTILITY (grid generation)		
L-R Average World Crude Oil Price	50.00	US$ / bbl
Refinery Charges % of World Price, for Heavy Fuel Oil	20%	%
Refinery Charges % of World Price, for Gasoil (Diesel)	10%	%
International Transportation Charges, % of CIF Price	20%	%
Domestic Transportation Charges, % of CIF Price	10%	%

Taxes and Other Charges

On Fixed Capital Items		
Trade Tariff on Imported Capital Items	0%	%
VAT on Imported Capital Items	0%	%
VAT on Local Services (e.g. Port Handling and Transportation)	0%	%
On Petroluem Products		
Import Duty on Petroluem Imports	0%	%
Average Excise Tax on Fuel Purchases	6%	%
Additional Gov't Charges on Fuel Purchases (for utility operations)	0%	%
On Electricity Retail		
Retail Tax on Electricity	5%	%

National Parameters

Electric Utility, EDH, Discount Rate (Financial Analysis)	8%	%
Annual Expected Domestic Inflation Rate (Haiti)	10.0%	%
Annual Expected Foreign Inflation Rate (US)	3%	%
Real Exchange Rate (HTG/US$ year 0)	55	#
Real Exchange Rate Appreciation / Depreciation Factor	0%	%

Annex D. Incremental Energy Flow from Transmission Line

D1. Calculations of Transmission Line Availability ($a_{lt}^{with}, a_{lt}^{without}$)

Total Load in a year: 8,760 (365*24), of which peak load hours are 6,570 and off-peak load hours are 2,190.

Given that:

$$a_{lt}^{with} = \frac{H_{lt} - \theta_{lt}^{with} - \varphi_{lt}^{with}}{H_{lt}} \tag{1}$$

Similarly,

$$a_{lt}^{without} = \frac{H_{lt} - \theta_{lt}^{without} - \varphi_{lt}^{without}}{H_{lt}} \tag{2}$$

where:

t	year of transmission line in operation ($t = 3, \dots, 40$)
l	load period ($l = 2; 1 = off-peak\ and\ 2 = peak\ load$)
H_{lt}	total hours in each demand load of the year (e.g. 8760 total hours in year t, of which 6,570 hours are off-peak load, 2,190 hours are peak load in Haiti)
$a_{lt}^{with}, a_{lt}^{without}$	availability factor of the transmission line at each demand load of the year (%), with and without project, respectively
$\theta_{lt}^{with}, \theta_{lt}^{without}$	number of planned outage hours of the transmission line at each demand load of the year t, with and without project, respectively
$\varphi_{lt}^{with}, \varphi_{lt}^{without}$	number of unplanned outage hours of the transmission line at each demand load of the year t (%), with and without project, respectively

Availability of Transmission Line in Off-Peak and Peak Load Hours

During Off- Peak-Load Hours $l = 1\ (off - peak\ load)$

$$a_{lt}^{with} = \frac{6{,}570 - 168 - 0}{6{,}570} \cong 97.4\% \quad (3)$$

$$a_{lt}^{without} = \frac{6{,}570 - 360 - 0}{6{,}570} \cong 94.5\% \quad (4)$$

During Peak Load Hours $l = 2\ (peak\ load)$

$$a_{lt}^{with} = \frac{2{,}190 - 0 - 24}{2{,}190} \cong 98.9\% \quad (5)$$

$$a_{lt}^{without} = \frac{2{,}190 - 0 - 48}{2{,}190} \cong 97.8\% \quad (6)$$

Therefore,

$\rho_{lt}^{with}, \rho_{lt}^{without}$ transmission losses at each demand load of the year (%)with and without project, respectively

D2. Incremental Energy Transmitted from 70 MW Hydro Plant Firm Capacity (50 MW Existing Peaking Capacity + 20 MW Planned Baseload Hydro Capacity)

$$\Delta\, T_{elt} \approx \underbrace{\sum\nolimits_e \left(\overbrace{H_{lt} \cdot CF_{elt} \cdot K_{et}}^{MWh\ Generation}\right) \cdot \boldsymbol{a_{lt}^{with}} \cdot \left(1-\rho_{lt}^{with}\right)}_{Total\ MWh\ Transmission\ at\ Each\ Load'} - \underbrace{\sum\nolimits_e \left(\overbrace{H_{lt} \cdot CF_{elt} \cdot K_{et}}^{MWh\ Generation}\right) \cdot \boldsymbol{a_{lt}^{without}} \cdot \left(1-\rho_{lt}^{without}\right)}_{Total\ MWh\ Transmission\ at\ Each\ Load}$$

(7)[107]

where:

t	year of transmission line in operation ($t = 3, \dots, 40$)
l	load period ($l = 2; 1 = off - peak\ and\ \ 2 = peak\ load$)
e	generation units connected and will be connected to the unimproved transmission line, and will be re-connected to the rehabilitated transmission line (e.g. 50 MW PHP (serving mostly as peaking load) + 20 MW Planned Hydro Dam (serving as baseload)
H_{lt}	total hours in each demand load of the year (e.g. 8760 total hours in a year, of which 6,570 hours are off-peak load, 2,190 hours are peak load in Haiti)[108]
ΔT_{elt}	net incremental MWh of GRID energy transmitted from generation units connected and will be connected to unimproved transmission line, and will be re-connected to the rehabilitated transmission line (MWh)
$\rho_{lt}^{with}, \rho_{lt}^{without}$	transmission losses at each demand load of the year (%)with and without the project, respectively, $\rho_{lt}^{with} < \rho_{lt}^{without}$ in both periods.
$a_{lt}^{with}, a_{lt}^{without}$	availability factor of the transmission line at each demand load of the year (%), with and without the project, respectively, $a_{lt}^{with} > a_{lt}^{without}$ in both periods.
CF_{elt}	average capacity factor of hydro generators, of 'e' 50 MW Peaking and 20 MW Baseload, at each demand load of the year (%), seasonality in capacity factor is omitted.
K_t^e	firm capacity of the (e) generation units, 50 MW Peaking Hydro and 20 MW Baseload Planned hydro, in each year (MW)

107 The energy generation from 50 MW hydro and 20 MW hydro will be the same with and without the project (see capacity factors presented in Table 6). However, the differences in transmission line losses (ρ_{lt}) and the availability of the transmission line(a_{lt}) captures the additional energy transmitted due to an improved transmission line (see Table 7).

108 See *Load Hours* assumptions.

Table D2.1 Incremental Energy During Off-Peak Load Hours, Transmitted from 70 MW Hydro Capacity

8. INCREMENTAL ENERGY TRANSMISSION DUE TO IMPROVED LINE EFFICIENCY (kWh)			2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Flag for "WITHOUT" Scenario																
Operation End	2058	*Year*														
Operation period		*flag*	1	1	1	1	1	1	...	1	...	1	...	1	...	0
Flag for "WITH" Scenario																
Operation Start Year	2019	*Year*														
Operation End	2058	*Year*														
Operation period		*flag*	0	0	0	0	1	1	...	1	...	1	...	1	...	0
Flag for Planned Hydro Generation Capacity																
Year when Planned Hydro Dam Connects to the Line (Year of Commissioning)	2020	*Year*														
Operation period		*flag*	0	0	0	0	0	1	...	1	....	1	....	1	....	0
1. NET INCREMENTAL ENERGY TRANSMITTED FROM 50 MW EXISTING AND 20 MW PLANNED HYDRO CAPACITY			**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	...	**2030**	...	**2040**	...	**2050**	...	**2059**
A. INCREMENTAL ENERGY IMPACTS DURING OFF-PEAK LOAD HOURS																
Off-Peak Load Hours		*Hours*	6570	6570	6570	6570	6570	6570	...	6570	...	6570	...	6570	...	6570
WITHOUT PROJECT																
Peligre Hydro Plant (Peaking) on Unrehabilitated Transmission Line		*MW*	50	50	50	50	50	50	...	50	...	50	...	50	...	0
Capacity Factor in Off- Peak Hours		*%*	30%	30%	30%	30%	30%	30%	...	30%	...	30%	...	30%	...	30%
Planned Hydro Plant (Baseload) on Unrehabilitated Transmission Line		*MW*	-	-	-	-	-	20	...	20	...	20	...	20	...	-
Capacity Factor in Off- Peak Hours		*%*	80%	80%	80%	80%	80%	80%	...	80%	...	80%	...	80%	...	80%
Transmission Line Availability (%)		*%*	94.5%	94.5%	94.5%	94.5%	94.5%	94.5%	...	94.5%	...	94.5%	...	94.5%	...	94.5%
Line Losses During Off-Peak Load Hours		*%*	4.00%	4.10%	4.20%	4.30%	4.40%	4.50%	...	5.50%	...	6.50%	...	7.50%	...	8.40%
Net Off-Peak Load Energy **Generated** from 50 MW Peligre Hydro Plant		*MWh*	98,550	98,550	98,550	98,550	98,550	98,550	...	98,550	...	98,550	...	98,550	...	0
Net Off-Peak Load Energy **Transmitted** from 50 MW Peligre Hydro Plant		*MWh*	89,405	89,311	89,218	89,125	89,032	88,939	...	88,008	...	87,076	...	86,145	...	0
Net Off-Peak Load Energy **Generated** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	105,120	...	105,120	...	105,120	...	105,120	...	0
Net Off-Peak Load Energy **Transmistted** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	94,868	...	93,875	...	92,881	...	91,888	...	0
WITH PROJECT																
Peligre Hydro Plant (Peaking) on Unrehabilitated Transmission Line		*MW*	50	50	50	50	50	50	...	50	...	50	...	50	...	0
Capacity Factor in Off- Peak Hours		*%*	30%	30%	30%	30%	30%	30%	...	30%	...	30%	...	30%	...	30%
Planned Hydro Plant (Baseload) on Unrehabilitated Transmission Line		*MW*	0	0	0	0	0	20	...	20	...	20	...	20	...	0
Capacity Factor in Off- Peak Hours		*%*	0%	0%	0%	0%	0%	80%	...	80%	...	80%	...	80%	...	80%
Transmission Line Availability (%)		*%*	94.5%	94.5%	94.5%	94.5%	97.4%	97.4%	...	97.4%	...	97.4%	...	97.4%	...	97.4%
Losses on New Transmission Line During Off-Peak Load Hours		*%*	0.00%	0.00%	0.00%	0.00%	1.00%	1.02%	...	1.22%	...	1.42%	...	1.62%	...	0.00%
Transmission Line Losses with Project During Off-Peak Load Hours (incremental analysis)		*%*	4.00%	4.10%	4.20%	4.30%	1.00%	1.02%	...	1.22%	...	1.42%	...	1.62%	...	8.40%
Net Off-Peak Load Energy **Generated** from 50 MW Peligre Hydro Plant		*MWh*	98,550	98,550	98,550	98,550	98,550	98,550	...	98,550	...	98,550	...	98,550	...	0
Net Off-Peak Load Energy **Transmitted** from 50 MW Peligre Hydro Plant		*MWh*	89,405	89,311	89,218	89,125	95,028	95,009	...	94,817	...	94,625	...	94,433	...	0
Net Off-Peak Load Energy **Generated** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	105,120	...	105,120	...	105,120	...	105,120	...	0
Net Off-Peak Load Energy **Transmistted** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	101,343	...	101,138	...	100,933	...	100,728	...	0
INCREMENTAL ENERGY TRANMISSION DURING OFF-PEAK LOAD HOURS OF OPERATION																
Net Incremental Off-Peak Load Energy **Transmistted** from 50 MW Hydro Plant		*MWh*	0	0	0	0	5,996	6,070	...	6,809	...	7,548	...	8,288	...	0
Net Incremental Off-Peak Load Energy **Transmistted** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	6,474	...	7,263	...	8,052	...	8,840	...	0
MWh to kWh Conversion	1000															
Net Incremental Off-Peak Load Energy Transmistted from 50 MW Hydro Plant		*kWh*	0	0	0	0	5,995,782	6,069,714	...	6,809,036	...	7,548,358	...	8,287,681	...	0
Net Incremental Off-Peak Load Energy Transmistted from 20 MW Planned Hydro Plant		*kWh*	0	0	0	0	0	6,474,362	...	7,262,972	...	8,051,582	...	8,840,193	...	0
Net Total Incremental Off-Peak Energy Transmitted from 70 MW Hydro Capacity		*kWh*	0	0	0	0	5,995,782	12,544,076	...	14,072,008	...	15,599,941	...	17,127,873	...	0

Table D2.2 <u>Incremental Energy During Peak Load Hours, Transmitted from 70 MW Hydro Capacity</u>

8. INCREMENTAL ENERGY TRANSMISSION DUE TO IMPROVED LINE EFFICIENCY (kWh)			2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Flag for "WITHOUT" Scenario																
Operation End	2058	*Year*														
Operation period		*flag*	1	1	1	1	1	1	...	1	...	1	...	1	...	0
Flag for "WITH" Scenario																
Operation Start Year	2019	*Year*														
Operation End	2058	*Year*														
Operation period		*flag*	0	0	0	0	1	1	...	1	...	1	...	1	...	0
Flag for Planned Hydro Generation Capacity																
Year when Planned Hydro Dam Connects to the Line (Year of Commissioning)	2020	*Year*														
Operation period		*flag*	0	0	0	0	0	1	...	1	....	1	....	1	....	0
1. NET INCREMENTAL ENERGY TRANSMITTED FROM 50 MW EXISTING AND 20 MW PLANNED HYDRO CAPACITY			**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**...**	**2030**	**...**	**2040**	**...**	**2050**	**...**	**2059**
<u>B. INCREMENTAL ENERGY IMPACTS DURING PEAK LOAD HOURS</u>																
Peak Load Hours		*Hours*	2190	2190	2190	2190	2190	2190	...	2190	...	2190	...	2190	...	2190
<u>WITHOUT PROJECT</u>																
Peligre Hydro Plant (Peaking) on Unrehabilitated Transmission Line		*MW*	50	50	50	50	50	50	...	50	...	50	...	50	...	0
Capacity Factor in Peak Hours		*%*	100%	100%	100%	100%	100%	100%	...	100%	...	100%	...	100%	...	100%
Planned Hydro Plant (Baseload) on Unrehabilitated Transmission Line		*MW*	0	0	0	0	0	20	...	20	...	20	...	20	...	0
Capacity Factor in Peak Hours		*%*	80%	80%	80%	80%	80%	80%	...	80%	...	80%	...	80%	...	80%
Transmission Line Availability (%)		*%*	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	...	97.8%	...	97.8%	...	97.8%	...	97.8%
Line Losses During Peak Load Hours		*%*	8%	8%	8%	9%	9%	9%	...	11%	...	13%	...	15%	...	17%
Net Peak Load Energy **<u>Generated</u>** from 50 MW Peligre Hydro Plant		*MWh*	109,500	109,500	109,500	109,500	109,500	109,500	...	109,500	...	109,500	...	109,500	...	0
Net Peak Load Energy **<u>Transmitted</u>** from 50 MW Peligre Hydro Plant		*MWh*	98,524	98,310	98,095	97,881	97,667	97,453	...	95,311	...	93,169	...	91,027	...	0
Net Peak Load Energy **<u>Generated</u>** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	35,040	...	35,040	...	35,040	...	35,040	...	0
Net Peak Load Energy **<u>Transmistted</u>** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	31,185	...	30,500	...	29,814	...	29,129	...	0
<u>WITH PROJECT</u>																
Peligre Hydro Plant (Peaking) on Unrehabilitated Transmission Line		*MW*	50	50	50	50	50	50	...	50	...	50	...	50	...	0
Capacity Factor in Peak Hours		*%*	100%	100%	100%	100%	100%	100%	...	100%	...	100%	...	100%	...	100%
Planned Hydro Plant (Baseload) on Unrehabilitated Transmission Line		*MW*	0	0	0	0	0	20	...	20	...	20	...	20	...	0
Capacity Factor in Peak Hours		*%*	0%	0%	0%	0%	80%	80%	...	80%	...	80%	...	80%	...	0%
Transmission Line Availability (%)		*%*	97.8%	97.8%	97.8%	97.8%	98.9%	98.9%	...	98.9%	...	98.9%	...	98.9%	...	97.8%
Line Losses During Peak Load Hours		*%*	0.00%	0.00%	0.00%	0.00%	2.00%	2.04%	...	2.44%	...	2.84%	...	3.24%	...	0.00%
Transmission Line Losses with Project During Peak Load Hours (incremental analysis)		*%*	8.00%	8.20%	8.40%	8.60%	2.00%	2.04%	...	2.44%	...	2.84%	...	3.24%	...	16.80%
Net Peak Load Energy **<u>Generated</u>** from 50 MW Peligre Hydro Plant		*MWh*	109,500	109,500	109,500	109,500	109,500	109,500	...	109,500	...	109,500	...	109,500	...	0
Net Peak Load Energy **<u>Transmitted</u>** from 50 MW Peligre Hydro Plant		*MWh*	98,524	98,310	98,095	97,881	106,130	106,086	...	105,653	...	105,220	...	104,787	...	0
Net Peak Load Energy **<u>Generated</u>** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	35,040	...	35,040	...	35,040	...	35,040	...	0
Net Peak Load Energy **<u>Transmistted</u>** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	33,948	...	33,809	...	33,670	...	33,532	...	0
<u>INCREMENTAL ENERGY TRANMISSION DURING OFF-PEAK LOAD HOURS OF OPERATION</u>																
Net **<u>Incremental</u>** Peak Load Energy **<u>Transmistted</u>** from 50 MW Planned Hydro Plant		*MWh*	0	0	0	0	8,463	8,633	...	10,342	...	12,051	...	13,759	...	0
Net **<u>Incremental</u>** Peak Load Energy **<u>Transmistted</u>** from 20 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	2,763	...	3,309	...	3,856	...	4,403	...	0
MWh to kWh Conversion	1000															
Net Incremental Peak Load Energy Transmistted from 50 MW Planned Hydro Plant		*kWh*	0	0	0	0	8,462,598	8,633,462	...	10,342,100	...	12,050,738	...	13,759,376	...	0
Net Incremental Peak Load Energy Transmistted from 20 MW Planned Hydro Plant		*kWh*	0	0	0	0	0	2,762,708	...	3,309,472	...	3,856,236	...	4,403,000	...	0
Net Incremental Peak Energy Transmitted from 70 MW Hydro Capacity		*kWh*	0	0	0	0	8,462,598	11,396,170	...	13,651,572	...	15,906,974	...	18,162,376	...	0

i) <u>Off-Peak Load Energy Savings from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity</u>

ii) <u>Incremental Peak Load Energy from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity</u>

Table D2.3

10. FUEL SAVINGS (Liters) & INCREMENTAL ENERGY TRANSMISSION (kWh)		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Off-Peak Energy Incremental Energy Transmission From 70 MW Hydro Capacity Due to Improved Transmission Line															
Net Total Incremental Off-Peak Energy Transmitted from 70 MW Hydro Capacity	*kWh*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible],995,782	[illegible]2,544,076	...	[illegible]4,072,008	...	[illegible]5,599,941	...	[illegible]7,127,873	...	[illegible]
Net Total Incremental Energy Displaced In the System, from the Least-effiicient plant	*kWh*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible],995,782	[illegible]2,544,076	...	[illegible]4,072,008	...	[illegible]5,599,941	...	[illegible]7,127,873	...	[illegible]
Average Fuel Consumption of the Least Efficient Off-Peaking Plant In the System	*liter/kWh*	**0.260**	**0.258**	**0.256**	**0.254**	**0.252**	**0.250**	**...**	**0.232**	**...**	**0.215**	**...**	**0.200**	**...**	**0.187**
Fuel Saved from the Highest MC Baseload Plant	*liter*	**0**	**0**	**0**	**0**	**1,512,660**	**3,140,976**	**...**	**3,268,039**	**...**	**3,360,154**	**...**	**3,421,723**	**...**	**0**
Incremental Peak-Load Energy Transmission from a Total of 70 MW Hydro Capacity Due to Improved Transmission Line															
Net Incremental Peak Energy Transmitted from 70 MW Hydro Capacity	*kWh*	**0**	**0**	**0**	**0**	**8,462,598**	**11,396,170**	**...**	**13,651,572**	**...**	**15,906,974**	**...**	**18,162,376**	**...**	**0**

D3. Incremental Energy Transmitted from ADDITIONAL 10.00 MW Planned Baseload Hydro Generation Plant - Due to ENHANCED Transmission Capacity

$$q'_{pt} = \underbrace{\textstyle\sum_p \sum_h \left(H_{lt} \cdot CF_{plt} \cdot K'_{pt}\right) \cdot a_{lt}^{with} \cdot \left(1 - \rho_{lt}^{with}\right)}_{Total\ MWh\ of\ Energy\ Transmission\ in\ BOTH\ Load} \tag{8}$$

where:

q'_{pt} — net annual incremental MWh of energy transmitted from extra planned (p) generation in year t (MWh)

H_{lt} — total hours in each demand load of the year (e.g. 8760 total hours in a year, of which 6,570 hours are off-peak load, 2,190 hours are peak load in Haiti)[109]

CF_{plt} — capacity factor of the extra planned generator at each demand load of the year (%)[110]

K'_{pt} — extra generation capacity from enhanced transmission capacity in year t (MW)

ρ_{lt}^{with} — transmission losses at of rehabilitated transmission line, at each demand load of the year (%)

a_{lt}^{with} — availability factor of rehabilitated transmission line at each demand load of the year (%)

109 See *Project Variables and Assumptions*.

110 In the case of many generators operating on the same transmission line, the capacity factors can be different as transmission line might induce better dispatching on the system. In our project, this is not the case (see Table 6).

Table D3.1. Incremental Energy During Peak and Off-Peak Load Hours, Transmitted from Additional 10 MW Baseload Hydro Capacity

9. INCREMENTAL ENERGY TRANSMISSION DUE TO IMPROVED LINE CAPACITY (kWh)			2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Flag for "WITH" Scenario																
Operation Start Year	2019	*Year*														
Operation End	2058	*Year*														
Operation period		*flag*	0	0	0	0	1	1	...	1	...	1	...	1	...	0
Flag for Planned Hydro Generation Capacity																
Year when Planned Hydro Dam Connects to the Line (Year of Commissioning)	2020	*Year*														
Operation period		*flag*	0	0	0	0	0	1	....	1	....	1	....	1	....	0
NET INCREMENTAL ENERGY TRANSMITTED FROM ADDITIONAL 10 MW BASELOAD HYDRO CAPACITY																
A. INCREMENTAL ENERGY IMPACTS DURING OFF-PEAK LOAD HOURS																
Off-Peak Load Hours		*Hours*	6,570	6,570	6,570	6,570	6,570	6,570	...	6,570	...	6,570	...	6,570	...	6,570
WITH PROJECT																
Incremental Hydro capacity on Rehabilitated Transmission Line		*MW*	0	0	0	0	0	10	...	10	...	10	...	10	...	0
Capacity Factor in Off-Peak Hours		*%*	0%	0%	0%	0%	0%	80%	...	80%	...	80%	...	80%	...	80%
Transmission Line Availability (%)		*%*	94.5%	94.5%	94.5%	94.5%	97.4%	97.4%	...	97.4%	...	97.4%	...	97.4%	...	97.4%
Line Losses During Off-Peak Load Hours		*%*	4.00%	4.10%	4.20%	4.30%	1.00%	1.02%	...	1.22%	...	1.42%	...	1.62%	...	8.40%
Net Off-Peak Load Energy **Generated** from Additional 10 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	52,560	...	52,560	...	52,560	...	52,560	...	0
Net Off-Peak Load Energy **Transmitted** from Additional 10 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	50,671	...	50,569	...	50,466	...	50,364	...	0
B. INCREMENTAL ENERGY IMPACTS DURING PEAK LOAD HOURS																
Peak Load Hours		*MWh*	2,190	2,190	2,190	2,190	2,190	2,190	...	2,190	...	2,190	...	2,190	...	2,190
WITH PROJECT																
Incremental Hydro capacity on Rehabilitated Transmission Line		*MW*	0	0	0	0	0	10	...	10	...	10	...	10	...	0
Capacity Factor in Peak Hours		*%*	0%	80%	80%	80%	80%	80%	...	80%	...	80%	...	80%	...	80%
Transmission Line Availability (%)		*%*	98%	98%	98%	98%	99%	99%	...	99%	...	99%	...	99%	...	98%
Line Losses During Peak Load Hours		*%*	8%	8%	8%	9%	2%	2%	...	2%	...	3%	...	3%	...	17%
INCREMENTAL ENERGY FROM ADDITIONAL 10 MW HYDRO BASELOAD CAPACITY																
Net Peak Load Energy **Generated** from Additional 10 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	17,520	...	17,520	...	17,520	...	17,520	...	0
Net Peak Load Energy **Transmitted** from Additional 10 MW Planned Hydro Plant		*MWh*	0	0	0	0	0	16,974	...	16,904	...	16,835	...	16,766	...	0
Net Incremental Energy Transmissted (Delivered) from Extra 10 MW Generation Capacity		*MWh*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	67,645	...	67,473	..	67,302	..	67,130	..	[illegible]
Net Incremental Energy Transmissted (Delivered) from Extra 10 MW Generation Capacity		*kWh*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	67,645,070	...	67,473,374	..	67,301,678	..	67,129,982	..	[illegible]

Annex E: Estimations of Wholesale and Retail Prices of Electricity[111]

Marginal Cost of Electricity Generation (HTG/kWh)

$$\bar{P}_t^w = \boldsymbol{\omega} + (1-\omega)\underbrace{\left[s_f\left(\beta_t^f \cdot P_t^f\right) + s_d(\beta_t^d \cdot P_t^d)\right] + VC_t}_{\lambda_t} \tag{9}$$

where:

t year

$\bar{P}_t^w$ average wholesale (w) price of electricity in year t (HTG/kWh)

ω_t fraction of energy delivered from generation units to distribution loads (%) – increase in this parameter will increase cost-recovery of the electric utility.[112]

$1-\omega_t$ fraction of energy lost on transmission and distribution lines (%)

s_f share of heavy fuel oil in total wholesale cost in year t (%) - assumed to be constant at 70%

β_t^f average variable fuel consumption of heavy fuel oil plants in year t (liter/kWh)

P_t^f domestic price of heavy fuel oil for electricity generation (HTG/liter)

s_d share of diesel oil in total wholesale cost in year t (%) - assumed to be constant at 30%

β_t^d average variable fuel consumption of diesel oil plants (liter/kWh)

P_t^d domestic price of diesel oil for electricity generation (HTG/liter)

VC_t average system variable charges (e.g. O&M charges) for electricity generation (HTG/kWh)

λ_t average system variable fuel and variable O& M cost of electricity generation (HTG/kWh) – subject to tax at the retail level.

---

111 Haiti will experience ongoing grid rehabilitation in its electricity sector. The rehabilitations will be in the form of higher penetration of more efficient generation technologies (reflected in beta parameters) and improved transmission/distribution line operations (reflected in omega parameter).

112 It includes both technical and non-technical losses (theft, inability to bill etc.). In our analysis, we take into account technical line availability and reduction in mechanical losses.

Retail Pricing of Electricity (HTG/kWh)

$$\bar{P}_t^r = \lambda_t \cdot (1 + \tau_t) + \underbrace{FC_t + \gamma_t + \delta_t}_{fixed\ additives} \quad (10)$$

where:

$\bar{P}_t^r$ average retail (r) price of electricity in year t (HTG/kWh)

λ_t average system fuel cost of electricity generation (HTG/kWh)

FC_t long-run average fixed charges (e.g. fixed O&M, fixed capacity charges etc) of electricity generation, presented in (HTG/kWh)

γ_t long-run average fixed cost of transmission charge (HTG/kWh), a component of network charge

δ_t long-run average fixed distribution charge (HTG/kWh), a component of fixed network charge

τ_t state-mandated tax on electricity consumption (%) - assumed to be constant at 5%

Constant Variables and Assumptions

$s_f = 70\%$ and $s_d = 30\%$

$VC_t = 0.003\ US\$/kWh$

$\gamma = 0.02\ US\$/kWh$

$\delta = 0.01\ US\$kWh$

$C_t = 0.033 US\$/kWh$

$\tau_t = 5\%$.

Time-Dependent Variable and Assumptions

$\beta_{t=0}^{f}$= 0.24 and it is declining at a rate of 0.75% per year

$\beta_{t=0}^{d}$ = 0.32and is declining at a rate of 0.75 % per year

$P_{t=0}^{f}$= 28 HTG/liter – subject to risks of world fuel price volatility and exchange rate. Therefore, the price of HFO is calculated annually.

$P_{t=0}^{d}$= 26 HTG/liter – subject to world risks of world fuel price volatility and exchange rate. Similar to HFO, the price of diesel oil is calculated annually.

Table E1. Fuel Cost Calculations for Electricity Generation **(UTILITY)**

Fuel Cost Assumptions		
bbl/liter conversion	159	
HTG/US$ (2015 Average)	55	
Crude Oil Price (1974-2015 Average)	50.00	US $/bbl
Crude Oil Price	**0.31**	**US $liter**
Gas Oil Price		
Refinery Charges	10%	of World Crude Oil Price
International Transport Charges	20%	of World Crude Oil Price
CIF Price Diesel Oil	0.41	US $/liter
CIF Price Diesel Oil	22.4	HTG/liter
+Local Transport Cost	10%	of CIF Price
Wholesale Price	24.5	HTG/liter
Excise Tax (6%)	1.5	HTG/liter
Other Gov't Charges (0%)	--	%of wholesale price
Retail Price of Gas Oil	**26.1**	**HTG/liter**
Heavy-Fuel Oil Price		
Refinery Charges	20%	of World Crude Oil Price
International Transport Charges	20%	of World Crude Oil Price
CIF Price Diesel Oil	0.44	US $/liter
CIF Price Diesel Oil	24.1	HTG/liter
+Local Transport Cost	10%	of CIF Price
Wholesale Price	26.5	HTG/liter
Excise Tax (6%)	1.6	HTG/liter
Other Gov't Charges (0%)	--	%of wholesale price
Retail Price of HFO	**28.2**	**HTG/liter**

Year	Average Real Price of Crude Oil (US$/Barrel)
1974	43.88
1975	44.80
1976	41.23
1977	41.87
1978	39.23
1979	53.35
1980	77.48
1981	77.42
1982	66.02
1983	55.48
1984	52.69
1985	49.51
1986	26.07
1987	32.41
1988	26.12
1989	30.87
1990	37.03
1991	31.55
1992	29.49
1993	25.86
1994	23.58
1995	24.78
1996	29.18
1997	26.75
1998	18.55
1999	24.33
2000	37.45
2001	31.38
2002	31.07
2003	36.33
2004	47.03
2005	62.13
2006	70.49
2007	75.15
2008	101.61
2009	62.41
2010	79.39
2011	92.97
2012	90.61
2013	92.85
2014	87.20
2015	45.37
L-R Average	**49.36**

Table E2. *Dynamic Electricity Tariff Calculations for Utility Sales*

12. PRODUCTION COST FROM THE LEAST-FUEL EFFICIENT OFF-PEAK PLANT (Nominal) - off-peak load be			2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Electricity Generation Cost from the Least-Efficient Utility Plant Running Off-Peak Load Hours																
i) Variable Fuel Cost																
Price Heavy Fuel Oil for Utility Level Electricity Generation	*HTG/liter*		28	31	34	38	42	46	...	119	...	308	...	799	...	1884
ii) Variable O&M Costs (non-fuel)																
Average Operation & Maintenance Costs of Least-Efficient Baseload Plant in the System																
Average Operation & Maintenance Costs of Least-Efficient Baseload Plant in the System	*US$/kW*	15														
Change in O&M Costs of the Least-Effieicient Baseload Plant	*%*	0														
Baseload Hours	*Hours*	8760														
Annual Average O&M Costs of the Least Efficient Plant (Real)	*US$/kW*		15	15	15	15	15	15	...	15	...	15	...	15	...	15
Annual Average O&M Costs of the Least Efficient Plant (Nominal)	*US$/kW*		15	15	16	16	17	17	...	23	...	31	...	42	...	55
Annual Average O&M Costs of the Least Efficient Plant (Nominal)	*HTG/kW*		825	908	998	1098	1208	1329	...	3446	...	8939	...	23185	...	54668
Annual Average O&M Costs of the Least Efficient Plant (Nominal)	*HTG/kWh*		0.094	0.104	0.114	0.125	0.138	0.152	...	0.393	...	1.020	...	2.647	...	6.241

13. UTILITY ENERGY TARIFF (Nominal, HTG/kWh) - for peak-load benefit calculations			2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
A. Electricity Generation Costs - System Marginal Cost																
i) Variable Fuel Cost																
Price Heavy Fuel Oil for Utility Level Electricity Generation	*HTG/liter*		28.43	31.27	34.40	37.84	41.62	45.78	...	118.75	...	308.00	...	798.86	...	1,883.67
Share of Heavy Fuel oil in Wholesale Cost of Energy	*%*		70%	70%	70%	70%	70%	70%	...	70%	...	70%	...	70%	...	70%
Average Heavy Fuel Consumption of Diesel Plants (Year 0)	*liter/kWh*		0.24	0.24	0.24	0.23	0.23	0.23	...	0.21	...	0.20	...	0.18	...	0.17
Price Gasoil for Utility Level Electricity Generation	*HTG/liter*		26.40	29.04	31.94	35.13	38.65	42.51	...	110.26	...	286.00	...	741.80	...	1749.13
Share of Gas oil in Wholesale Cost of Energy	*%*		30%	30%	30%	30%	30%	30%	...	30%	...	30%	...	30%	...	30%
Average Gasoil Consumption of Diesel Plants (Year 0)	*liter/kWh*		0.32	0.32	0.32	0.31	0.31	0.31	...	0.29	...	0.27	...	0.25	...	0.23
Variable Fuel Cost for Electricity Generation	*HTG/kWh*		7.31	7.98	8.71	9.51	10.38	11.34	...	27.27	...	65.61	...	157.84	...	347.79
ii) Variable O&M Costs (non-fuel)																
Foreign Price Index (US)	*#*		1.00	1.03	1.06	1.09	1.13	1.16	...	1.56	...	2.09	...	2.81	...	3.67
Expected Nominal Exchange Rate (HTG/US$)	*#*		55.00	58.74	62.73	66.99	71.55	76.41	...	147.47	...	284.61	...	549.29	...	992.67
L-R Average System Variable O&M Cost Charges	*US$/kWh*		0.003	0.003	0.003	0.003	0.003	0.003	...	0.003	...	0.003	...	0.003	...	0.003
L-R Average Fixed O&M Cost Charges (Nominal, US$)	*US$/kWh*		0.00	0.00	0.00	0.00	0.00	0.00	...	0.00	...	0.01	...	0.01	...	0.01
L-R Average Fixed O&M Cost Charges (Nominal, HTG)	*HTG/kWh*		0.17	0.18	0.20	0.22	0.24	0.27	...	0.69	...	1.79	...	4.64	...	10.93
A. Wholesale Electricity Generation Costs, Inc variable fuel and variable O&M Costs = (i)+(ii)	***HTG/kWh***		7.47	8.16	8.91	9.73	10.63	11.60	...	27.96	...	67.40	...	162.48	...	358.73
B. Fixed Additives																
Foreign Price Index (US)	*#*		1.00	1.03	1.06	1.09	1.13	1.16	...	1.56	...	2.09	...	2.81	...	3.67
Expected Nominal Exchange Rate (HTG/US$)	*#*		55.00	58.74	62.73	66.99	71.55	76.41	...	147.47	...	284.61	...	549.29	...	992.67
L-R Electricity Transmission Charge	*US$/kWh*		0.02	0.02	0.02	0.02	0.02	0.02	...	0.02	...	0.02	...	0.02	...	0.02
L-R Electricity Transmission Charge (Nominal, US$)	*US$/kWh*		0.02	0.02	0.02	0.02	0.02	0.02	...	0.03	...	0.04	...	0.06	...	0.07
L-R Electricity Transmission Charge (Nominal, HTG)	*HTG/kWh*		1.10	1.21	1.33	1.46	1.61	1.77	...	4.59	...	11.92	...	30.91	...	72.89
L-R Electricity Distribution Charge	*US$/kWh*		0.01	0.01	0.01	0.01	0.01	0.01	...	0.01	...	0.01	...	0.01	...	0.01
L-R Electricity Distribution Charge (Nominal, US$)	*US$/kWh*		0.01	0.01	0.01	0.01	0.01	0.01	...	0.02	...	0.02	...	0.03	...	0.04
L-R Electricity Distribution Charge (Nominal, HTG)	*HTG/kWh*		0.55	0.605	0.6655	0.73205	0.805255	0.885781	...	2.297486	...	5.9590883	...	15.45634	...	36.44524
L-R Average Fixed Charges (e.g. Fixed O&M and Capacity)	*US$/kWh*		0.03	0.03	0.03	0.03	0.03	0.03	..	0.03	..	0.03	..	0.03	..	0.03
L-R Average Capacity Charge (Nominal, US$)	*US$/kWh*		0.03	0.03	0.03	0.03	0.03	0.03	...	0.05	...	0.06	...	0.08	...	0.11
L-R Average Capacity Charge (Nominal, HTG)	*HTG/kWh*		1.65	1.82	2.00	2.20	2.42	2.66	...	6.89	...	17.88	...	46.37	...	109.34
B. Total Fixed Charges (Nominal, HTG) = A+B+C	*HTG/kWh*		3.3	3.6	4.0	4.4	4.8	5.3	...	13.8	...	35.8	...	92.7	...	218.7
ELECTRICITY TARIFF (HTG/kWh) = A+B																
Average Retail Price of Electricity (before tax) A+B	*HTG/kWh*		10.77	11.79	12.91	14.12	15.46	16.92	...	41.75	...	103.15	...	255.21	...	577.40
Retail Tax on Electricity	%	5%														
Taxes on Energy Consumption = A * tax%	*HTG/kWh*		0.37	0.41	0.45	0.49	0.53	0.58	...	1.40	...	3.37	...	8.12	...	17.94
Average Retail Price of Electricity (with tax) - for gross sales revenue calculations	*HTG/kWh*		11.15	12.20	13.35	14.61	15.99	17.50	...	43.15	...	106.52	...	263.34	...	595.34

Annex F.Valuation of Financial Benefits

1. Financial Value of Production Cost Savings During Off-Peak Load Hours

The production cost savins are generated from incremental transmission from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity.

$\Delta T_{elt} > 0$ in both periods (see Annex D2, equation 7, and Annex Table D2.3)

where $l = 2;\ l = 1\ (off-peak\ load), l = 2\ (peak\ load)$

<u>During off-peak load hours; $l = 1; off-peak\ load$</u>

$$\Delta T_{elt} = -\Delta q_{zlt} \qquad \forall_{t,l=1} \qquad (11)$$

where:

ΔT_{elt} — <u>net incremental off-peak GRID energy transmitted</u> from 70 MW generation units connected and will be connected to <u>unimproved</u> transmission line, and will be re-connected to the <u>rehabilitated</u> transmission line (kWh)

z — the least-fuel efficient power plant running elsewhere in the system during off-peak load hours

$-\Delta q_{zlt}$ — the amount of energy displaced from least-fuel efficient plant during off-peak load hours (kWh) (negative sign indicates displacement or say reduction)

Liter of fuel consumption of the any plant for each kWh (or per kWh) is known. Therefore, total fuel savings in liter can be computed as follows[113]:

$$F_t^f = \beta_{zt}^f \cdot \Delta q_{zlt} \qquad \forall_t \qquad (12)$$

where:

F_t^f — the total amount of fuel displaced from least-fuel efficient plant during off-peak load hours (liters)

β_{zt}^f — fuel consumption of the least-fuel efficient plant during off-peak load hours (liters/kWh), assumed to be always heavy fuel oil ‘f’ during the life-time of the project.

113 See Annex D, Table D2.1 and D2.3.

Δq_{zlt} the amount of energy displaced from least-fuel efficient plant during off-peak load hours (kWh)

Hence, the financial value of production cost savings are as follows:

<u>*Financial Value of Fuel Savings*</u>

$$\boldsymbol{FV_t^f = F_{lt}^f \cdot P_t^f} \qquad \forall_{t,l=1} \qquad \textbf{(13)}$$

where:

FV_t^f financial value of fuel savings in year t (HTG)

F_t^f the total amount of heavy fuel oil displaced from the least-fuel efficient plant running during off-peak load hours in year t (liters)

P_t^f cost of heavy fuel oil (HFO) for electricity generation in year t (HTG/liter)

<u>*Financial Value of O&M Cost Savings*</u>

$$\boldsymbol{FV_t^m = M_{zt} \cdot -\Delta q_{zlt}} \qquad \forall_{t,l=1}$$

where:

FV_t^m financial value of O&M cost savings in year t (HTG)

M_{zt} variable O&M expense of the least-fuel efficient plant, expressed in HTG/kWh.

$-\Delta q_{zlt}$ the amount of energy displaced from least-fuel efficient plant during off-peak load hours (kWh) (negative sign indicates displacement or say reduction)

Therefore, total production cost savings of the electric utility is:

$$\boldsymbol{FV\ of\ Production\ Cost\ Savings\ (HTG) = FV_t^f + FV_t^m} \qquad \forall_{t,l=1} \qquad \textbf{(14)}$$

2. *Financial Value of Incremental Peak-Load Sales Revenue*

The incremental peak load sales, valued at electricity price, are generated from incremental transmission from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity.

During peak load hours; $l = 2$; *peak load* (see Annex D2, equation 7, and tables D2.2 and D2.3)

$$\Delta T_{elt} = +\Delta D_{lt} \qquad \forall_{t,l=2} \tag{15}$$

ΔT_{elt} net incremental peak-load GRID energy transmitted from generation units connected and will be connected to unimproved transmission line, and will be re-connected to the rehabilitated transmission line (kWh), and equal to the, ΔD_{lt}, the additional amount of peak energy consumed from GRID during peak load hours (kWh), equivalent to amount of peak energy reduced from own-generation sources (economic analysis)

Hence, the financial and economic values of additional sales during peak-load hours are equal to:

$$\boldsymbol{FV_t^s = \Delta D_{lt} \cdot \bar{P}_t^r} \qquad \forall_{t,l=2} \tag{16}$$

where:

FV_t^s financial value of additional peak sales in year t (HTG)

$\bar{P}_t^r$ average retail energy price (HTG/kWh)[114]

3. Value of Transmission Line from Additional Generation Capacity, from incremental generation from 10 MW Planned Baseload Hydro Capacity

From calculations in Annex D3, equation 8, and Annex table D3.1)

$$\boldsymbol{FV_t^p = q'_{pt} \cdot \gamma_t} \qquad \forall_t \tag{17}$$

where:

FV_t^p financial value of additional power from enhanced transmission capacity (HTG), value of avoided transmission cost

q'_{pt} net annual incremental kWh of energy transmitted from extra planned (p) generation in year t (kWh)

γ_t average (and fixed) long-run transmission charge (HTG/kWh), fixed component of network charge.

114 See Annex D.

Annex G: Parameters for the Estimation of the Economic Costs and Benefits

Table G1.

Legend

		Unit	Input	Calculation	Output	Linked cell

INPUTS FOR ECONOMIC ANALYSIS

Electricity Generation Costs from Self-Generation (Real)		
a. Variable Energy Price Components		
Average fuel consumption of small diesel generator	0.404	*liter/kWh*
Reduction in Average Diesel Fuel Consumtion of Small Own-Gene	0.50%	*%*
b. Fixed Energy Price Components		
Average Capital Cost for Self-Generation (i.e. small generator)	0.02	*US$/kWh*
Change in Capital Cost of Small Generators (i.e. reduction)	0%	*%*
Emissions from Electricity Generation		
Emission Intensity of Fuels		
Average Carbon Emission of HFO	2.31	*kg/liter*
Average Carbon Emission of Diesel (gasoil)	2.68	*kg/liter*
Taxes and Other Charges (for Conversion Factor Estimates)		
On Fixed Capital Items		
Trade Tariff on Imported Capital Items	0%	*%*
VAT on Imported Capital Items	0%	*%*
VAT on Local Services (e.g. Port Handling and Transportation)	0%	*%*
Labour (i.e Income Taxes on Gross Nominal Annual Income)		
Skilled Labour	15%	*%*
Semi-Skilled	10%	*%*
Unskilled	0%	*%*
On Petroluem Products		
Import Duty on Petroluem Imports	0%	*%*
Average Excise Tax on Fuel Purchases	6%	*%*
Additional Gov't Charges on Fuel Purchases (for private consump	40%	*%*
National Parameters		
Economic Opportunity Cost of Kapital (EOCK)	8%	*%*
Foreign Exchange Premium (FEP)	5.75%	*%*
Non-Tradable Premium (NTP)	0.75%	*%*
Social Cost of Carbon	20	*US$/tonne*
Local Benefits of Carbon Reductions	0.1%	*%*
Average Tax Distortion (d*), for Conversion Factor Calculations	4%	*%*

Annex H: Estimates for Marginal Cost of Self-Generation

H.1 Parameters (Inputs and Assumptions)

H1.1 Fuel Cost Calculations for Electricity Generation (OWN-GENERATION)

Table H1. Fuel Cost Assumptions

Fuel Cost Assumptions		
bbl/liter conversion	159	
HTG/US$ (2015 Average)	55	
Crude Oil Price (1974-2015 Average)	50.0	US $/bbl
Crude Oil Price	**0.31**	**US $liter**

Diesel Oil Price		
Refinery Charges	20%	of World Crude Oil Price
International Transport Charges	10%	of World Crude Oil Price
CIF Price Diesel Oil	0.41	US $/liter
CIF Price Diesel Oil	22.4	HTG/liter
+Local Transport Cost	10%	of CIF Price
Wholesale Price	24.5	HTG/liter
Excise Tax (6%)	1.5	HTG/liter
Other Gov't Charges (40%)	9.8	%of wholesale price
Retail Price of Diesel Oil	**35.9**	**HTG/liter**

Table H2. Plant Efficiency

Generator (A)	% Ownership (B)	Capacity (kW) (C)	Fuel Type (D)	Capital Costs (HTG) (E)	Lifetime (years) (F)	Load Hours (G)	Average Energy Content of Diesel (kj/liter) (H)	kWh/kj (I)	Average Fuel Efficiency of Generator (J)
Self-Gen 1	5%	5	Diesel	236,500	10	40%	37,100	3,600	15%
Self-Gen 2	5%	10	Diesel	372,900	12	40%			18%
Self-Gen 3	28%	15	Diesel	440,000	15	40%			22%
Self-Gen 4	18%	20	Diesel	460,625	15	40%			26%
Self-Gen 5	20%	25	Diesel	574,750	15	40%			26%
Self-Gen 6	13%	30	Diesel	607,750	15	40%			28%
Self-Gen 7	13%	40	Diesel	660,000	15	40%			30%

Table H3. Fuel Cost Calculations[115]

Load % **K = 8,760* G**	Capital Costs (HTG/kW) **L= (E/C)**	Annualised Capital Cost ($/kW) **M = PMT (interest rate, F, -L)**	Annualised Capital Cost (HTG/kWh) **N= M/K**	Fuel Consumption (liter/kWh) **O= {(C*I)/(J*I)}/D**	Fuel Cost (HTG/liter) **P***	Weighted Average Fuel Consumption (liter/ kWh) **Q =SUM(Bi,Oi))**	Weighted Average Capital Cost (HTG/kWh) **R = SUM(Bi,Ni)**	Weighted Average Fuel Cost (HTG/kWh) **S=P*Q**
3,504	47300	8371	2.389	0.647				
3,504	37290	6020	1.718	0.539				
3,504	29333	4307	1.229	0.441				
3,504	23031	3382	0.965	0.373	35.89	0.404	**1.097**	**14.511**
3,504	22990	3375	0.963	0.373				
3,504	20258	2974	0.849	0.347				
3,504	16500	2423	0.691	0.323				

H1.2 Estimations

$$\overline{MC}_t^{own} = \overline{K}_t^{own} + \vartheta_t \cdot P_t^{d*} \tag{18}$$

where:

$\overline{MC}_t^{own}$ average marginal cost of own electricity generation in year t (HTG/kWh)

$\overline{K}_t^{own}$ average cost of capital cost for own electricity generation in year t (HTG/kWh)

ϑ_t average variable fuel consumption of small diesel generator for self-electricity generation oil plants in year t (liter/kWh) [116]

P_t^{d*} average diesel fuel cost for own electricity generation in year t (HTG/kWh)

Hence,

$$\overline{MC}_t^{own} = 15.61\ HTG/kWh \tag{19}$$

At the current exchange rate (HTG/US$ = 55), the marginal cost of own-generation in US$ is about 28.4 US cents per kWh. The capital cost component of self-generation is approximately 0.02 US$/kWh. For this analysis, capital costs for self-generation is assumed to remain constant.

[115] Calculations in column M are at 12% discount rate.

[116] This is weighted-average fuel consumption of small generator, liter per kWh. The estimates are sensitive to the followings: 1) the share of ownership for each size of generator (column B), 2) generator size and fuel type (column C, D), 3) the lifetime of generators (column F), and 4) the load factor of each type of generator ownership (column G).

Table H4. Sensitivity Tests on International Crude Oil Prices

*Local Retail Price (HTG/liter)**	*Crude Oil Price, International ($/bbl)*	*Marginal Cost of Own-Generation (HTG/kWh)*	*Average Max WTP (HTG/kWh)*
HTG 12.19	USS 35	HTG 11.4	HTG 12.5
HTG 13.93	USS 40	HTG 12.9	HTG 14.0
HTG 15.67	USS 45	HTG 14.3	HTG 15.4
HTG 17.41	**USS 50**	**HTG 15.8**	**HTG 16.9**
HTG 19.16	USS 55	HTG 17.3	HTG 18.4
HTG 20.90	USS 60	HTG 18.7	HTG 19.8
HTG 22.64	USS 65	HTG 20.2	HTG 21.3

Note that the fuel cost dominates own cost of electricity generation; therefore, fuel prices for own electricity generation and efficiency of small generators are key variables determining the value own cost of electricity generation. Average fuel consumption of small generators, ϑ_t, owned by connected consumers is assumed to be declining at a rate of 0.5 % per year[117].

$$\overline{WTP}_t^{max} = 2 * \overbrace{K_t^{own} + \vartheta_t \cdot P_t^{d*}}^{\overline{MC}_t^{own}} + r^* \tag{20}$$

where:

$\overline{WTP}_t^{max}$ average marginal cost of own electricity generation in year t (HTG/kWh)

r^* additional reliability premium associated with the power supply (HTG/kWh), can be attributed to the loss of a comfort, loss of profits due to outages, etc.

117 Therefore, it is assumed to be declining at a slower rate than the utility generation, which is 0.75%/year. The assumption can be justified with the size of utility level generators and fuel consumption.

Table H5. Marginal Cost of Self - Electricity Generation – Private Consumers[118]

MARGINAL COST OF SELF-ELECTRICITY GENERATION (Nominal)		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Fuel Prices for Private (own) Electricity Generation															
Wholesale Diesel Oil Price at Domestic Market - before taxes	HTG/liter	24.90	27.39	30.13	33.14	36.46	40.11	...	104.02	...	269.81	...	699.81	...	1,650.12
Import Duty on Petroleum Imports	HTG/liter							...		...		...		...	
Average Excise Tax on Fuel Purchases	HTG/liter	1.49	1.64	1.81	1.99	2.19	2.41	...	6.24	...	16.19	...	41.99	...	99.01
Other Gov't Charges, on wholesale price	HTG/liter	9.96	10.96	12.05	13.26	14.58	16.04	...	41.61	...	107.92	...	279.92	...	660.05
Taxes on Fuel for Own Generation	HTG/liter	11.45	12.60	13.86	15.25	16.77	18.45	...	47.85	...	124.11	...	321.91	...	759.05
Gas Oil Price for Own Generation (including taxes and other charges)	HTG/liter	36.36	39.99	43.99	48.39	53.23	58.55	...	151.87	...	393.92	...	1,021.72	...	2,409.17
FEP on Fuel Payments	HTG/liter	1.43	1.58	1.73	1.91	2.10	2.31	...	5.98	...	15.51	...	40.24	...	94.88
Economic Cost of Gasoil for Self-Generation	HTG/liter	26.33	28.97	31.86	35.05	38.56	42.41	...	110.00	...	285.32	...	740.05	...	1,745.00
A. Marginal Fuel Cost of Own Electricity Generation (Econ Value of Reduced Peak Self Generaiton)															
Gas Oil Price for Own Generation (including taxes and other charges)	HTG/liter	36.36	39.99	43.99	48.39	53.23	58.55	...	151.87	...	393.92	...	1,021.72	...	2,409.17
Average fuel consumption of small diesel generator	liter/kWh	0.40	0.40	0.40	0.40	0.40	0.39	...	0.37	...	0.36	...	0.34	...	0.32
Marginal Fuel Cost of Own-Generation (inc. of tax and other gov't charges)	HTG/kWh	14.69	16.08	17.60	19.26	21.08	23.07	...	56.91	...	140.40	...	346.36	...	780.67
B. Capital Costs for Self-Generation (Generator Cost)															
Foreign Price Index (US)	#	1.00	1.03	1.06	1.09	1.13	1.16	...	1.56	...	2.09	...	2.81	...	3.67
Expected Nominal Exchange Rate (HTG/US$)	#	55.00	58.74	62.73	66.99	71.55	76.41	...	147.47	...	284.61	...	549.29	...	992.67
Average Capital Cost for Self-Generation (i.e.small generator)	US$/kWh	0.02	0.02	0.02	0.02	0.02	0.02	...	0.02	...	0.02	...	0.02	...	0.02
Capital Cost for own-generation	HTG/kWh	1.10	1.21	1.33	1.46	1.61	1.77	...	4.59	...	11.92	...	30.91	...	72.89
Marginal PRIVATE Cost of Electricity Generation (A+B)															
Marginal Cost of Self-Generation	HTG/kWh	15.79	17.29	18.93	20.72	22.69	24.84	...	61.51	...	152.32	...	377.27	...	853.56
Marginal Economic Fuel and Capital Cost of Self-Generation	HTG/kWh	11.74	12.85	14.08	15.41	16.88	18.48	...	45.82	...	113.61	...	281.78	...	638.34
Tax Distortions (=Undistorted Economic MC - Distorted Private MC)	HTG/kWh	4.05	4.43	4.85	5.31	5.81	6.36	...	15.69	...	38.71	...	95.49	...	215.22

ECONOMIC VALUE OF REDUCED PEAK LOAD SELF- GENERATION (Real)		2015	2016	2017	2018	2019	2020	...	2030	...	2040	...	2050	...	2059
Domestic Price Index	#	1.00	1.10	1.21	1.33	1.46	1.61	...	4.18	...	10.83	...	28.10	...	66.26
Million to Thousand Conversion 1,000,000	#														
Net Incremental Peak Energy Transmitted from 70 MW Hydro Capacity	kWh	0	0	0	0	8,462,598	11,396,170	...	13,651,572	...	15,906,974	...	18,162,376	...	0
Marginal Cost of Self-Generation	HTG/kWh	15.79	17.29	18.93	20.72	22.69	24.84	...	61.51	...	152.32	...	377.27	...	853.56
Value of Reduced Peak-Load Self Generation Costs (i.e. private consumers)	HTG					131,142,535	175,782,942	...	201,011,264	...	223,625,156	...	243,825,886	...	
Value of Reduced Peak-Load Self Generation Costs (i.e. private consumers)	Million HTG					131.14	175.78	...	201.01	...	223.63	...	243.83	...	
Tax Distortions (=Undistorted Economic MC - Distorted Private MC)	HTG/kWh	4.05	4.43	4.85	5.31	5.81	6.36	...	15.69	...	38.71	...	95.49	...	215.22
Value of Reduced Taxes from Reduced Self-Generation	HTG	0	0	0	0	33,587,709	45,004,781	...	51,275,891	...	56,826,242	...	61,711,320	...	0
Value of Reduced Taxes from Reduced Self-Generation	Million HTG	0.0	0.0	0.0	0.0	33.6	45.0	...	51.3	...	56.8	...	61.7	...	0.0

118 Domestic fuel cost for self-electricity generation is initially estimated from world price of crude oil, and its price is expressed in US$. The annual nominal prices of fuels are converted into their HTG values through adjustment with the annual price index of the US and nominal exchange rate in the same year.

Annex I.Valuation of Economic Benefits

1. Economic Value of Production Cost Savings During Off-Peak Load Hours

The production cost savings are generated from incremental transmission from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity

Recall equation 13, Annex F.

$$FV_t^f = F_{lt}^f \cdot P_t^f \qquad \forall_{t,l=1}$$

<u>*Economic Value of Fuel Savings*</u>

$$\boldsymbol{EV_t^f = FV_t^f \cdot CvF^f} \qquad \forall_{t,l=1} \qquad \textbf{(21)}$$

where:

EV_t^f	economic value of fuel savings in year t (HTG)
FV_t^f	financial value of fuel savings in year t (HTG)
CvF^f	the conversion factor of heavy fuel oil

<u>*Economic Value of O&M Cost Savings*</u>

Recall equation 14, Annex F; financial Value of O&M Cost Savings

$$FV_t^m = M_{zt} \cdot -\Delta q_{zlt} \qquad \forall_{t,l=1}$$

Using CSCF for O&M cost savings, we get the economic value of such savings from the following calculation:

$$\boldsymbol{EV_t^m = FV_t^m \cdot CvF^m} \qquad \forall_{t,l=1} \qquad \textbf{(22)}$$

where:

FV_t^m	financial value of O&M cost savings in year t (HTG)
EV_t^m	economic value of O&M cost savings in year t (HTG)
CvF^m	the conversion factor of O&M costs

Therefore, the total economic value of the total production cost savings are:

$$\boldsymbol{EV\ of\ Production\ Cost\ Savings\ (HTG) = EV_t^f + EV_t^m} \qquad \forall_{t,l=1}$$

2. Economic Value of Incremental Peak-Load Sales Revenue

The incremental peak load sales, valued at marginal cost of self-electricity generation, are generated from incremental transmission from 50 MW Existing Peaking and 20 MW Planned Baseload Hydro Capacity.

<u>During peak load hours; l = 2; *peak load*</u>

$$\Delta \boldsymbol{T}_{\boldsymbol{elt}} = +\Delta \boldsymbol{D}_{\boldsymbol{lt}} = -\Delta \boldsymbol{q}_{\boldsymbol{lt}}^{\boldsymbol{OWN}} \qquad \forall_{\boldsymbol{t,l=2}} \tag{23}$$

where

$-\Delta q_{lt}^{own}$ the amount of energy reduced from self-electricity generation, equal to amounts of peak-load energy delivered by the utility (negative sign indicates displacement or say reduction of self-electricity generation during peak-load hours)

Therefore,

$$\boldsymbol{EV}_{\boldsymbol{t}}^{\boldsymbol{s}} = \Delta \boldsymbol{D}_{\boldsymbol{lt}} \cdot \overline{\boldsymbol{MC}}_{\boldsymbol{t}}^{\boldsymbol{own}} \qquad \forall_{\boldsymbol{t,l=2}} \tag{24}$$

where:

EV_t^s economic value of additional peak sales in year t (HTG)

$\overline{MC}_t^{own}$ marginal cost of self-electricity generation (HTG/kWh)[119]

3. Economic Value of Transmission Line from Additional 10 MW Generation Capacity

Recall equation 17, Annex F; financial Value of Transmission Cost avoided:

$$FV_t^p = q'_{pt} \cdot \gamma_t \qquad \forall_t$$

The economic value of transmission costs avoided is therefore:

$$\boldsymbol{EV}_{\boldsymbol{t}}^{\boldsymbol{p}} = \boldsymbol{FV}_{\boldsymbol{t}}^{\boldsymbol{p}} \cdot \boldsymbol{CvF}^{\boldsymbol{p}} \qquad \forall_{\boldsymbol{tl}} \tag{25}$$

where:

EV_t^p economic value of additional power from enhanced transmission capacity (HTG)

CvF^p conversion factor estimated for transmission costs avoided for generation expansion.

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[119] See Annex H.

4. Economic Value of Emission Reductions

<u>Emission Savings from reduced utility electricity generation</u>

Recall equation (12), presented in Annex F.

$F_t^f = \beta_{zt}^f \cdot \Delta q_{zlt}$

where:

F_t^f the total amount of fuel displaced from least-fuel efficient plant during off-peak load hours (liters), estimated from

β_{zt}^f the fuel consumption of the least-fuel efficient plant during off-peak load hours (liters/kWh), assumed to be always heavy fuel oil 'f' during the lifetime of the project.

Δq_{zlt} the amount of energy displaced from least-fuel efficient plant during off-peak load hours (kWh)

<u>Emission Savings from reduced peak-load self-generation</u>

Recall, fuel consumption of self-generator (Annex H, equation 18)

ϑ_t average variable fuel consumption of small diesel generator for self-electricity generation oil plants in year t (liter/kWh)

Recall statement 23, Annex I.

$$\Delta \boldsymbol{T}_{\boldsymbol{elt}} = +\Delta \boldsymbol{D}_{\boldsymbol{lt}} = -\Delta \boldsymbol{q}_{\boldsymbol{lt}}^{\boldsymbol{OWN}} \qquad \forall_{t,l=2}$$

where

$-\Delta q_{lt}^{own}$ the amount of kWh energy reduced from self-electricity generation, equal to amounts of peak-load energy delivered by the utility (negative sign indicates displacement or say the reduction of self-electricity generation during peak-load hours).

Therefore, <u>liters of diesel fuel</u> saved from self-electricity generation is:

$$F_t^{d*} = q_{lt}^{own} \cdot \vartheta_t \qquad \forall_{t,l=2} \qquad (26)$$

where

F_t^{d*} liters of diesel fuel saved from reduced self-generation during peak load hours, every year[120]

Therefore, tonnes of carbon emission saved from utility electricity generation is:

$$E_t = \frac{F_t^t \cdot CO_2^f}{1000} + \frac{F_t^{d*} \cdot CO_2^d}{1000} \quad (27)$$

where

E_t the carbon emissions reduced in year t (metric ton)

CO_2^f the carbon intensity of heavy fuel oil (kg/liter)

CO_2^d the carbon content of diesel fuel (kg/liter)

Therefore, the economic value of tonnes of carbon emission saved from utility electricity generation is:

$$EVE_t = \epsilon_H.(E_t \cdot P_t^c) \quad (28)$$

EVE_t the economic value of carbon emissions reduced in year t, HTG

ϵ_H emission benefits to locals (%)

P_t^c social cost of carbon (HTG/ton)

Annex J.Derivation of Impacts on Externalities

The relationship between financial and economic analysis of the appraisal:

$$PV^{EOCK} \sum_i E_i = NPV_e^{EOCK} - NPV_f^{EOCK}$$

Following, CSCF estimates, presented in Table 13, there exist external benefits and/or costs for each project item as long as CSCF (or CvF) is different than 1. If the conversion factor for benefit item is greater than 1, the economic value of that item is larger than it is to electric utility (so NPV economy improves), vice -versa. If the conversion factor for cost item is greater than 1, the economic cost of the item is larger than its financial cost (so NPV economy decreases), vice-versa.

120 Note that there will no reduction in emissions from utility peak-load supply. The reason is that utility will not save fuel during peak-load hours. And even hydro-generation emits pollution, such emissions cannot be deducted because emissions are released at the generation level, not the transmission level.

1. Derivation of Externalities from Production Cost Savings

Fuel Savings

$$CvF^f < 1 \xrightarrow{yields} EV_t^f < FV_t^f = Gov'Tax\ Losses\ (-) \quad (29)$$

O&M Cost Savings

$$CvF^m < 1 \xrightarrow{yields} EV_t^m < FV_t^m = Gov'Tax\ Losses\ (-) \quad (30)$$

2. Peak-Load Utility Sales = Reduced Peak-Load Self-Generation

The marginal cost of own generation is more expensive than utility cost of electricity generation (so retail price). This is due to the higher price of diesel oil for the own cost of electricity generation, and ownership of less fuel-efficient generators used for own generation, as outlined in Appendix E and H.

$$\overline{MC}_t^{own} > \bar{P}_t^r \xrightarrow{yields} EV_t^s > FV_t^s = Consumer\ Surplus\ (+) \quad (31)$$

Both $\overline{MC}_t^{own}$ and $\bar{P}_t^r$ are tax inclusive. Therefore, they are distorted prices. The tax impacts of the gov't can be computed from the difference between their undistorted price and distorted price. The electric utility will sell more of peak-load electricity. Therefore, the gov't will generate extra tax revenue. The consumers will reduce their fuel purchases as they will shift their consumption from own generation sources to utility supplied energy. Therefore, the gov't will lose tax collections from them.

$$\overline{MC}_t^{own} > Undistorted\ marginal\ cost \xrightarrow{yields} Gov't\ Tax\ Loss(-) \quad (32)$$

$$\bar{P}_t^r > Undistorted\ price \xrightarrow{yields} Gov't\ Tax\ Gain\ (+) \quad (33)$$

3. Transmission Costs Avoided (see Table 13, p. 41)

$$CvF^p > 1 \xrightarrow{yields} EV_t^p > FV_t^m = Gov'Tax\ Gain\ (+) \quad (34)$$

4. Grants (see Table 12, page 40).

$$CvF^g = 0 \xrightarrow{yields} Other\ Projects\ (-) \quad (35)$$

5. Emission Reduction Benefits (see Table 12).

$EVE_t > 1 \xrightarrow{yields} Benefit\ to\ Locals\ (added\ as\ part\ of\ benefits\ to\ electricity\ consumers)$
(36)[121]

[121] Environmental benefits are for <u>all</u> locals because emission benefits are non-excludable and non-rival in nature. However, for simplicity, they are included as part of consumer benefits. These benefits are very little in comparison to bill savings consumers would acquire.

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