CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Title of the project activity: “Refurbishment of Enguri Hydro Power Plant, Georgia”
Version 7 of the document
Version Date: 31/01/2012

A.2. Description of the project activity:

(1) Purpose of the project activity:

The purpose of this Clean Development Mechanism (CDM) project is to increase the operating capacity of the Enguri Hydro Power Plant (HPP) by a total of 210 MW[1] by undertaking rehabilitation of the four units.

(a) The scenario existing prior to the start of the implementation of the project activity:

The Enguri Hydro Power Project has 5 units, each with nameplate capacity of 260MW. Thus, the initial design capacity of the entire plant was 1300 MW. Since the original commissioning of Enguri HPP (1978-1980), four generating units (out of five) have been operating at relatively low capacity (210-230 MW) and in a regime of frequent emergency shut-downs. The maximum generation capacity of each of the units prior to rehabilitation is[2]:

- Unit # 1: 210MW
- Unit # 2: 220MW
- Unit # 4: 210MW
- Unit # 5: 230MW

The fifth unit (Unit #3) was completely shutdown in 1993 due to damage to the mechanical parts and faulty initial design.

(b) The project scenario, including a summary of the scope of activities/measures that are being implemented within the proposed project activity:

- The CDM project activity includes the full-scale rehabilitation of four units of the Enguri HPP (Unit #1, #2, #4, #5).
- The rehabilitation of Unit # 3 of Enguri HPP is out of the scope of this CDM project activity. So, Unit # 3 is **not** part of the CDM project activity.

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[1] After the retrofit, the operating capacity of each unit will be increased to 270MW, i.e. Unit 1 and Unit 4 will increase capacity by 60MW from the prior-to-rehabilitation operating capacity of 210MW, Unit 2 – by 50MW from the prior-to-rehabilitation operating capacity of 220MW, and Unit 5 – by 40MW from the prior-to-rehabilitation operating capacity of 230MW. The sum of individual increases (60MW, 50MW, and 40MW accordingly) equals 210MW.

[2] Letter of Director of Engurhesi CAP(BL) June 2005.pdf

The baseline scenario, as identified in section B.4

The baseline scenario is the same as the scenario existing prior to the start of implementation of the project activity.

(2) Explain how the proposed project activity reduces greenhouse gas emissions

The proposed CDM project activity will increase the overall output from the Enguri HPP, thereby allowing Enguri HPP to produce more electricity without the need to construct an additional power plant. The CDM project will reduce the need to use electricity based on fossil fuel combustion. The overall reduction of GHG during the crediting period is estimated at an average of **730,478** tonnes of CO_2 equivalent (CO_{2eq}) per year or **7,304,785 tonnes of CO_{2eq}** over a ten year crediting period (1 October 2011 to 30 September 2021), by offsetting more carbon-intensive electricity production from the Georgian electric grid.

(3) The view of the project participants on contribution of the project activity to sustainable development:
According to the project participants, this project contributes to sustainable development in Georgia. Specifically, the project contributes, as follows, to the three aspects of sustainable development:

<u>*Economic aspects*</u>

- *Sustainable technology transfer*: Internationally renowned engineering firms (Voith Siemens, Stucky, Electrowatt-Econo and Electricite de France) are involved in this project and modern technology is transferred to Georgia.
- *Effect on the region*: The project is implemented in the Gali region, which is a relatively rural and economically disadvantaged region of Georgia.
- *Employment generation*: New employment is created during construction works at Enguri HPP.

<u>*Environmental aspects*</u>

- *Substitution of fossil fuels*: The project will substitute the power plants on the margin of the electricity system in Georgia. These are hydro power plants and thermal power plants running on natural gas. The project can reduce over 730,478 tCO_2 per year on average. In addition, the project will reduce local pollutant emissions (NO_x, SO_2, VOCs) associated with electricity generation in Georgia, with positive health impacts for the local population
- *Water quality*: The existing water reservoir will not be increased. Water resources will be used more efficiently.

<u>*Social aspects*</u>

- *Stakeholders contributions:* A stakeholder consultation was organised specifically for this project in Tbilisi on 12 March 2007. All comments received for the project were positive and favourable.
- *Availability of better living conditions*: The project contributes to increased safety of the region surrounding the dam structure. As mentioned above, the project generally contributes to increased energy security in the country.
- *Development of intellectual capacity*: The introduction of updated technology and training of local employees will contribute to increased Georgian intellectual capacity

A.3. Project participants:

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Georgia (host)	Engurhesi Ltd.	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

Enguri Hydro Power Plant is located in the Gali Region of Abkhazia, near to the north-east coast of the Black Sea.

A.4.1.1. Host Party(ies):

Georgia

A.4.1.2. Region/State/Province etc.:

Gali Region of Abkhazia

A.4.1.3. City/Town/Community etc:

The water reservoir of Enguri HPP is located deep in the gorge, along the flow of the river Enguri, at a distance of 5 km from the settlement of Jvari. The power house is situated 15 km from the dam, on territory of the village of Saberio. The CDM project will take place at the power house, near the town of Saberio.

A.4.1.4. Detail of physical location, including information allowing the unique identification of this project activity (maximum one page):

Latitude: 42° 45’ 32.50’’ N
Longitude: 42° 01’ 53.51’’ E
Elevation: 256 m

Figure 1 The CDM project's location

A.4.2. Category(ies) of project activity:

This CDM project corresponds to a project category of the Sectoral Scope Number 1: Energy Industries (renewable -/ non-renewable sources).

A.4.3. Technology to be employed by the project activity:

How environmental safe and sound the technology is?
The proposed project activity is a rehabilitation project. By rehabilitation, the overall output from each of the units of Enguri HPP has been increased. The project activity does not lead to any increase in the overall reservoir capacity. Thus, this is an environmentally safe and sound technology.

(a) The scenario existing prior to the start of the implementation of the project activity, with a list of the equipment(s) and systems in operation at that time:

Prior to the rehabilitation of the Enguri HPP, the units were running at much lower capacity than the maximum original nameplate output capacity. Since, the units were operating at lower capacity; the deficit of power supply was met by power plants connected to the Georgian Grid.

The system - that was in operation prior to the start of the project activity - composed of the generators, turbine for each of the units, including voltage regulators and excitation systems, low voltage equipment and accessories, unit control/ protection/ monitoring systems, speed governors, spherical valve operating

mechanisms. The auxiliaries included common AC/DC auxiliaries, transformers, drainage system and compressed air system.

The age of four units expressed in number of operation hours is given below:

Unit #	Operating age at the end of 2005 (in hours)
Unit 1	97,266
Unit 2	108,619
Unit 4	111,251
Unit 5	131,221

The average remaining lifetime of the equipments was estimated per the methodological guidelines, including step by step procedure for calculating $DATE_{BaselineRetrofit}$. It is calculated in detail in section B.4 of this PDD. The calculation results are summarised below:

	At the end of 2005	Lifetime before rehabilitation	Remaining Lifetime of Units (Hours) at end of 2006	Expected lifetime years	$DATE_{Baseline\,\mathrm{Re}trofi}$
Unit 1	97,266	220,150	122,881	24.6	2029.6
Unit 2	108,619	220,150	111,531	22.3	2028.3
Unit 4	111,251	220,150	108,899	21.8	2027.8
Unit 5	131,221	220,150	88,929	17.8	2022.8

To be conservative $DATE_{BaselineRetrofit}$ has been taken as 2022 (31/12/2022) for all the four units.

In the baseline, the turbines and generators of the Enguri HPP units would have continued to use the potential energy of water to convert it into electricity, **albeit at lower efficiency and capacity**. Thus, the excess power (produced by the units after rehabilitation) would have been produced by fossil fuel fired power plants in the grid leading to higher CO_2 emissions. The rehabilitation work will replace equivalent power from the grid (with a grid emission coefficient of 0.3999tCO_{2eq}).

(b) The scope of activities/measures that are being implemented within the project activity, with a list of the equipment(s) and systems that will be installed and/or modified within the project activity;

Rehabilitation of the four Units (Unit # 1, 2, 4 and 5):

1. Replacement of stator water cooled winding and, stator bars cooling system
2. Rehabilitation of vibration monitoring system and generator fire-extinguishing system
3. Rehabilitation of rotor poles with reinsulated field coils
4. Replacement of stator magnetic core and eight air coolers
5. Supply of low voltage equipment and accessories
6. Supply of unit control/ protection/ monitoring system
7. Rehabilitation of spped governor and spherical valve operating mechanism

Rehabilitation of the Auxiliaries:

1. Rehabilitation of electrical AC and DC auxiliaries
2. Rehabilitation of drainage system

3. Rehabilitation of compressed air supply system

The rehabilitation of the four units allows the increase of capacity by 40-60 MW (different for each of the units). By increasing the capacity of the units, Enguri HPP will be able to produce more electricity for the Georgian grid, simultaneously offsetting more carbon-intensive electricity generation elsewhere in Georgia.

It is expected that no other more efficient technologies or additional rehabilitative works (such as for example, the substitution of turbines and generators with new devices) will be carried out during the chosen crediting period of ten years.

The planning and implementation status of the proposed project activity is presented below:

- **Unit#2.** The rehabilitation work was started in January 2006 and was expected to be concluded in 13 months, i.e. by February 2007. However, the rehabilitation work was completed in March 2008.
- **Unit#4.** The rehabilitation works began in January 2008 and was completed in August 2009.
- **Unit#1.** The rehabilitation works were expected to begin in July 2010 and be completed by March 2012.
- **Unit#5.** The rehabilitation works were expected to begin after rehabilitation work of Unit # 1 is completed. The rehabilitation work is expected to start in April 2012 and expected to be completed by March 2013.

Note: The initial rehabilitation plan envisaged the complete refurbishment of Unit 3 (not part of the CDM project scope) followed by works on Unit 2 and Unit 1. The 2001 EBRD loan ended up covering only the completion of works on Unit 3. Facing financial difficulties, Engurhesi was not able to carry on with the rehabilitation programme. Using CDM as an additional guarantee, Engurhesi managed to secure additional funding to cover the rehabilitation works on Units 2 and 1, and undertake the refurbishment of Unit 4 and 5.
However, due to technical reasons, Unit 1 was later replaced by Unit 4 in the schedule via amendment agreement signed with the contractor in 2007. The Amendment states: "*during the execution of rehabilitation works the Employer requested the contractor, due to unforeseen design deviations (turbine head cover) within Employers scope of supply and works, to rehabilitate Unit #4 instead of Unit #1*".

The contractor Voith Siemens has been awarded the contract for complete rehabilitation work. The rehabilitation work by Voith Siemens helps the units of Enguri HPP to be able to produce power at a higher capacity than what they were able to produce during the baseline scenario (prior to rehabilitation work).

(c) The baseline scenario, as identified in Section B.4: With an indicative list of the equipment(s) and systems that would have been in place in the absence of the project activity:

The baseline scenario is the same as the scenario existing prior to the rehabilitation activities being undertaken as part of this project activity. This has been indicated already under (a) above.

(d) The source of GHG emissions in the baseline scenario that will be reduced as part of the project activity:

The baseline for the CDM project activity is grid connected power plants, represented by 'the combined margin' emission factor for the grid. Only the CO_2 emissions due to combustion of fossil fuels at the grid-connected power plant have been considered to contribute to the baseline emissions.

A.4.4 Estimated amount of emission reductions over the chosen crediting period:

Total average annual emission reductions from the electricity generated by the project are estimated as **730,478** tonnes of CO_2 equivalent (CO_{2eq}) per year or **7,304,785 tonnes of CO_{2eq}** over a ten year crediting period from 1 October 2011 to 30 September 2021.

Years	Annual Estimation of Emission Reductions in tonnes of CO_{2eq}
2011	102,457
2012	549,220
2013	722,820
2014	765,198
2015	765,198
2016	765,198
2017	765,198
2018	765,198
2019	765,198
2020	765,198
2021	573,899
Total estimated reductions (tonnes of CO_{2eq})	**7,304,785**
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_{2eq})	**730,478**

A.4.5. Public funding of the project activity:

The European Bank for Reconstruction and Development (EBRD) is providing a loan to Engurhesi Ltd. for the rehabilitation works at the Enguri HPP. The EBRD funding does not result in a diversion of official development assistance.

In addition, the European Commission provides a grant to Engurhesi Ltd. for the rehabilitation works at the Enguri HPP. The European Commission states that this grant does not constitute diversion of official development assistance funds.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

Version 12.1.0 of ACM0002 Consolidated baseline methodology for grid-connected electricity generation from renewable sources (EB52)
Version 03.0.0 of the Combined Tool to identify the baseline scenario and demonstrate additionality (EB60)
Version 05.2 of the Tool for the demonstration and assessment of additionality (EB39)
Version 02.2.0 of the Tool to calculate the emission factor of an electricity system (EB61)

B.2 Justification of the choice of the methodology and why it is applicable to the project activity:

ACM0002 (Version 12.1.0) is applicable to grid-connected renewable power generation project activities under the following conditions:

- *This methodology is applicable to grid-connected renewable power generation project activities that (a) install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) involve a capacity addition; (c) involve a retrofit of (an) existing plant(s); or (d) involve a replacement of (an) existing plant(s)*

The refurbishment of Enguri hydro power plant is a renewable power generation project activity connected to the Georgian power grid. The project activity belongs to type (c), i.e. it involves a retrofit of the existing plant.

- *The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit;*

The refurbishment of Enguri hydro power plant is retrofit of hydro power plant with an accumulation reservoir.

- *In the case of capacity additions, retrofits or replacements (except for wind, solar, wave or tidal power capacity addition projects which use Option 2: on page 11 to calculate the parameter $EG_{PJ,y}$): the existing plant started commercial operation prior to the start of a minimum historical reference period of five years, used for the calculation of baseline emissions and defined in the baseline emission section, and no capacity expansion or retrofit of the plant has been undertaken between the start of this minimum historical reference period and the implementation of the project activity*

The refurbishment of Enguri hydro power plant is at the units that have been in operation since 1978-1980. No capacity expansion or retrofit of the plant has been undertaken between the start of the historical reference period and the implementation of the project activity. Thus, there is availability of 26-28 years of historical performance information for each of the units of Enguri hydro power plant.

- *In case of hydro power plants, one of the following conditions must apply:*
    - *The project activity is implemented in an existing reservoir, with no change in the volume of reservoir; or*
    - *The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2; or*
    - *The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m2.*

The project includes an existing reservoir whose volume will not be increased during or after the project implementation. This information is stated in the "*Enguri Dam and Hydroelectric Power station, Georgia. Feasibility study for rehabilitation. Part 1. Technical and economic studies*". Thus, the condition no.1 is applicable in the case of Enguri project activity, i.e. the project activity is implemented in an existing reservoir, with no change in the volume of reservoir.

- *This methodology is not applicable to project activities that involve switching from fossil fuels to renewable energy at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site;*

The refurbishment of Enguri hydro power plant does not involve switching from fossil fuels to renewable energy at the site.

- *Biomass fired power plants;*

The refurbishment of Enguri hydro power plant does not involve biomass fired power plants.

- *Hydro power plants that result in new reservoirs or in the increase in existing reservoirs where the power density of the power plant is less than 4 W/m^2.*

The refurbishment of Enguri hydro power plant does not involve any increase in existing reservoir

- *The geographic and system boundaries for the relevant electricity grid can be clearly identified and information on the characteristics of the grid is available;*

The boundaries for the Georgian grid system are clearly identified and information of the characteristics of the Georgian grid is available and presented in the following sections.

As required by the methodology it is demonstrated later in the section that the most plausible baseline for the project activity is "continuation of current situation, i.e. to use of the power generation equipment that was already in use prior to the implementation of project activity and undertaking business as usual maintenance"

Additionally, the project meets the following conditions/definitions as indicated in the latest version of the methodology ACM0002 (version 12.1.0):

1. Definition of Retrofit (or Rehabilitation or Refurbishment): A retrofit is an investment to repair or modify an existing power plant/unit, with the purpose to increase the efficiency, performance or power

generation capacity of the plant, without adding new power plants or units, or to resume the operation of closed (mothballed) power plants. A retrofit restores the installed power generation capacity to or above its original level. Retrofits shall only include measures that involve capital investments and not regular maintenance or housekeeping measures.

Outcome: The Enguri rehabilitation project meets this applicability condition/definition. Investments are made only to repair existing power plant unit with the purpose of increasing the efficiency, performance and power generation capacity of the plant. No new power plant or units are added. Due to retrofit the power generation capacity is increase to slightly above the original name plate capacity of 260MW, by 10MW to a new capacity of 270MW.

2. Definition of Existing reservoir. A reservoir is to be considered as an "existing reservoir" if it has been in operation for at least three years before the implementation of the project activity.

Outcome: The reservoir has been in existence for over 25 years prior to start of the rehabilitation activity, and hence would qualify as an 'existing reservoir'.

Since, the CDM Enguri project meets all the applicability conditions as required by the methodology, the use of ACM0002 (Version 12.1.0) is justified.

B.3. Description of the sources and gases included in the project boundary

Emission sources
As per the ACM0002 methodology *"For the baseline determination, project participants shall only account CO_2 emissions from electricity generation in fossil fuel fired power that is displaced due to the project activity."* The spatial extent of the project boundary includes the project site that is actually rehabilitated (which corresponds to Units #2, #4, #1 and #5 of the Enguri HPP) and all the plants connected physically to the electricity system that the CDM project power plant is connected to.
Under the project scenario there are no sources of CO_2, CH_4 and N_2O from within the project boundary. In fact, the Enguri rehabilitation project is not a new hydroelectric project with reservoirs, and thus the project boundary does not need to include the reservoir area.

	Source	Gas	Included?	Justification/explanation
Baseline	No sources	CO_2	Yes	Main source of emissions from combustion of fossil fuels at grid-connected power plants, which is represented by the 'combined margin' of the grid.
		CH_4	No	For simplification
		N_20	No	For simplification
Project Activity	No sources	CO_2	No	No emissions
		CH_4	No	No emissions
		N_20	No	No emissions

In addition, as per ACM0002, no CO_2 emissions from transportation or project construction are to be accounted and therefore, no leakage is accounted for in this project activity. Also since the reservoir is not modified by the proposed project activity, no sources of methane (from decay of flora/fauna in the reservoir) are accounted for in this project activity.

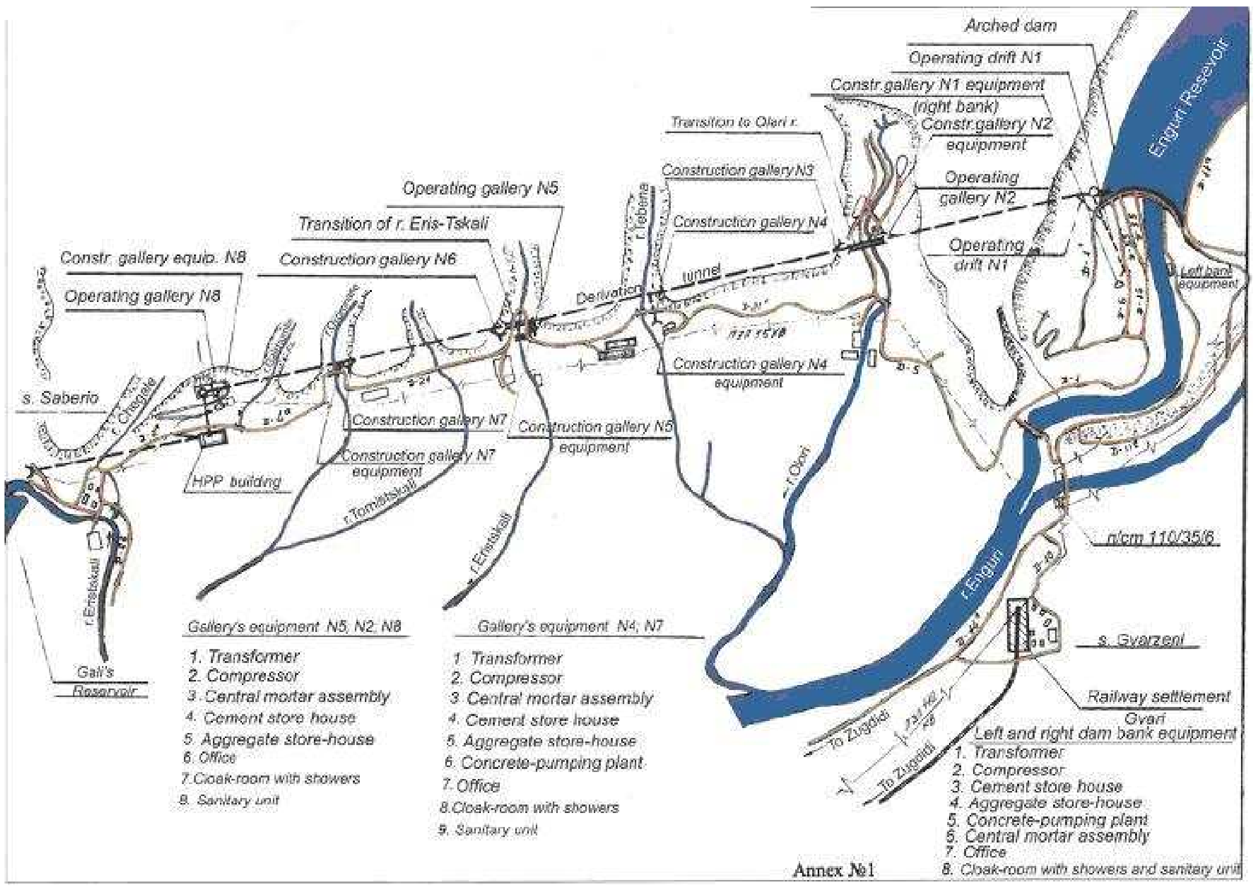
Spatial extent of the project boundary

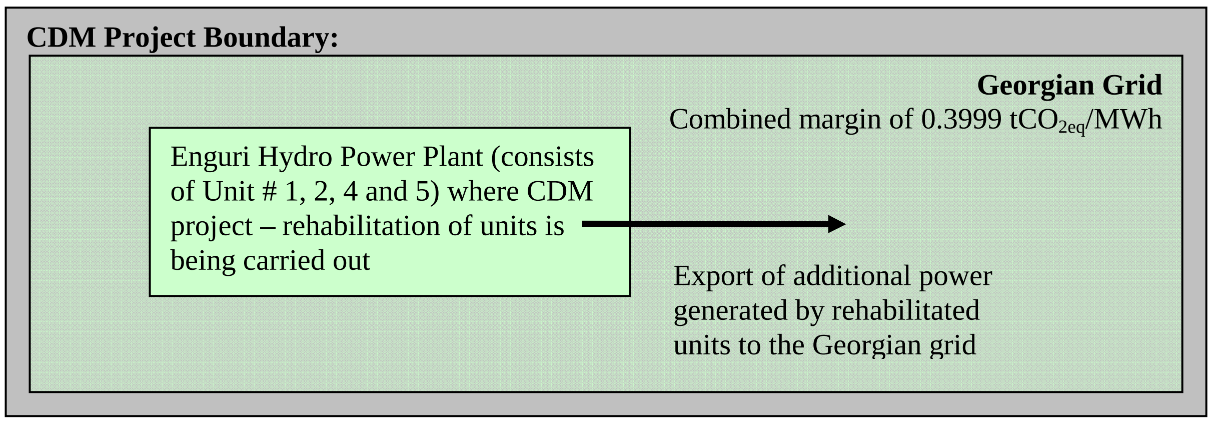
As per the ACM0002 methodology *"The **spatial** extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the CDM project power plant is connected to.*
*For the purpose of determining the build margin (BM) and operating margin (OM) emission factor, as described below, a (regional) **project electricity system** is defined by the spatial extent of the power plants that can be dispatched without significant transmission constraints"*.

As per the Georgian DNA, the whole Georgian electricity grid has been considered to calculate the emission factor for Georgia. Hence, in this PDD, the Georgian electricity grid is defined as the project electricity system.

In addition, the imports of electricity from Russia and Armenia were included in the spatial extent of the project boundary for the purposes of calculation of the operating margin (OM), as requested by the ACM0002 methodology.

The schematic representation of the area around Enguri HPP is shown below.





B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

Key assumptions have been made in the CDM PDD:

1. Step 1 – Two alternatives have been identified (P1 and P2) and option P3 has been eliminated
2. Calculation of $DATE_{BaselineRetrofit}$
3. Step 2 – Barrier Analysis (Identification of appropriate barriers, as relevant)
4. Barrier 1 – Investment barrier (Lack of Private Capital)
5. Barrier 2 – Risks due to low collection ratios
6. Barrier 3 – Risks due to devaluation of $ vis-à-vis €
7. Barrier 4 – Risks due to low tariff levels

A brief justification for each of the above assumptions (respectively matched with the assumption number) is given below. A detailed description follows later in this section.

1. Option P3 concerns partial rehabilitation, which is not possible in this case, as the generation facility is a series of equipments and each one of these equipments in the series needs to be rehabilitated to achieve the required efficient gains.
2. $DATE_{BaselineRetrofit}$ has been calculated as per the guidelines provided in the latest version of the methodology ACM0002, considering the rehabilitation activities undertaken in hydro plants in Georgia.
3. Four barriers have been selected. These barriers affect the implementation of the project activity and lead to maximum uncertainty w.r.t. the developer's ability to complete the rehabilitation project. These barriers affect the implementation of project activity most strongly (but not the baseline).
4. Lack of private capital and unattractiveness for investors is demonstrated by the 'non-investment' ranking of the country by an International rating agency (Standard & Poor).
5. The low collection ratio means lower revenue, which in turn means reduced ability to repay EBRD loan
6. The devaluation of $ vis-à-vis € is the main reason why the project ran into financial troubles, as the loan was denominated in $ while the payments were denominated in €. As $ devalued, the value of financing available became less than sufficient to pay the contractors in €. The chart on page 20 amply illustrates this devaluation affect.

7. Low tariffs resulted in low revenues for the project company, making it extremely challenging to repay the loan taken by EBRD for the rehabilitation project.

Detailed description and step-by-step method has to be followed to determine the baseline scenario for the project activity is presented below:

Step 1: Identify realistic and credible alternative baseline scenarios for power generation:

Sub-step 1a: Define alternative scenarios to the proposed CDM project activity:

The methodology requires that Step 1 of the "Combined tool to identify the baseline scenario and demonstrate additionality" is applied for this. There are two plausible options for the project activity:

P1: The project activity not implemented as a CDM project

P2: The continuation of the current situation, i.e. to use all power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance. The additional power generation under the project activity would be generated by existing and new grid-connected power plants in the electricity system. The project activity in such a situation would be undertaken without being registered as a CDM project activity – but undertaken at a later point in time. This future date/point-in-time is defined as $DATE_{Baseline\,\mathrm{Re}trofit}$, which is determined below in a step by step manner.

The methodology (ACM0002 Version 12.1.0) suggests an additional option (P3), which is:
All other plausible and credible alternatives to the project activity that provide an increase in the power generated at the site, which are technically feasible to implement. This includes, inter alia, different levels of replacement and/or retrofit at the power plant/unit(s). Only alternatives available to project participants should be taken into account.

This option (P3) is not applicable for the project participant as opposed to the above mentioned two options (P1) – Project not implemented as CDM and (P2) – Status Quo (continuation of current situation). Additional justification is provided below:

Justification for eliminating Option P3:

From the project developer's (Engurhesi) perspective there are only two practical options: either to implement the rehabilitation project or not to implement the rehabilitation project.

As such, some routine maintenance work has always been conducted at the project site to make sure that the equipment continues to keep performing (as of 2005, the plant was expected to have a lifetime till 2022, or at least 17-18 years). However, the units were both de-rated (operating at lower than optimal/maximum possible capacity) and were also operating inefficiently (i.e. for the same water flow through the turbines, the Enguri HPP would generate less power than what would be possible after the rehabilitation works). Undertaking partial rehabilitation work was not a possibility as the generation units are sequential and for the intended objective to be achieved all the sequence of equipment (turbine, generator) need to be rehabilitated along with the auxiliaries.

For these reasons, undertaking only partial rehabilitation work or any other alternative (P3) is not a possibility for the project proponent and the two options that are (Option P1 and P2) have already been considered as part of the Baseline Identification process

Determination of $DATE_{Baseline\,Retrofit}$ for defining Option P2:

As per ACM0002 (Version 12.1.0): The plausible baseline scenario (P2) is defined as following:
In the absence of the CDM project activity, the existing facility would continue to provide electricity to the grid ($EG_{Baseline}$ in MWh/year) at historical average levels ($EG_{historical}$, in MWh/year), until the time at which the generation facility would likely be replaced or retrofitted ($DATE_{Baseline\,Retrofit}$). From that point of time onwards, the baseline scenario is assumed to correspond to the project activity, and baseline electricity production ($EG_{Baseline}$) is assumed to equal project electricity production (EG_y, in MWh/year), and no emission reductions are assumed to occur.

The step by step process for identifying the baseline scenario follows after determining the most important factor $DATE_{Baseline\,Retrofit}$ for the project activity.

As per ACM0002 (Version 12.1.0) in order to estimate the point in time *($DATE_{Baseline\,Retrofit}$)* when the existing equipment would need to be replaced in the absence of the project activity, one of the following approaches has to be taken:
(a) The typical average technical lifetime of the type equipment may be determined and documented, taking into account common practices in the sector and country, e.g. based on industry surveys, statistics, technical literature, etc.
(b) The common practices of the responsible company regarding replacement schedules may be evaluated and documented, e.g. based on historical replacement records for similar equipment.

For the proposed project activity the approach (a) has been applied to derive the value of $DATE_{Baseline\,Retrofit}$. For this, information on the grid connected hydro plants in Georgia and information on their operating history before those plants were rehabilitated (wherever applicable) was used. There were a few units that had never been rehabilitated. The results of information based on the operating history information of 24 units at 7 hydro plants in Georgia are given below:

Results	Hours of Operation prior to Rehabilitation
Minimum	220,150
Maximum	308,150
Mean	261,351
Median	256,168
Range of Hours	220,150 - 308,150

The above results are based on the detailed information about the operating history of plants, and the point of time when these units were sent for rehabilitation (where applicable).

SN	Plant Name	Unit No.	Hours of Operation prior to Rehabilitation	Year of completion of Rehabilitation
1	Rioni HPP	Unit No. 1	277,513	1998
		Unit No. 2	268,070	1995

SN	Plant Name	Unit No.	Hours of Operation prior to Rehabilitation	Year of completion of Rehabilitation
		Unit No. 3	305,357	2005
		Unit No. 4	290,222	2000
2	Gumati HPP I	Unit No. 1	255,121	Never Rehabilitated
		Unit No. 2	244,223	Never Rehabilitated
		Unit No. 3	234,351	2006
		Unit No. 4	242,320	Never Rehabilitated
3	Gumati HPP II	Unit No. 1	254,410	In Progress
		Unit No. 2	249,119	In Progress
		Unit No. 3	251,788	In Progress
4	Shaori HPP	Unit No. 1	270,140	Never Rehabilitated
		Unit No. 2	261,252	Never Rehabilitated
		Unit No. 3	257,214	Never Rehabilitated
		Unit No. 4	250,398	Never Rehabilitated
5	Lajanuri HPP	Unit No. 1	250,311	Never Rehabilitated
		Unit No. 2	245,524	2008
		Unit No. 3	248,245	Never Rehabilitated
6	Dzverula HPP	Unit No. 1	220,150	2000
		Unit No. 2	265,315	Never Rehabilitated
		Unit No. 3	262,123	Never Rehabilitated
		Unit No. 4	260,543	Never Rehabilitated
7	Atsi HPP	Unit No. 1	308,150	Never Rehabilitated
		Unit No. 2	300,556	Never Rehabilitated

The earliest operational lifetime at which any hydro plant's unit in Georgia was rehabilitated is 220,150 hours. Thus 220,150 hours has been chosen as $DATE_{Baseline\,\mathrm{Re}trofit}$ for the proposed CDM project activity.

The project start date is chosen January 2006. The table below gives information on each units operating life at the end of 2005:

	At the end of 2005	Lifetime before rehabilitation	Remaining Lifetime of Units (Hours) at end of 2005	Expected lifetime years	$DATE_{Baseline\,\mathrm{Re}trofit}$
Unit 1	97,266	220,150	122,884	24.6	2029.6
Unit 2	108,619	220,150	111,531	22.3	2027.3
Unit 4	111,251	220,150	108,899	21.8	2026.8
Unit 5	131,221	220,150	88,929	17.8	2022.8

To determine the expected lifetime in "years", an annual operation of 5,000 hours has been considered. The average annual operation of each of the four units has been considered taking into account the historic annual average generation data of these four units, which are given in the table below:

Unit Number	in 2003	in 2004	in 2005	Average
Operation of Unit 1 in the year (hours)	3,981	5,567	4,571	4,706
Operation of Unit 2 in the year (hours)	5,108	4,518	2,735	4,120
Operation of Unit 4 in the year (hours)	6,470	4,409	5,640	5,506
Operation of Unit 5 in the year (hours)	4,539	4,945	6,858	5,447
Average Operation	**5,025**	**4,860**	**4,951**	**4,945**

Thus, to be conservative $DATE_{Baseline\,\mathrm{Re}trofit}$ for all the units has been taken as 31/12/2022.

The project proponent have decided to opt for a 10 year CDM crediting period, which ends before the $DATE_{Baseline\,\mathrm{Re}trofit}$ of the CDM project activity.

***Outcome of Step 1a*: List of plausible alternative scenarios to the project activity:**

P1: *The project activity implemented but not as a CDM project*

P2: *The continuation of the current situation*, i.e. to use all the power generation equipment that was already in use prior to the implementation of the project activity and undertake business as usual maintenance. The additional power generation under the project activity would be generated by existing and new grid-connected power plants in the electricity system. The project activity in such a situation would be undertaken without being registered as a CDM project activity – but undertaken at a later point in time, which is $DATE_{Baseline\,\mathrm{Re}trofit}$ and as determined above equates to 31/12/2022.

***Sub-step 1b*: Consistency with mandatory laws and regulations:**
In the following section we will determine if any mandatory laws and/or regulation would prevent any of the baseline option from being implemented:

***P1:** The project activity not implemented as a CDM project*
In this alternative, the refurbishment of Unit # 2, Unit # 4, Unit #1 and Unit #5 of Enguri HPP is undertaken but not as a CDM project activity. Thus, Engurhesi does not receive any revenues from the sale of CERs and relies only on revenues from power sales to finance the rehabilitation project. This alternative is in compliance with all applicable legal and regulatory requirements.

***P2**: The continuation of the current situation, i.e. to use all the power generation equipment that was already in use prior to the implementation of the project activity and undertake business as usual maintenance.*
The additional power generation under the project activity would be generated by existing and new grid-connected power plants in the electricity system. The project activity in such a situation would be undertaken without being registered as a CDM project activity – but undertaken at a later point in time, which is and as determined above equates to 31/12/2022.
The non-rehabilitation is not prohibited by law. Hence, this option is also in compliance with mandatory laws and regulations of Georgia.

***Outcome of Step 1b*: List of plausible alternative scenarios to the project activity:**
Both options P1 and P2 are consistent with mandatory applicable laws and regulations.

Step 2: Barrier Analysis
As required by methodology ACM0002 (Version 12.1.0), we will apply Step 2 of the "Combined tool to identify the baseline scenario and demonstrate additionality"

The barrier analysis is being conducted to demonstrate that the project activity faces barriers that:
(a) Prevent the implementation of this type of proposed project activity; and
(b) Do not prevent the implementation of at least one of the alternatives.

***Sub-step 2a*: Identify barriers that would prevent the implementation of alternative scenarios**

The following barriers are identified for this project activity:

- Investment barriers
    - Lack of Private Capital
    - Risks due to low collection rates
    - Exchange Rate Risks
    - Risks due to level of tariff

Outcome of Step 2a: All the barriers that would prevent the implementation of at least one or more of the alternative scenarios have been identified. These barriers are:

- Investment barriers
    - Lack of Private Capital
    - Risks due to low collection rates
    - Exchange Rate Risks
    - Risks due to level of tariff

Sub-step 2b: Eliminate alternative scenarios which are prevented by the identified barriers:

1. ***Investment barrier (Lack of Private Capital):***

As per the 'Combined tool to identify the baseline scenario and demonstrate additionality', sub-step 2a. Investment barriers, page 7. (EB 60, Annex 7): "*No private capital is available from domestic or international capital markets due to real or perceived risks associated with investments in the country where the project activity is to be implemented,* ***as demonstrated by the credit rating of the country or other country investment reports of reputed origin***".

In the case of the country of Georgia and the Enguri HPP project:

- No private capital has been available from domestic or international markets due to real and perceived risk associated with investments in Georgia. This is demonstrated by the credit rating of Georgia provided, for example, by Standard & Poor's.
- In December 2005, Standard & Poor's awarded Georgia long-term sovereign credit rating B+ and short-term sovereign credit rating B[3]. In November 2006, Standard & Poor's sovereign long term investment rating on both local and foreign currency in Georgia was also B+ (and as of September 2008 had been further downgraded to B). The Standard & Poor's rating varies on a scale of values between CCC- (the lowest) and AAA+ (the highest). The range between AAA to BBB is for investment grade countries, while BB to C are non-investment grade.

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[3] Credit Rating Agency Gives 'Positive Outlook' on Georgia: http://www.civil.ge/eng/article.php?id=11302

- Georgia is still a non-investment grade country according to Standard & Poor's[4].

Furthermore, investments in the Abkhazia region where the project is located have been perceived as risky, because of the political and social instability in the area, as reported by the UN Security Council in its reports[5].

In other sections of the PDD, it is mentioned that the project company had access to both a national loan (USD 100,000 from Georgian Procredit Bank) and EBRD loans. Yet, the investment barrier (lack of private capital) remains a key obstacle to the project's implementation. The main arguments for this statement are detailed below.

In December 2001, Engurhesi signed a loan agreement with the European Bank for Reconstruction and Development (EBRD), amounting to USD 14.8 million. This loan was contracted to "rebuild" Unit 3, replace outdated auxiliary and control equipment (transformers, etc.), and perform general maintenance only on two more units (Unit 2 and Unit 1). The EBRD loan was to be disbursed in US Dollars (the exchange rate was 1\$=1.116€ at the time of signing).

The contract with Voith-Siemens was signed in November 2002. Most of the contractors' costs were to be paid in Euros.

The works on Unit 3 (which is not part of the proposed CDM project) started in 2003. While rehabilitating Unit 3, it was demonstrated that all the other units could be technically upgraded (and not only repaired as originally envisioned), if more investment was provided. Yet, the project was already experiencing financial difficulties due to the following reasons:

i. The US\$ experienced a drastic devaluation of about 30% vis-à-vis the Euro between 2001 and 2006 (as described in detail below, under "Investment barrier 3: Exchange Rate Risks");
ii. Increased costs were incurred due to delays in the schedule of rehabilitation works[6],
iii. Increased costs were further caused by the necessary scope expansion for the rehabilitation works[7]

Estimated US\$1.1 million shortfall was recognized for the rehabilitation work on Unit 2 alone.[6]

As a result, by the end of 2005, Engurhesi had completed works on Unit 3 but was unable to start works on Unit #2, let alone Unit #1 (which was planned to undergo maintenance 13-14 months afterwards). These financial difficulties resulted in Engurhesi failing to pay the project contractors which caused strikes and further delays in the schedule. The breach of several financial terms in the loan agreement was confirmed by Engurhesi in their Quarterly Reports of 2004 and 2005 (referenced in the section B.5 below).

On 7 December 2005, Voith Siemens issued a Preliminary Notice on Termination of Contract due to non-payment by the Employer within the allowed timeframe. On 12 December 2005 works on site stopped completely, and the contractors' and sub-contractors' staff were demobilized and left the site[8].

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[4] Bloomberg 'Georgia Sovereign-Debt Rating Raised One Notch to BB- by S&P': http://www.businessweek.com/news/2011-11-22/georgia-sovereign-debt-rating-raised-one-notch-to-bb-by-s-p.html

[5] UN Secretary-General's reports: http://www.un.org/docs/

[6] Minutes of Meeting of the Board of Directors of "Engurhesi" Ltd on December 25, 2005, page 3

[7] Minutes of Meeting of the Board of Directors of "Engurhesi" Ltd on December 25, 2005, page 4

The reasons for cessation were two-fold: (i) the non-payment of the contractors' invoices and (ii) security issues. Contractors refused to resume work unless both the security and financial issues were addressed. In this context, Engurhesi took several steps to resolve the situation:

On December 21, 2005, as evidenced by the Minutes of the Board Meeting, the financial problems of the project were discussed and it was agreed that "*additional funding must be requested to complete the rehabilitation program*". CDM revenues were identified as a way to "*support mitigation of financing deficit for Unit 2 and for remaining units*" i.e. to cover the financing gap left by the currency devaluation and to co-finance (together with prospect of EBRD additional funding) rehabilitation of Unit #1, Unit #4, and Unit #5.

Following this meeting, Engurhesi started negotiations with the EBRD to seek additional funding. In the meantime, the company applied to a domestic bank, ProCredit Bank, for an emergency loan. However, this approach presented a number of issues:

- In general, the interest rates applied to loans in Georgian Lari by Georgian commercial banks to industrial public sector companies were given at a level of 16.9% in 2006, which were considered very high by Engurhesi (Source: National Bank of Georgia, Bulletin of Monetary and Banking Statistics (January-September, 2006). The interest rate applied by ProCredit Bank was 15%[9].
- The loan terms are generally too short for a long term investment such as the refurbishment of a major power plant including capacity addition of approximately 200MW. The loan from ProCredit Bank was due to be repaid in 12 months[10].
- Georgian banks are too small to provide loans for such a large rehabilitation project, including capacity addition of approximately 200MW. ProCredit Bank was able to provide only USD 100,000 of the requested USD 200,000[11].

As a result, the domestic loan that was obtained was lower than requested and not sufficient to cover the deficit for works already undertaken, let alone the remaining rehabilitation works. Also, the loan conditions provided by domestic banks made it a non viable option to fund the entire Enguri project. The ProCredit Loan was merely intended to bridge the period until the Second Novation Agreement (which explicitly requires the seeking of CDM finance) provided much larger fund to complete the work.

After months of negotiations, the Second Novation Agreement was signed in 2006 for an additional USD 10 million. Its purpose was to finance the deficit for completion of rehabilitation works on Units 2 and 1, and undertake the refurbishment works for the other units, with an explicit requirement to seek CDM financing to serve as a key source of revenue to meet the loan repayment obligations. Once the additional funding was secured via the Second Novation Loan – which mentions all units covered by the proposed CDM project – it was possible to move on to rehabilitating Unit #2 and subsequent units in a schedule (i.e. Unit #1, Unit # 4 – later swapped with Unit #1, and Unit #5).

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[8] Status Protocol. CW 47-29 dated 21.12.2005, and Voith Siemens Letter on work stop and restart

[9] 2006 Loan Agreement with ProCredit Bank; page 1

[10] 2006 Loan Agreement with ProCredit Bank; page 1

[11] Letter to ProCredit Bank of 22 Dec 2005; and 2006 Loan Agreement with ProCredit Bank (page 1)

As such, the Investment barrier (Lack of Private Capital) has been a continuous issue. Securing additional funding was made possible by the prospects of having supplemental sources of revenues from the CDM.

Option P1: **Severely affected** by Investment Barrier (Lack of Private Capital)
Option P2: This is the current scenario and is not affected by the Investment Barrier (Lack of Private Capital)

2. Investment Barrier (Risks due to low collection rates)

Low collection rates in Georgia (includes all the plants in the Georgian Grid)
As shown in the table below, the low level of collection adds further barriers to investment in power sector projects in the country, reporting even a slight declining trend between years 2004 and 2005. In 2004 – the overall collection stood at 57.6%, which reduced by approximately 1% to 56.7% in 2005.

In 1000 Lari	Jan	Feb	Ma	Apr	May	June	July	Aug	Sep	Oct.	Nov.	Dec.	Total
Total billed 2005	123,853	71,803	54,399	51,048	44,234	37,367	29,009	16,510	29,560	26,666	35,483	51,416	**571,347**
Collected as % of Total 2005	15.8%	28.4%	39.6%	38.5%	41.9%	49.3%	64.5%	122.9%	66.1%	75.6%	65.8%	53.3%	**56.7%**
Total billed 2004	64,710	46,764	40,328	44,196	43,348	35,954	31,230	35,976	37,522	33,163	37,125	30,179	**480,495**
Collected as % of Total 2004	18.6%	42.2%	45.3%	49.5%	38.5%	40.3%	48.6%	53.0%	66.6%	48.3%	44.8%	28.3%	**57.6%**

Source: Sum of all total billed and total non collected energy payments from chart on website http://www.minenergy.gov.ge in the section Energy Statistics & Forecasts » Electricity » Combined Collections and Commercial Losses.

The overall collection rate has remained very low for Engurhesi (the project proponent). For the project plant (Enguri hydro project), collection ratio has averaged at less than 30% for the three full years prior to the start of the CDM project activity. The CDM revenues help mitigate this risk as carbon revenues are available for the incremental generation from the project activity, and electricity being exported to the grid, irrespective of the collection ratio for the electricity sent to the final consumers.

Low collection rate for Engurhesi Hydro Power Project (HPP):

In 1000 US Dollars	2003	2004	2005
Generation of Electricity in GWh	3,066.10	2,794.47	2,535.24
Total Billed	26,241.0	30,472.7	29,508.5
Collection	6,493.9	7,830.5	9,039.0
Collection Rate at Engurhesi	**24.75%**	**25.70%**	**30.63%**
Net loss for the reporting period	- 3,583.3	- 3,076.8	- 4,560.8

Source: Engurhesi Balance Accounts,

Thus, it is as yet unclear whether the Georgian electricity system will be immune from non-payment risk. The risk of non-payments for power generators, including Engurhesi, is likely to remain for years to come.

Option P1: **Severely affected** by Investment Barrier (Risks due to low collection rates), suitable debt covenants were also included to demand from Engurhesi to increase their overall tariff to a sustainable level. However, this debt covenant was constantly in breach.
Option P2: This is the current scenario and is not affected by the Investment Barrier (Risks due to low collection rates)

3. ***Investment Barrier (Exchange Rate Risks):***
This is the risk/barrier that has most affected the Enguri rehabilitation project. The main reason is that the 2001 EBRD Loan was disbursed in US Dollar, while most payments to the contractors were to be made in Euros. Exchange rate risk is the highest risk associated with any new investment in Georgia (Alternative P1), and it does not apply to status-quo (business as usual scenario) or Alternative P2.

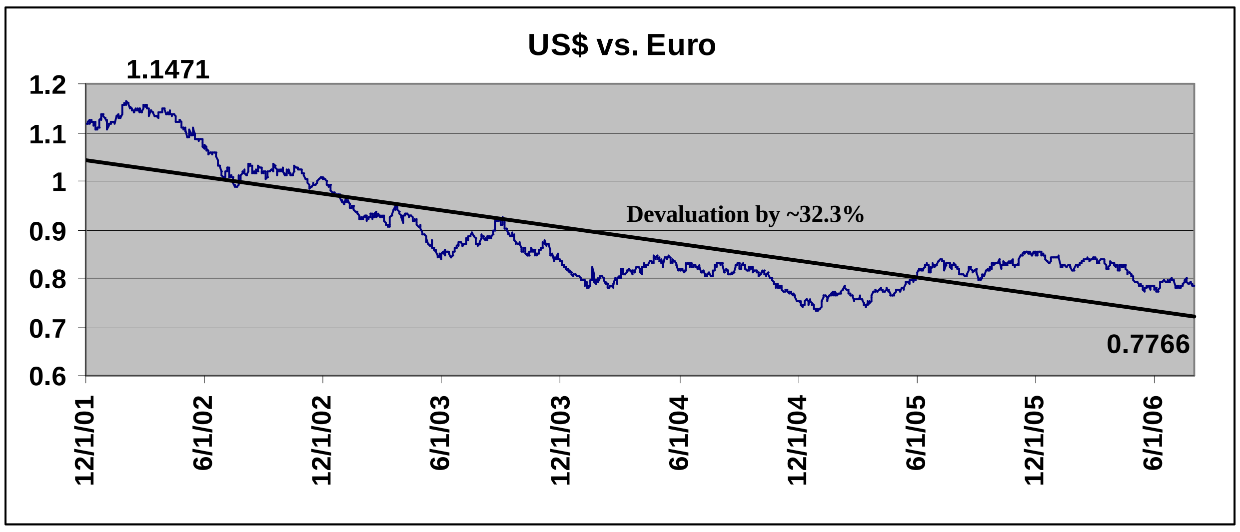
The EBRD loan of December 2001 was to cover the works of Enguri units in the following order: after Unit 3 (not included in the CDM project activity) Unit 2 and Unit 1 (NB: due to technical reasons, Unit 1 was later replaced by Unit 4 in the schedule). The overall work was expected to take 44 months in all (18 months for Unit#3, 13 months of Unit#2 and 13 months of Unit#4). The EBRD loan was to be disbursed in US Dollar and at that time (Exchange Rate: 1$=1.116€) the loan amount was expected to be sufficient to cover all project costs of the three units.

The contract with Voith-Siemens was signed in 2002. The work programme was phased in order to minimize disruptions to the plant operations. The works started on Unit 3 with the two other units to follow. Engurhesi had to pay the contractor (Siemens) mainly in Euros. At the time of contract signing with Siemens the US Dollar had devalued vs. the Euro (1$=1.005€), compared to the exchange rate that was in effect when the loan was signed.

Subsequently, the further devaluation of the US Dollar compared to the Euro (see graph below) meant that Engurhesi faced a financing shortfall.

The effect of currency devaluation is better illustrated by the 365 days average USD to EUR Interbank rates for the following key years (www.oanda.com/fxhitory) as well as the graph below:

- In the year 2000: 1US$ = 1.08500 Euro
- In the year 2002: 1USD = 1.06106 Euro (A drop by 02.21% over the base year 2000)
- In the year 2006: 1USD = 0.79703 Euro (A drop by 26.54% over the base year 2000)



The available loan (that was sanctioned in December 2001) was utilised to pay Siemens starting May 2003 (when works on Unit 3 started). While rehabilitating Unit 3, it was demonstrated that all the other units could be technically upgraded (and not only repaired as originally envisioned), if more investment was provided. Yet by May 2006 the US Dollar had devaluated vs. the Euro by approximately 30% compared to December 2001. Consequently, the US Dollar loan converted into Euro turned out to be sufficient only to cover the costs for auxiliaries and Unit 3, and to initiate works on Unit 2.

The cost of rehabilitating Unit 3 was initially estimated to represent approximately 50% of total costs as indicated in the Siemens contract. Works on Unit 2 and Unit 1 (later replaced by Unit 4) represented around approximately 25% each of the total costs (Ref: the copy of the original Contract with Voith Siemens Hydro Kraftwerkstechnic GmbH & Co.KG and the table below which calculates the share of each unit over the total costs).

Costs of rehabilitation as established in the contract with Siemens:

- Total rehabilitation of auxiliaries (including local transportation): EUR 2,492,233
- Unit 3: EUR 6,263,892 and USD 1,795,084 (for plant and equipment including mandatory spare parts supplied from abroad + EUR 1,299,679 (installation and other services)
- Unit 2: EUR 2,905,637 and USD 1,442,929 (for plant and equipment supplied from abroad) + EUR 906,394 (installation and other services)
- Unit 1 (as included in Siemens contract, later replaced with Unit 4): EUR 2,905,637 and USD 1,442,929 (for plant and equipment supplied from abroad) + EUR 906,394 (installation and other services)

	EUR	**USD**	**% of Each Unit over Total EUR costs**	**% of Each Unit over Total USD costs**
Auxiliaries Rehabilitation + Local Transportation	(2,060,534+276,458+ 155,241)	0	14.1%	
Total (Auxiliaries)	**2,492,233**	**0**		
Unit 3	(6,263,892+1,299,679)	1,796,084	42.8%	38%
Total (Unit 3)	**7,563,571**	**1,796,084**		

	EUR	USD	% of Each Unit over Total EUR costs	% of Each Unit over Total USD costs
Unit 2	(2,905,637+906,394)	1,442,929	21.6%	31%
Total (Unit 2)	**3,812,031**	**1,442,929**		
Unit 1 (then replaced with Unit 4)	2,905,637+906,394	1,442,929	21.6%	31%
Total (Unit 1)	**3,812,031**	**1,442,929**		
Total	17,679,866	4,681,942		

As a direct result of the currency devaluation, a financing shortfall of about 30% was recognized to complete rehabilitation of both Unit 2 and Unit 1 (later replaced with Unit 4). The impact of devaluation was aggravated by the need for additional funding to cover a revised scope of rehabilitation works at the remaining units (except Unit 3), which was not initially envisaged, but was identified during works on Unit 3.[12]

Moreover, because of these financial issues and the cessation of rehabilitation works on site in part due to the non-payment of the contractor's (Voith Siemens) overdue invoices, the project implementation experienced severe delays. Consequently, Engurhesi suffered from huge financial losses (opportunity cost) as units were not in operation for a much longer duration than originally anticipated when starting the works. For instance:

1. Work on Unit#3 was expected to be completed in 18 months when it took approximately 37 months to complete the rehabilitation work – *a delay of 19 months*
2. Work on Unit#2 was expected to be completed in 13 months when it took approximately 25 months to complete the rehabilitation work – *a delay of 12 months*

Option P1: Severely affected by Investment Barrier (Exchange Rate Risks)
Option P2: This is the current scenario and is not affected by the Investment Barrier (Exchange Rate Risks)

4. ***Investment Barrier (Risks due to level of tariffs):***

The Georgia National Energy Regulatory Commission (GNERC) regulates long-term tariffs for, among others, state-owned electric power plants.

In 2003-2005, the generation tariff applicable to Engurhesi was 2.13 Georgina tetri/kWh[13]. Such level was deemed low, and as such EBRD requested Engurhesi to apply for an increase of their overall tariff to a sustainable level. However, this debt covenant was constantly in breach. Indeed, covenant 3.01 (d) (i) of the "Status of Covenant Compliance of the Novation Agreements (October-December 2004)" refers to reaching the desired level of 1.5 US cents/kWh[14]. Using the exchange rate in effect at the end of 2004 (US$ 1 = Lari 1.77)[15], 1.5 US cents are equivalent to 2.66 tetri.

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[12] Documented in Minutes of Meeting of the Supervisory Board of Engurhesi Ltd, 25 December 2005

[13] Based on Engurhesi's records, as presented in the authorized document "Collection of Bills 2003-2005"

[14] **Ошибка! Источник ссылки не найден.**

[15] Historic rate: http://www.geres.ge/currency/rates.html?lang=en&d=27&m=12&y=2004&go.x=13&go.y=5

Even the tariff amounting to 2.13 Georgian tetri/kWh was far too low to make the project implementation financially attractive. At this tariff level, Engurhesi would have collected GEL 57,898,218 in 2004 and GEL 54,000,645 in 2005, as demonstrated in the table below[16]. Yet, the collection rate on average was 25.70% and 30.63%, accordingly.

Year	**2003**	**2004**	**2005**
Tariff level	**2.13**	**2.13**	**2.13**
Total Revenue Billed	55,106,242	57,898,218	54,000,645
Total Actual Collection	13,637,362	14,878,009	16,541,364
Collection %	27.75%	25.70%	30.63%

After converting GEL to USD[17], the collected amounts would equal: USD 6.57 million in 2003, USD 8.15 million in 2004, and USD 9.23 million in 2005. Considering the cost of the rehabilitation programme (as mentioned above), Engurhesi would have had to have put aside its total annual revenues for at least three consecutive years, if it had wanted to finance the project. And this is disregarding the regular maintenance and operation costs, as well as the debt repayment obligations of Engurhesi.

In June 2006, Enguri HPP's generation tariff was reduced from 2.13 Georgian tetri/kWh to 1.187 Georgian tetri/kWh. This reduction took place after project start date and does not influence existence of the barrier, yet it serves only as the additional comment referring to the risks arising from non-market nature of the tariff regulation in Georgia.

Option P1: **Severely affected by Investment Barrier (Risks due to low levels of tariffs)**: suitable debt covenants were also included to demand from Engurhesi to increase their overall tariff to a sustainable level. However, this debt covenant was constantly in breach. Even with the tariff of 2.13 Georgian tetri/project, option P1 could not be implemented, as discussed above.
Option P2: This is the current scenario and is not affected by the Investment Barrier (Risks due to low levels of tariffs)

Summarizing the Result of Sub-step 2(b):
The following table illustrates how the barriers discussed under step 2a prevent Alternative P1 from happening. However, alternative P2 is not affected from the above barriers and so is chosen as the baseline scenario for the proposed CDM project activity:

Barriers	**Alternative P1** ***Refurbishment of Units 1, 2, 4, and 5 but not as CDM***	**Alternative P2** ***Current situation, no refurbishment of Units 1, 2, 4, and 5 until*** $DATE_{Baseline\,Retrofit}$ = 31/12/2022.
Lack of capital and the country not being a high investment grade country.	Strongly affected. Lack of private capital may make investment in a rehabilitation project	Not affected This alternative would continue to remain applicable even if the barriers prevailed.

[16] Information included in the table is based on Engurhesi's records, as presented in the authorized document "Collection of Bills 2003-2005",

[17] Rates as of 31 Dec of a given year. Source:
http://www.geres.ge/currency/rates.html?lang=en&d=31&m=12&y=2003&go.x=7&go.y=8.

Barriers	Alternative P1 *Refurbishment of Units 1, 2, 4, and 5 but not as CDM*	Alternative P2 *Current situation, no refurbishment of Units 1, 2, 4, and 5 until* $DATE_{Baseline\,Retrofit}$ = 31/12/2022.
	implausible.	
Collection rates risk	Strongly affected, since its makes investment in the project highly risky. In the absence of good collection – the overall revenue and hence the debtor's ability to repay the loan would be severely affected. This would make investment in rehabilitation project highly implausible.	Not affected This alternative would continue to remain applicable even if the barriers prevailed.
Exchange rate risk	Strongly affected, since it makes investment in any new project highly susceptible to exchange rate variations.	Not affected. This alternative would continue to remain applicable even if the barrier prevailed.
Tariffs risk	Strongly affected, tariffs were never sufficient to cover the costs of rehabilitating the project without CDM.	Not affected Alternative P2 would continue to remain applicable even if the barriers prevailed.
Conclusion	***Barriers prevent Alternative P1.*** ***Alternative P1 is unviable.***	***Barriers don't affect Alternative P2 at all. Hence, Alternative P2 is baseline scenario.***

<u>Outcome of sub-step 2b of the Combined Tool:</u>

None of the identified barriers would impact the baseline scenario as strongly as the project activity that entails significant investment in an uncertain economic/market environment that prevailed in Georgia at the time of investment decision and the deteriorated investment environment that has continued ever since.

Thus:

- The baseline of the project activity is the current scenario, i.e. Units # 2, 4, 1 and 5 are not rehabilitated and these continue to generate electricity at the historical level till such time as $DATE_{BaselineRetrofit}$ (which has been identified as December 31, 2022) has reached
- The proposed CDM project activity (rehabilitation of Units # 2, 4, 1 and 5) faces several barriers that make investment in these projects prohibitively risky.

Thus, in December 2005 Engurhesi Ltd started considering other sources of finance to cover for the shortfall and be able to rehabilitate the remaining units (Unit#2, Unit#4, Unit#1 and Unit#5). Engurhesi started discussion with EBRD for financing the rehabilitation of its remaining units and to support

Engurhesi with the development of the CDM component for the project activity. The PIN for the project was prepared in early July 2006 and ICF was contracted to develop the CDM component of the Enguri project in September 2006.

A new financing agreement was concluded in December 2006 with EBRD to cover the deficit for completion of rehabilitation works on Units 2 and 1, and undertake the rehabilitation works on Unit 4 (later swapped with Unit 1) and Unit 5. This financing agreement fully incorporated the CDM component (Ref: Second Novation Loan Agreement between EBRD and Enguhresi dated 29 December 2006: Section 3.01 Other Affirmative Project Covenants states: "*undertake and/or procure that all necessary steps are taken to enable the Project to qualify for the Clean Development Mechanism and ensure that the funds raised through the CDM are used in priority for meeting the Borrower's and the Novation Project Company's obligations regarding the Project*".).

Therefore CDM revenues are essential to ensure investment in rehabilitation of Unit#2, Unit#4, Unit#1 and Unit#5, and CDM revenues help overcome the financial/investment barriers faced by the project activity.

As per the Combined Tool:
If there is only <u>one alternative scenario</u> that is not prevented by any barrier, and if this alternative is <u>not</u> the proposed project activity undertaken without being registered as a CDM project activity, then this alternative scenario is identified as the baseline scenario.

The alternative P2 is the only alternative that is not prevented by any barrier, and this alternative is not the proposed project activity undertaken without being registered as a CDM project activity – hence alternative P2 is the baseline option.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality):

As required by the guide for completing the CDM PDD and the proposed new baseline and monitoring methodology – following key assumptions and rationales have been made in this section:

a. Seriousness of CDM consideration and chronology of events is described to demonstrate the project start date and CDM seriousness;
b. Additionality of the CDM project activity is demonstrated by following steps of the procedure prescribed in the "Tool for the demonstration and assessment of additionality"...

Definition of the start date for the Enguri CDM project is governed by the Executive Board document EB41, Paragraph 67 (particularly, by the underlined text), which states:
"*In light of the above definition, the start date shall be considered to be the date on which the project participant has committed to expenditures related to the implementation or related to the construction of the project activity. This, for example, can be the date on which contracts have been signed for equipment or construction/operation services required for the project activity. Minor pre-project expenses, e.g. the contracting of services /payment of fees for feasibility studies or preliminary surveys, should not be considered in the determination of the start date as they do not necessarily indicate the commencement of implementation of the project. For those project activities which do not require construction or significant preproject implementation (e.g. light bulb replacement) the start date is to be*

considered the date when real action occurs. In the context of the above definition, pre-project planning is not considered "real action".

The Board further noted that there may be circumstances in which an investment decision is taken and the project activity implementation is subsequently ceased. If such project activities are restarted due to consideration of the benefits of the CDM the cessation of project implementation must be demonstrated by means of credible evidence such as cancellation of contracts or revocation of government permits. Any investment analysis used to demonstrate additionality shall comply with the requirements of paragraph 7 of the "Guidance on the assessment of investment analysis" (version 02)."

With relation to the underlined text above, a project activity that had ceased but was subsequently restarted needs to demonstrate two things to be eligible for CDM:

1. That the project activity implementation had actually ceased (two example documents are suggested as credible evidence in Para 67 above). Other credible evidence is clearly permissible.
2. That the project was restarted due to consideration of the benefits of CDM.

If these two elements are demonstrated, then the 'start date' becomes the date at which project implementation activity was re-started. Consequently, in the case of Enguri CDM project, the start date is **13 January 2006**, the date at which the contractor came back to the site and resumed the implementation of the rehabilitation work.

The following provides detailed chronology of events, together with referenced evidence.

(a) Seriousness of CDM consideration and chronology of events:

The Enguri rehabilitation project should be considered as a staged project, whereby each unit is rehabilitated upon the completion of the rehabilitation works at the previous unit (but never simultaneously) to minimize disruptions to the plant operations.

The table below indicates the chronology of events that took place prior to arising of the need to undertake the rehabilitation of Unit # 2, 4, 1 and 5 as CDM. In addition to events leading to CDM decision making, the table presents also continuing and real actions undertaken in parallel to the project implementation. These are in compliance with the EB62, Annex 13 to demonstrate CDM seriousness when undertaking the project.

#	Date	Event	Information	Remarks
1.	21/12/2001	Signing of the Loan Agreement with EBRD	Loan amounting to USD 14.8 million was to complete reconstruction of Unit 3 (which was out of operation since 1993)[18] and to perform general maintenance on Units	It is important to note that the loan was provided as a lump sum and that the loan agreement did not specify the detailed scope of works and how funds would be allocated.

[18] Unit 3 is not part of the CDM project scope, as works were fully completed with the EBRD loan and without support of CDM revenues),Yet, it is important to discuss its rehabilitation as it greatly impacted the amount of funding available for the rehabilitation of the other units and caused severe delays in the overall rehabilitation schedule

#	Date	Event	Information	Remarks
			1 and 2 (not technical upgrade)[19]. For technical reasons, Unit 1 was later replaced by Unit 4.	
2.	25/11/ 2002	Signing of the contract with Voith Siemens (key contractor)	The contract has been signed to undertake works on Enguri HPP Units.	**25 November 2002** is the **starting date** of the rehabilitation programme (not the CDM project). NB: the works on Unit 3 started in 2003.
3.	Q1 2004	18th Quarterly Project Report	These Quarterly reports are prepared by Engurhesi to report the status of Enguri rehabilitation works, including information related to project financing. (information about status of the covenants, related to project financing, is provided on page 18 onwards)	The project proponent was in breach of several financing covenants. This demonstrates dire financial situation of the project company, and barrier associated with financing (and ability to procure additional financing)
4.	Q2/ Q3 2004	19th and 20th Quarterly Project Report	Same as No. 1 (Page 25 onwards)	Same as No. 1
5.	Q4 2004	21st Quarterly Project Report (Extract on Status of Compliance of the Novation Agreements)	Same as No. 1	Same as No. 1
6.	17/12/ 2004	Minutes of Meeting # 4 of the Board of Directors of "Engurhesi" Ltd. 4.(a) Is original version, which is in Georgian	CDM Awareness CDM benefits were being considered "*to cover financing gap for completing the rehabilitation work*".	Compliance with EB62-Annex 13, Paragraph 6(a). As shown in the graph above (section B.4), the US Dollar (in which Loan Agreement was denominated) had already devalued vs. the Euro (currency in which the contractor's invoices were due); thus creating financing gap.

[19] Note: the scope of work to be conducted under the EBRD loan differs drastically from the CDM project activity. First of all, two more units (Units 4 and 5) are included in the CDM project. More importantly, the CDM scope of work on Units 1 and 2 goes beyond what was planned under the EBRD loan. Instead of only carrying out general maintenance on the existing equipment of Units 1 and 2, the CDM project activity proposes to fully upgrade the installations, following the example of Unit 3.

#	Date	Event	Information	Remarks
		4.(b) Is English translation		
7.	Q1 2005	22nd Quarterly Project Report	Same as No. 1 (Page 23 onwards)	Same as No. 1
8.	Q2 2005	23rd Quarterly project Report	Same as No. 1 (Page 22 onwards)	Same as No. 1
9.	Q3 2005	24th Quarterly Project Report	Same as No. 1 (Page 17 onwards)	Same as No. 1 The financial problems faced by Engurhesi continued. The impact of devaluation was further aggravated by the need for additional funding to cover a revised scope of rehabilitation works at the remaining units, which was not initially envisaged, but was identified during works on Unit 3.
10.	27/09/ 2005	Status Meet Protocol – 2005-09-27; Internal meeting within Voith Siemens (VSH)	Point 1.2 "Suspension of Contractor's Activities" The project work was suspended on 22 Sep 2005 by sub-contractors working for Enguri Hydro Rehabilitation work due to non-payment of outstanding salaries.	This demonstrates financial barriers faced by the project proponent.
11.	01/11/ 2005	Notification of Suspension due to late Payments from the Employer. The document is from VSH) to Engurhesi.	The letter notified Engurhesi of the possible suspension of the contract if the outstanding amount was not covered within 28 days.	This adds additional credibility to financial difficulty faced by the project proponent. It demonstrates financing barrier faced by the project proponent.
12.	19/11/ 2005	Status Meet Protocol – 2005-11-18	Point 1.1 "Suspension of Planned Start of Unit 2 " Work was disrupted again due to repeated delays of payments to sub-contractors of Siemens. NB: If the delay is beyond 28, then as per 'General Conditions of Contract (GCC) 42.3.1. – the contract could be terminated.	This demonstrates continued financial barriers faced by the project proponent. The employer (Engurhesi Ltd.) planned for the works on Unit 2 to start on 14 December 2005. However, the contractor rejected this date because delays had occurred due to the non-payment of salaries. The contractor decided that a new start date would be discussed at the

#	Date	Event	Information	Remarks
				beginning of 2006 if financial issues had been resolved.
13.	07/12/ 2005	Preliminary Notice on Termination of Contract due to non-payment by the Employer	The letter states that per the GCC 42.3.1. the contract is liable to cancellation, as the payment had not been made for 28 days after receiving the Notice of Suspension. Even when the work was ceased the employer (Engurhesi) was subject to additional penalties for delay in work and interest charge for delay in payments. This situation made it critical for Engurhesi to re-start the work as soon as possible.	This demonstrates continued financial barriers faced by the project proponent.
14.	12/12/ 2005	Demobilisation of staff from the project site	On 11 December 2005, the VSPO (contractor's) car was attacked on the way back from Zugdidi to Saberio (inside Abkhazia). During that incident the security chief Mr. Shish lost his life and several persons in the car were injured. Consequently, on 12 December 2005 works on the ground stopped completely and all Voith Siemens/VSPO personnel left the Enguri site to Tbilisi on 12 December 2005 and went back to Germany on 14 December 2005 This is documented in the Status Protocol CW47-47, dated 21 December 2005.	The financial barriers were aggravated by the security issues. As a result, on 12 December 2005 works on the ground stopped completely, and the contractor's and sub-contractors' staff were demobilized and left the site. After this date, nothing was happening on site. As such, **12 December 2005** is treated as the **cessation date** of rehabilitation works (as required by EB41, Para 67). NB: The EB guidance ("*the cessation of project implementation must be demonstrated by means of credible evidence **such as** cancellation of contracts or revocation of government permits*") is generic and allows using other evidence to demonstrate the cessation of works.

#	Date	Event	Information	Remarks
15.	19/12/ 2005	Email Communication: ENG; Security measures to be implemented; VSHK/PIU-0449	Email communication from VSH to Engurhesi regarding security issues at the project site, which is at a disputed location within Georgia.	
16.	20/12/ 2005	Loan Drawdown Advice (from EBRD to Engurhesi) – The payments are made directly to VSH (Disbursement Application # 801)	The payments were made by EBRD to VSH to cover the outstanding payments due towards works done on Unit # 3. This is a payment of € 103,348.60 (US$ 124,276.69)	At the time of EBRD Loan signing (**2001**) → 1US$ = 1.116€ • EC Grant: € 5million (for Unit 3 only) -> $ 4.48 million • EBRD Loan: $ 14.8million • $ Total value = $ 19.28 million • Own contribution from Engurhesi required (5%) of project cost = $ 1.020 million.

[20] 1.The cost of rehabilitation for Unit # 2 and Unit # 4 has been indicated based on the expected costs that were originally agreed upon in November 2002 at the time of contract signing plus any increase in scope of work due to new areas of rehabilitation recognized (while conducting the rehabilitation of Unit 3). However, by this time the project was clearly three years delayed and much of the delay was attributed to the financial difficulty being faced by Engurhesi. Hence, the project developer would have expected a cost escalation request from Voith-Hydro, even if only owing to inflation effect. As discussed earlier, even at a rate of inflation of 6%, over the base cost of US$ 5.79 million – the new expected cost to be borne for rehabilitation of Unit # 2 and Unit # 4 would be US$ 6.89 million each. Thus, a total of US$ 13.79 million were expected to be spent as part of the original contract of which funding of only US$ 5.9 million was available. Thus, even with the available funding it might not have been possible to fund the rehabilitation of the next unit (Unit # 2) alone.

[21] Initially (in Nov 2002) it was expected that the rehabilitation works on Units #4 (later swapped with Unit #1) and #5 would be started soon after rehabilitation works on the earlier units have been completed by end of 2006, i.e. by early 2007. However, by the time of CDM start date (January 2006) it was clear that the work on Units #4 (later swapped with Unit #1) and #5 won't be started earlier than 2010. This would led to cost escalation owing to *inter alia* inflation. Considering these adjustments the expected cost of rehabilitations of Units # 4 (later swapped with Unit #1) and #5 were US$ 9,868,011 for each of the units as of December 2005. Or a total of US$ 19,736,022 only for the two new units (Unit # 4 – later swapped with Unit 1, and Unit # 5)

#	Date	Event	Information	Remarks
17.	20/12/2005	Loan Drawdown Advice (from EBRD to Engurhesi) – The payments are made directly to VSH (Disbursement Application # 802)	The payments were made by EBRD to VSH to cover the outstanding paymentsfor works done on Unit # 3 This is a payment of US$ 168,264	**Total funds allocated: $20.3 million** Total Project Costs **(2002)**: • Euro Payment: € 17,679,867 (€ 17.68 million or $ 17.59 million @ 1$ = 1.005€) • Payment: $ 4,681,942 ($4.68 million) **Total Project costs: $ 22.3 million** Thus, by the time the contract was awarded (11 months after novation loan – the shortfall in financing had already reached about $ 2 million
18.	20/12/2005	Loan Drawdown Advice (from EBRD to Engurhesi) – The payments are made directly to VSH This is payment of Grant (Disbursement Application # 207)	The payments were made by EBRD to VSH to cover the amount due towards works done on Unit # 3 This is a payment of € 551,194.40	**2005** Total amount of loan + grant remaining after these payments: $5.9 million (as documented in the EBRD Loan Drawdown Notice as of 31 December 2005) (on 20/12/2005 → 1US$ = 0.8326 €) • EC Grant: € 0 • EBRD Loan: $ 5.9 million (30% of original loan amount) Amount of work remaining **(2005)**: Total Funding Needed (excluding the rising interest costs + costs for auxiliaries/transport): **$ 11.58 million** • Unit 2: $ 5.79 million o *$ 0.55 million Increased Cost* o *$ 5.24 million Original Cost* • Unit 1 (later replaced with Unit 4): $ 5.79 million o *$ 0.55 million Increased Cost* o *$ 5.24 million Original Cost* **Shortfall due to Devaluation of Currency and Increased Project Cost: $ 5.68 million** (*$ 11.58mln - $ 5.9mn*). Actual deficit, however, was

#	Date	Event	Information	Remarks
				expected to be much higher due to the delays in rehabilitation activities[20]. Additional information on expected costs for rehabilitation of the remaining units (Unit #4 – later swapped with Unit #1, and Unit #5) has been provided in footnote.[21]
19.	-	Contract Engurhesi Ltd – Voith Siemens (For Cost Comparison)	It contains information about original project costs	This substantiates project costs as indicated above.
20.		Collections 2003 – 2005	The overall collection by Engurhesi was extremely poor • 2003: 24.75% • 2004: 25.70% • 2005: 30.63% As demonstrated earlier in the PDD, this is about half of the collection ratio for the whole Georgian grid.	This demonstrates the financial barrier faced by Engurhesi to be able to repay loan and to be able to raise any new financing (more so with heightened security concerns at Abkhazia region where the project is located). Constant breach of covenants (including increasing the collection ratio).
21.	21/12/ 2005	Minutes of Meeting # 19 of the Board of Directors of “Engurhesi” Ltd. 18.(a) Is original version, which is in Georgian 18.(b) Is English translation	CDM Awareness Financial issues were discussed and Engurhesi agreed that”*additional funding must be requested to complete the rehabilitation program*”. CDM benefits were being considered as a way to “*support mitigation of financial deficit* ***for Unit #2 and for remaining units***”. At this Board’s Meeting, the Engurhesi committed to starting negotiations with EBRD for additional funding, with the promise of seeking project registration under the CDM.. The subsequent discussions	Compliance with EB62-Annex 13, Paragraph 6(a) The project work was already ceased at project site owing to severe financial problems faced by the project proponent for over 24 months, as well as due to security threats at the project site. The Board also recognized the need to provide additional funds (€ 461,000 *or US $ 0.55million*) for rehabilitation work on Unit # 2 alone. CDM consideration was made prior to any work being started on any of the units covered by the CDM project scope (Unit #2, Unit #1, Unit #4, and Unit #5). Hence, any rehabilitation work taken on four units was possible due to CDM consideration only.

#	Date	Event	Information	Remarks
			led to EBRD eventually providing additional funds to Engurhesi. The loan document includes covenant requiring that Engurhesi develops the Enguri rehabilitation project as a CDM project.	This is evident from EBRD extending additional funding amounting to $ 10 million (New Commitment) in Second Novation Loan, which covers rehabilitation of units which are under the proposed CDM project scope. Discussions with EBRD were started at this stage for CDM and it was only due to CDM that Engurhesi could continue with the project. EBRD loan was finally sanctioned in December 2006 (one of the covenant requires that CDM revenue be used on priority to repay the EBRD loan).
22.	22/12/ 2005	Letter requesting emergency loan from a Domestic Bank in Georgia (Procredit Bank)	This emergency loan was requested to to cover the immediate financing gap ((i) ongoing operation costs and (ii) ongoing rehabilitation works). .	This document serves as additional evidence that real step to restart rehabilitation of the project activity. Yet (as discussed in section B.4), the domestic loan that was obtained was lower than requested and not sufficient to cover the deficit for works already undertaken, let alone the remaining rehabilitation works. Also, the loan conditions provided by the domestic banks made it a non viable option to fund the entire Enguri project. It was merely intended to bridge the period, until the Second Novation Agreement (which explicitly requires the seeking of CDM finance) provided much larger fund to complete the work.
23.	13/01/ 2006	Return of contractor staff on site	Email communication re: Enguri: follow-up mobilizing of Contractors Staff; VSHK/PIU-0457, in which VSH is stating that they will resume work on the project site from 13/01/2006. This date was also confirmed by the Voith Siemens in a	Work resumed after being ceased, once all the pending payments had been made and when the project proponent managed to address the security issues associated with the project activity too. **13 January 2006** is taken as the **CDM start date** in compliance with EB 41, Paragraph 67, since the

#	Date	Event	Information	Remarks
			separate letter on project cessation and restart, which was shown to the DOE.	project activity restarted after the firm commitment of the project proponent to seek CDM finance.
24.	12/09/ 2006	ICF Contract with EBRD to undertake CDM for Enguri rehabilitation project	This is to demonstrate the EBRD was seriously involved in getting the CDM status for this project activity before the final second novation loan was signed in December 2006.	Compliance with EB62-Annex 13, Paragraph 6(b)
25.	29/12/ 2006	Second Novation Loan being sanctioned to Engurhesi	The second novation loan lends additional US$ 10 million to cover all financing shortfall that the project had run into due to devaluation of currency, increased costs and delays (leading to interest costs). The Loan funding covers all four units included in the CDM project scope (as shown in the Schedule 2 to Loan Agreement– "Categories and Drawdowns").	The CDM component was very important aspect of financing (Paragraph (e) in Section 3.01. "Other Alternative Project Covenants": *"undertake and/or procure that all necessary steps are taken to enable the Project to qualify for the Clean Development Mechanism and ensure that the funds raised through the CDM are used in priority for meeting the Borrower's and the Novation Project Company's obligations regarding the Project"*. Despite the constant breach of covenants EBRD was able to lend to Engurhesi only due to the promise that CER revenue will be used to repay its loan (which are independent of the collection ratios).
26.	25/05/ 2007	Carbon Mandate Letter (CML) signed between Engurhesi and ICF	This is to demonstrate that Engurhesi was seriously seeking to secure CDM finance.	Compliance with EB62-Annex 13, Paragraph 6(b) Note: Multilateral Carbon Credit Fund has been established by EBRD and EIB[22]. On behalf of the MCCF, the carbon transaction with Engurhesi was negotiated by ICF.
27.	5/07/ 2007	Email of Engurhesi to DNA	Application for the Georgian Letter of Approval	Compliance with EB62-Annex 13, Paragraph 6(b) Application for the LoA requires several documents, including the PDD. Thus, time was needed to put

[22] Details on MCCF: http://www.ebrd.com/pages/sector/energyefficiency/sei/carbon/markets.shtml

#	Date	Event	Information	Remarks
				all documents in place.
28.	28/12/ 2007	Georgian Letter of Approval	Issuance of the host country approval to the project company.	Compliance with EB62-Annex 13, Paragraph 6(b)
29.	06/ 2009	Authorization letters of governmental bodies to Engurhesi	Issuance of approval letters to Engurhesi by: ▪ The Ministry of Justice (Jun 8, 2009) ▪ The Ministry of Finance (Jun 25, 2009) ▪ and State Enterprise Management Agency (State Supervisor of Enguri; Jun 30, 2009)	Compliance with EB62-Annex 13, Paragraph 6(b) The Project Company, being a state-owned company, was waiting for authorisation from the Georgian government to sign the Emission Reduction Purchase Agreement (ERPA), when hostilities broke out at the project location in Abkhazia in August 2008, causing the suspension of the Enguri project by the Ministry of Energy. The Government did meet again after new agreements have been put in place between authorities in Tbilisi and Abkhazia regarding Enguri and Vardnili.
30.	24/11/ 2009	Signed Emission Reduction Purchase Agreement	This is to demonstrate that Engurhesi has continued seeking to secure CDM finance.	Compliance with EB62-Annex 13, Paragraph 6(b).
31.	06/ 2010	Executing the legal documents, required by the ERPA	The ERPA includes a list of Conditions Precedent (CPs) that need to be met before the agreement is fully binding and enforceable. One of the CPs requires the Seller to execute specific legal side-agreements. This has been fulfilled in mid-2010.	Compliance with EB62-Annex 13, Paragraph 6(b).
32.	08/ 2010 – 01/ 2011	Selected emails on document collection in support of PDD	ICF was collecting evidence for supporting the PDD statements.	
33.	14/04/ 2011	ICF Contract with EBRD to assist validation of the Enguri rehabilitation project	ICF has been contracted to supervise the validation of the project under the CDM.	Compliance with EB62-Annex 13, Paragraph 6(b). Note: the negotiations of the contract started in mid-March. They were preceded with selection process for a validation DOE, that took place in

#	Date	Event	Information	Remarks
				Feb/Mar 2011.
34.	26/04/ 2011	Validation contract signed		Compliance with EB62-Annex 13, Paragraph 6(b).

Thus, it is amply demonstrated the Engurhesi management has been serious of CDM revenues and given the several investment barriers faced by them – it was the promise of carbon revenues that helped them raise capital for investment in the rehabilitation project and resume works to rehabilite Unit #2, #4, #1 and #5.

(b) Additionality of the CDM project activity:

As per the selected methodology ACM0002, the project proponent is required to establish that the GHG reductions due to the project activity are additional to those that would have occurred in the absence of the CDM project. To do so, the project proponent has to use the latest version of the "Tool for the demonstration and assessment of additionality"

<u>Step 1: Identification of alternatives to the project activity consistent with current laws and Regulations</u>

<u>Sub-step 1a: Define alternatives to the project activity</u>

In continuation with the discussion on baseline identification in the section B.4., the following credible alternative scenarios to the project activity have been identified:

- P1: The project activity implemented but not as a CDM project;
- P2: The continuation of the current situation, i.e. to use all power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance.

<u>Sub-step 1b: Consistency with mandatory laws and regulations</u>
Both identified alternative scenarios, P1 and P2, are in compliance with all mandatory applicable legal and regulatory requirements. The rehabilitation of hydro power plant units is not prohibited or required by the existing legislation.

The Tool allows project participants to select between Investment analysis or Barrier analysis, or use both. In case of this project activity, the project proponent has chosen to use Barrier analysis.

<u>Step 2: Investment analysis</u>
This step is not applied, as chosen by the project proponent.

<u>Step 3: Barrier analysis</u>

<u>Sub-step 3a: Identify barriers that would prevent the implementation of the proposed CDM project activity</u>
Amongst barrier types listed in the Tool (investment, technological, barriers due to prevailing practice, and other barriers), investment barriers have been identified as dominant in preventing the implementation of the proposed project activity. Particularly, the following investment barriers:

- Lack of Private Capital
- Risks due to low collection rates
- Exchange Rate Risks
- Risks due to level of tariff

These barriers are described in detail in the section B.4.

Sub-step 3b: Show that the identified barriers would not prevent the implementation of at least one of the alternatives

The rehabilitation of units at such a scale as in the proposed project activity requires large capital investment. Consequently, the identified investment barriers preventing to carry out the proposed activity would also apply to the P1 scenario: *The project activity not implemented as a CDM project*, hindering its implementation. Yet, scenario of P2: *The continuation of the current situation* would not be affected by investment barriers, as additional capital is not required to continue existing operations.

Step 4: Common Practice Analysis:

The common practice analysis has been conducted as an extra credibility check for the CDM project activity's additionality.

Sub-step 4a: Analyze other activities similar to the proposed project activity:

As explained in section B.4: All the grid connected hydro plants in Georgia and information on their operating history before those units were rehabilitated (wherever applicable) was used to determine the operating history of units before these are rehabilitated and so to determine what is the common practice of rehabilitation of hydro plants in Georgia. It was found that there were a few units that had never been rehabilitated. The result of information based on the operating history information:

- In all there were 24 units at 7 hydro plants in Georgia that were assessed for their operating history prior to rehabilitation to understand if the rehabilitation of Hydro Plants was a common practice in Georgia;
- It was found that several units were never rehabilitated: In all 14 of 24 units;
- Number of units that have been rehabilitated or are being rehabilitated: 10 of 24 units;
- The longest operating history of a unit with no rehabilitation 308,150 hours (and still working without rehabilitation);
- The shortest operating history of a unit that was rehabilitated: 220,150 hours (chosen as $DATE_{BaselineRetrofit}$).

The geographical scope for assessing the rehabilitation activity at hydro power plants has been restricted to Georgia only, as (A) there is sufficient information regarding operating history of hydro power plants in Georgia and (B) different neighboring countries have very different access to energy resources (e.g. both Azerbaijan and Russia are rich in oil and gas) and that would define the state/ national priority for undertaking hydro rehabilitation activity in neighboring countries differently, and finally (C) achieving access to information regarding rehabilitation of hydro power plants in the neighboring countries would have been extremely difficult and might not have been possible.

Further:

- In general, rehabilitation of hydro power plants to increase the efficiency and capacity of the hydro plants is not at all practiced in Georgia. Rehabilitation of hydro power plants is done only in case a unit had to be shut down due to any electrical and/or mechanical fault.

- Rehabilitation of hydro power plant of such magnitude – leading to an overall increase in the capacity of the project by >200MW and at units with a unit nameplate capacity of 260MW is not a common practice at all.

However, since hydro rehabilitation work is indeed undertaken in some of the units of hydro plants in Georgia. The next step of analysis (Sub-step 4b) is being conducted to absolutely establish that Enguri Hydro Power Plant Rehabilitation project is not a common practice.

Sub-step 4b: Discuss any similar options that are occurring:

The current operating age of all the Enguri Hydro Power Plant's Units is far below the operating life of other hydro units in Georgia where rehabilitation work was conducted:

- Operating history of Units of Enguri plant (ranging from 97,266 to 131,221), far below the chosen $DATE_{Baseline\,\mathrm{Re}trofit}$ = 220,150 hours (as given in table below and explained in detail in Section B.4.)
- That each of the four units (Unit # 2, 4, 1 and 5) were operating prior to rehabilitation.

	At the end of 2005	Lifetime before rehabilitation	Remaining Lifetime of Units (Hours) at end of 2005	Expected lifetime years	$DATE_{Baseline\,\mathrm{Re}trofit}$
Unit 1	97,266	220,150	122,881	24.6	2029.6
Unit 2	108,619	220,150	111,531	22.3	2027.3
Unit 4	111,251	220,150	108,899	21.8	2026.8
Unit 5	131,221	220,150	88,929	17.8	2022.8

Thus, rehabilitation of units of Enguri Hydro Power Plant:

- Faces several barriers that would prevent investment in the rehabilitation without CDM revenues
- And that rehabilitation of hydro units (unless there is a complete breakdown due to mechanical/electrical fault) not a common practice

Thus, it is demonstrated that rehabilitation work at hydro power plant's units, where the units are already operational, is not a common practice. And generally the hydro power plant units in Georgia have went on to operate for at least as long as 220,150 hours before needing any rehabilitation, which is almost two times the current operational lifetime of Enguri units (at the time of CDM decision making).

Hence, it is proven that rehabilitation of Hydro Power plants, when they are still in operation, and at an early operating life (Varying from 97,266 to 131,221 hours) is not a common practice in Georgia.

Hence, it is established that investment in the rehabilitation of units of Enguri Hydro power plant is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The following methodological choices (as laid out in Version 12.1.0 of ACM0002) will be applied to calculate Emission Reductions. The section below describes the relevant sections of ACM0002 that would apply to the current project activity. The equations numbers mentioned are from ACM0002 as would apply to the current project activity.

Project Emissions:

Per the Version 12.1.0 of CDM methodology ACM0002 – the project emissions are to be accounted for only those renewable energy projects that also entail: (a) fossil fuel consumption (b) geothermal power plants (c) hydro plants that lead to new reservoirs.

None of three mentioned criteria apply to the rehabilitation of Enguri hydro plant. Hence:

$PE_y = 0$ *(Equation 1)*

Where: PE_y *is project emissions in year y (tCO2e/yr)*

Baseline emissions:

Baseline emissions are calculated using the Equation 6 of the methodology:

$BE_y = EG_{PJ,y} * EF_{Grid,CM,y}$ *(Equation 6)*

Where:

Parameter	Explanation
BE_y	Baseline emissions in year y (tCO2e/MWh)
$EG_{PJ,y}$	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in the year y (MWh/yr)
$EF_{grid,CM,y}$	Combined margin CO2 emission factor for grid connected power generation in year *y* calculated using the latest version of the “Tool to calculate the emission factor for an electricity system” (tCO2/MWh)

Calculation of $\boldsymbol{EG_{PJ,y}}$**:**

As per the methodology the calculation of $\boldsymbol{EG_{PJ,y}}$ is different for (a) Greenfield plants, (b) retrofit and replacements, and (c) capacity additions.

In the case of the current CDM project activity, case (b) would apply:

(b) Retrofit of replacement of an existing renewable energy power plant:

If the project activity is the retrofit or replacement of an existing grid-connected renewable power plant, the baseline scenario is the continuation of the operation of the existing plant. The methodology uses historical electricity generation data to determine the electricity generation by the existing plant in the baseline scenario, assuming that the historical situation observed prior to the implementation of the project activity would continue.

The power generation of renewable energy projects can vary significantly from year to year, due to natural variations in the availability of the renewable source (e.g. varying rainfall, wind speed or solar radiation). The use of few historical years to establish the baseline electricity generation can therefore involve a significant uncertainty. The methodology addresses this uncertainty by adjusting the historical

electricity generation by its standard deviation. This ensures that the baseline electricity generation is established in a conservative manner and that the calculated emission reductions are attributable to the project activity. Without this adjustment, the calculated emission reductions could mainly depend on the natural variability observed during the historical period rather than the effects of the project activity.

This CDM rehabilitation project is a project activity that retrofits three generation units (Unit #2, Unit # 4, Unit # 1 and Unit # 5) of Enguri HPP. For such a project activity, the baseline emissions are the following:

Thus:

$EG_{PJ,y} = EG_{facility,y} - (EG_{historical} + \sigma_{historical})$; until $DATE_{BaselineRetrofit}$ (*Equation 8)*

And

$EG_{PJ,y} = 0$; on or after $DATE_{BaselineRetrofit}$ (*Equation 9)*

Where:

Parameter	**Explanation**
$EG_{PJ,y}$	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in the year y (MWh/yr)
$EG_{facility,y}$	Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y* (MWh/yr)
$EG_{historical}$	Annual average historical net electricity generation delivered to the grid by the existing renewable energy plant that was operated at the project site prior to the implementation of the project activity (MWh/yr)
$\sigma_{historical}$	Standard deviation of the annual average historical net electricity generation delivered to the grid by the existing renewable energy plant that was operated at the project site prior to the implementation of the project activity (MWh/yr)
$DATE_{BaselineRetrofit}$	Point in time when the existing equipment would need to be replaced in the absence of the project activity (date)

$EG_{historical}$ is the annual average of historical net electricity generation, delivered to the grid by the existing renewable energy plant that was operated at the project site prior to the implementation of the project activity. To determine $EG_{historical}$, project participants may choose between two historical periods. This allows some flexibility: the use of the longer time period may result in a lower standard deviation and the use of the shorter period may allow a better reflection of the (technical) circumstances observed during the more recent years.

Project participants may choose among the following two time spans of historical data to determine $EG_{historical}$:

(a) The five last calendar years prior to the implementation of the project activity; or

(b) The time period from the calendar year following $DATE_{hist}$, up to the last calendar year prior to the implementation of the project, as long as this time span includes at least five calendar years, where $DATE_{hist}$ is latest point in time between:

- (i) The commercial commissioning of the plant/unit;
- (ii) If applicable: the last capacity addition to the plant/unit; or

(iii) If applicable: the last retrofit of the plant/unit.

<u>For the current PDD – Option (a): The five last calendar years prior to the implementation of the project activity has been chosen to determine EGhistorical.</u>

As calculated above: $DATE_{Baseline\,Retrofit}$ is 31/12/2022; which is three years beyond the end of crediting period of the CDM project activity (the crediting period of the CDM project activity ends in September 30, 2021). Hence, only equation (8) would hold good for the calculation of $EG_{PJ,y}$

Detailed Calculation of $EF_{grid,CM,y}$ is given in Annex 2 of the CDM PDD. The grid emission factor for Georgia has been provided by the DNA of Georgia. This has been provided as $EF_{Grid,CM,y}$ = 0.3999tCO_{2eq}.

<u>Leakage emissions</u>

The methodology ACM0002 states that: "No leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction, processing, and transport). These emissions sources are neglected."

Therefore, as per methodology ACM0002 leakage emissions are to be considered zero for this project activity.

Emission Reductions:

As per methodology emission reductions (ER_y) are calculated as:

$$ER_y = BE_y - PE_y \qquad \textit{(Equation 11)}$$

Since, there are no project emissions associated with the project activity. The final equation for calculation of emission reduction is:

$$ER_y = BE_y = \left(EG_{facility,y} - \left(EG_{historical} + \sigma_{historical}\right)\right) * EF_{grid,CM,y}$$

Where:

Parameter	Explanation
ER_y	Emission reductions in the year y (tCO2e/MWh)

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	**Emission factor of the grid ($EF_{Grid,CM,y}$)**
Data unit:	tCO2e/MWh
Description:	The emission factor for the Georgian grid (combined emission factor) has been calculated as weighted average of the generation-weighted average of Simple Adjusted Operating margins for 2004, 2005 and 2006 and the Build margin as for methodology ACM0002. This is the latest available data from the Georgian Designated National

	Authority. The emission factor has been calculated ex-ante and fixed throughout the CDM crediting period.
Source of data used:	Georgian Designated National Authority (Ministry of Environmental Protection and Natural Resources) and the Ministry of Energy, Georgia. The "Baseline Emission Factor for the Electricity System of Georgia" is available at: www.moe.gov.ge/files/Klimatis%20Cvlileba/Grid_Emission_Factor_Georgia.pdf
Value applied:	0.3999
Justification of the choice of data or description of measurement methods and procedures actually applied :	The justification for using the simple adjusted operating margin and the methodological choices underlying the calculation of the operating and the build margin are detailed in Annex 3. Uncertainty regarding the underlying data used for the calculations is minimal, as official data from the Ministry of Energy and the Georgian Electricity Dispatch Centre were used.
Any comment:	The baseline emission factor of the electricity system of Georgia was prepared and calculated by Grigol Lazriev (Acting Head of the Hydrometeorology and Climate Change Division of the Department of International Relations and Conventions at the Ministry of Environment Protection and Natural Resources) and Marita Arabidze (Main Specialist of the Department of Energy Policy and International Relations, Ministry of Energy). This factor is highly recommended to all electricity-connected CDM projects in Georgia.

Data / Parameter:	$EG_{historical}$
Data unit:	GWh/yr
Description:	Average level of electricity supplied to the Georgian grid by Enguri HPP's *Unit #2, Unit #4, Unit #1 and Unit #5* in the years 2001 to 2005.
Source of data used:	The generation data has been provided by production data recording log of Engurhesi Ltd. Measurement of the energy generation is done through meters, which are calibrated regularly.
Value applied:	The average energy supply by each of the units is give below: 1. Unit # 1: 670.1GWh = $EG_{historical, unit 1}$ 2. Unit # 2: 637.2GWh = $EG_{historical, unit 2}$ 3. Unit # 4: 691.1GWh = $EG_{historical, unit 4}$ 4. Unit # 5: 757.8GWh = $EG_{historical, unit 5}$ Detailed Historical Generation Data for each of the four units is given below

Year	***2001***	***2002***	***2003***	***2004***	***2005***	***Average***
Unit 1 Electricity Produced (GWh)	536.8	449.0	566.5	861.9	936.5	670.1
Unit 2 Electricity Produced (GWh)	607.1	715.2	798.0	659.6	406.0	637.2
Unit 4 Electricity Produced (GWh)	409.3	819.7	930.2	612.8	683.6	691.1

	Unit 5 Electricity Produced (GWh)	793.8	1,005.2	772.2	665.0	552.9	757.8

Justification of the choice of data or description of measurement methods and procedures actually applied :	Project participants may choose among the following two time spans of historical data to determine $EG_{historical}$: **(a) The five last calendar years prior to the implementation of the project activity**; or (b) The time period from the calendar year following $DATE_{hist}$, up to the last calendar year prior to the implementation of the project, as long as this time span includes at least five calendar years, where $DATE_{hist}$ is latest point in time between: (i) The commercial commissioning of the plant/unit; (ii) If applicable: the last capacity addition to the plant/unit; or (iii) If applicable: the last retrofit of the plant/unit. Thus, as per the methodology – Option (a) above has been chosen.
Any comment:	$EG_{historical}$ is the sum of historical generation from each of the units of Enguri HPP. This has been added to $\sigma_{historical}$ of the respective unit to determine the requirements of equation (8) as per the Version 12.1.0 of ACM0002 methodology.

Data / Parameter:	$\sigma_{historical}$
Data unit:	GWh/yr
Description:	Standard deviation of the annual average historical net electricity generation delivered to the grid by the existing renewable energy plant that was operated at the project site prior to the implementation of the project activity
Source of data used:	Engurhesi Ltd – **Calculated** from the data used to establish $EG_{historical}$
Value applied:	The average energy supply by each of the units is given below: 1. Unit # 1: 215.1GWh = $\sigma_{historical, unit 1}$ 2. Unit # 2: 147.3GWh = $\sigma_{historical, unit 2}$ 3. Unit # 4: 199.6GWh = $\sigma_{historical, unit 4}$ 4. Unit # 5: 168.3GWh = $\sigma_{historical, unit 5}$
Justification of the choice of data or description of measurement methods and procedures actually applied :	This has been calculated for the same vintage and for the same set of data that was used to determine $EG_{historical}$

Any comment:	Total of $EG_{Historical}$ and $\sigma_{historical}$ for each of the five units is given in table below:

	$EG_{Historical}$ + $\sigma_{historical}$ Average + Std Dev
Unit 1 Electricity Produced (GWh)	885.2
Unit 2 Electricity Produced (GWh)	784.5
Unit 4 Electricity Produced (GWh)	890.7
Unit 5 Electricity Produced (GWh)	926.1
Average of four units	**871.6**

Data / Parameter:	$DATE_{Baseline\,Retrofit}$
Data unit:	Date
Description:	Point in time when the existing equipment would need to be replaced in the absence of the project activity.
Source of data used:	Survey of operation data of other hydro power plants in the region. The actual date is calculated based on the rehabilitation history information about 24 hydro units at 7 hydro plants in Georgia.
Value applied:	31/12/2022
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per the provisions of the methodology. Detailed description has been provided in Section B.4 of the PDD.
Any comment:	-

Data / Parameter:	***Cap_{BL}***
Data unit:	W
Description:	Installed capacity of the hydro power plant before the implementation of the project activity. For new hydro power plants, this value is zero
Source of data used:	'As observed/recorded as on 17 June 2005 by the Technical Director of Engurhesi Ltd. The Unit maximum operating capacity was determined by running the unit at maximum load (water flow) till the unit started to become unstable (higher than normal level of vibrations).
Value applied:	(see table below)

Maximum Output	**MW**
Unit 1 (MW)	210.0
Unit 2 (MW)	220.0
Unit 4 (MW)	210.0
Unit 5 (MW)	230.0

Justification of the choice of data or description of measurement methods and procedures	The installed operating capacity of each of the units has been determined based on the accepted procedures and standards by Engurhesi Ltd.

actually applied :	
Any comment:	However, the Cap_{BL} was not possible to achieve at all the time when the units were in operation (or are in operation) prior to rehabilitation. The average operational capacity that was possible to achieve over the operation years (1993-2005) is given in the figure below: **Average Output (1993-2005)** | **MW** Unit 1 (MW) | 157.5 Unit 2 (MW) | 156.1 Unit 4 (MW) | 155.9 Unit 5 (MW) | 144.3

Data / Parameter:	$DATE_{hist}$
Data unit:	Date
Description:	Point in time from which the time span of historical data for retrofit or replacement project activities may start However, for calculation of $EG_{Historical}$ the latest five year data (from 2001 to 2005) has been used to estimate $EG_{Historical}$
Source of data used:	Engurhesi Ltd – Units operation data
Value applied:	1. Unit # 1: 01/01/1979 (Though the unit was commissioned in 1978 – 1979 was the first full year of operation and hence data from 1979 has been considered) 2. Unit # 2: 01/01/1979 (Though the unit was commissioned in 1978 – 1979 was the first full year of operation and hence data from 1979 has been considered) 3. Unit # 4: 01/01/1980 (Though the unit was commissioned in 1979 – 1980 was the first full year of operation and hence data from 1980 has been considered) 4. Unit # 5: 01/01/1981 (Though the unit was commissioned in 1979 – 1981 was the first full year of operation and hence data from 1981 has been considered) Thus, $EG_{Historical}$ for each of the four units is 01/01/2000 and generation data from each of these units from 01/01/2000 t0 31/12/2005 has been used to estimate the value of $EG_{Historical.}$ $DATE_{Hist}$ is not used for the calculation of emission reductions.
Justification of the choice of data or description of measurement methods and procedures actually applied :	$DATE_{hist}$ is the latest point in time between: (i) The commercial commissioning of the plant/unit; This has been applied as neither (ii – the last capacity addition to plant/unit) nor (iii – the last retrofit of the plant) will be applicable in the context of Enguri Hydro project
Any comment:	However, for calculation of $EG_{Historical}$ the latest five year data (from 2001 to 2005) has been used to estimate $EG_{Historical}$

Data / Parameter:	**Total Additional Power Generation ($EG_{PJ,y}$)**
Data unit:	MWh
Description:	This is additional quantity of electricity generation achieved through the project scenario, compared to the baseline scenario. It is derived by calculating the difference between $EG_{facility,y}$, and ($EG_{historical}$ + $\sigma_{historical}$)
Source of data used:	The data used to calculate this parameter were provided by Engurhesi Ltd, particularly: • $EG_{historical}$ was calculated using the unit generation information available from 2001-2005 (five year data). The generation data has been provided by production data recording log of Engurhesi Ltd. Measurement of the energy generation is done through meters, which are calibrated regularly; • $\sigma_{historical}$ was calculated from the data used to establish $EG_{historical}$ • $EG_{facility,y}$ was estimated based on the expected capacity and plant load factor due to the project implementation.
Value applied:	Values of $EG_{PJ,y}$ applied are provided in the table below: (see tables below) They are are also given in Section B.6.3 (page 44).
Justification of the choice of data or description of measurement methods and procedures actually applied :	This parameter has been calculated as per Equation 8 of the ACM002. The choice of data is justified as follows: • For $EG_{historical}$ project proponent has chosen Option (a) - the five last calendar years prior to the implementation of the project activity - for the time span of historical data, as allowed by the methodology; • $\sigma_{historical}$ has been calculated for the same vintage and for the same set of data that was used to determine $EG_{historical}$. • For the purpose of ex-ante calculations, $EG_{facility,y}$ was estimated, assuming that each unit will operate at their maximum indicated capacity of 270MW and at the plant load factor of 57.08%. Detailed calculation steps of $EG_{PJ,y}$ are provided in the Section B.6.3., and in the CER calculation spreadsheet submitted to the DOE.
Any comment:	-

Year	2011	2012	2013	2014	2015
Project Generation (GWh), Unit 1	N/A	348.6	464.8	464.8	464.8
Project Generation (GWh), Unit 2	565.5	565.5	565.5	565.5	565.5
Project Generation (GWh), Unit 4	459.3	459.3	459.3	459.3	459.3
Project Generation (GWh), Unit 5	N/A	N/A	317.9	423.9	423.9
Total Additional Power Generation (GWh)	1,024.8	1,373.4	1,807.5	1,913.5	1,913.5
Total Additional Power Generation (MWh)	**1,024,825**	**1,373,393**	**1,807,501**	**1,913,475**	**1,913,475**

Year	2016	2017	2018	2019	2020	2021
Project Generation (GWh), Unit 1	464.8	464.8	464.8	464.8	464.8	464.8
Project Generation (GWh), Unit 2	565.5	565.5	565.5	565.5	565.5	565.5
Project Generation (GWh), Unit 4	459.3	459.3	459.3	459.3	459.3	459.3
Project Generation (GWh), Unit 5	423.9	423.9	423.9	423.9	423.9	423.9
Total Additional Power Generation (GWh)	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5
Total Additional Power Generation (MWh)	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**

B.6.3 Ex-ante calculation of emission reductions:

The methodological choices as explained in Section B.6.1 would be applied below to determine the ex-ante estimation of emission reductions:

Project Emissions:

As described in Section B.6.1 – there are no project emissions for the current project activity.

$PE_y = 0$ *(Equation 1)*

Baseline emissions:

Baseline emissions are calculated using the Equation 6 of the methodology:

$$BE_y = EG_{PJ,y} * EF_{Grid,CM,y} \quad \textit{(Equation 6)}$$

$EF_{Grid,CM,y}$ = *0.3999tCO2e/MWh* as explained in Annex 3 of the PDD. As per the 'Tool to estimate the emission factor of an electricity system' – the grid emission factor has been kept fixed for the entire crediting period.

Using Equation 8 we now calculate $EG_{PJ,y}$. Following steps are involved:
Step 1: Calculate $EG_{historical}$ and $\sigma_{historical}$ using the unit generation information available from 2001-2005 (five year data)
Step 2: Estimate $EG_{facility,y}$ based on the expected increase in installed capacity and plant load factor

Step 1: Calculate $EG_{Historical}$ and $\sigma_{Historical}$ using the unit generation information available from 2001-2005 (five year data)

Year	2001	2002	2003	2004	2005	Average	STD DEV	EG Hist + SD	Period
Unit 1 Electricity Produced (GWh)	536.8	449.0	566.5	861.9	936.5	670.1	215.1	885.2	2001-2005
Unit 2 Electricity Produced (GWh)	607.1	715.2	798.0	659.6	406.0	637.2	147.3	784.5	2001-2005
Unit 4 Electricity Produced (GWh)	409.3	819.7	930.2	612.8	683.6	691.1	199.6	890.7	2001-2005
Unit 5 Electricity Produced (GWh)	793.8	1,005.2	772.2	665.0	552.9	757.8	168.3	926.1	2001-2005
Total Units 1,2,4,5 Electricity Produced (GWh)	**2,347.1**	**2,989.0**	**3,066.9**	**2,799.2**	**2,578.9**	**689.1**	**182.6**	**871.6**	

	Average+Std Dev	Implementation Schedule
Unit 1 Electricity Produced (GWh)	885.2	*Expected implementation by March 2012*
Unit 2 Electricity Produced (GWh)	784.5	Implementation complete in March 2008
Unit 4 Electricity Produced (GWh)	890.7	Implementation complete in March 2009
Unit 5 Electricity Produced (GWh)	926.1	*Expected implementation by March 2013*
Average of four units	**871.6**	

Data Source: Engurhesi balance accounts

Step 2: Estimate $EG_{facility,y}$ based on the expected increase in installed capacity and plant load factor

After the implementation of the project activity the units would be able to operate at their maximum indicated capacity of 270MW throughout the operation life.
The expected plant load factor after the units become operational has been estimated at 57.08%
Thus, in any full year of operation each of the units at the given installed capacity of 270MW running at 5,000 hours will generate 1,350GWh of electricity.

Additional Information about Historical Generation:

Historically the units have had a maximum generation capacity as given in the table below. However, due to design faults (from ever since the installation of these units. The full installed capacity has never been realized and the units have been operating at an average capacity much lower (as given in table below) than the maximum observable capacity (for short runs as given in the table below).

Maximum Achievable Output from Units	**Average Observable Output from Units**

Maximum Output	MW
Unit 1 (MW)	210.0
Unit 2 (MW)	220.0
Unit 4 (MW)	210.0
Unit 5 (MW)	230.0

Source: *As observed/recorded as on 17 June 2005 by the Technical Director of Engurhesi Ltd*

Average Output (1993-2005)	MW
Unit 1 (MW)	157.5
Unit 2 (MW)	156.1
Unit 4 (MW)	155.9
Unit 5 (MW)	144.3

Source: As authenticated by the engineers from Stucky Ltd.

Ex-ante emission reduction calculation :

Having calculated the historical generation ($EG_{Historical}$) as required by the methodology, and the ex-ante estimate of the project generation after rehabilitation of the units, in the following section the ex-ante estimate of emission reduction is being made. The following assumptions have also been made:

- The start date of crediting period has been taken as October 1, 2011. And the crediting period runs till December 31, 2021.
- Expected implementation of Unit # 1 by March 2012 (Emission reductions have been calculated from April 2012)
- Expected implementation of Unit # 5 by March 2013 (Emission reductions have been calculated from April 2013)
- The expected generation by each of the units after rehabilitation has been considered as 1,350GWh based on annual plant load factor of 57.08% and an installed capacity of 270MW.
- The emission factor for the Georgian grid has been fixed ex-ante (based on the information provided by the DNA of Georgia): 0.3999 tCO_{2eq}/MWh

The following table provides information about Baseline scenario (historical generation). This is sum of $EG_{Historical}$ and $\sigma_{Historical}$:

Baseline Scenario (Baseline Generation)											
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Baseline Generation (GWh), Unit 1	N/A	663.9	885.2	885.2	885.2	885.2	885.2	885.2	885.2	885.2	885.2
Baseline Generation (GWh), Unit 2	784.5	784.5	784.5	784.5	784.5	784.5	784.5	784.5	784.5	784.5	784.5
Baseline Generation (GWh), Unit 4	890.7	890.7	890.7	890.7	890.7	890.7	890.7	890.7	890.7	890.7	890.7
Baseline Generation (GWh), Unit 5	N/A	N/A	694.6	926.1	926.1	926.1	926.1	926.1	926.1	926.1	926.1

The following table provides information about Project scenario (expected generation):

Project Scenario (Project Generation)											
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Project Generation (GWh), Unit 1	N/A	1,012.5	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0
Project Generation (GWh), Unit 2	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0
Project Generation (GWh), Unit 4	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0
Project Generation (GWh), Unit 5	N/A	N/A	1,012.5	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0	1,350.0

The following table provides information about <u>additional</u> power generation in project scenario vis-à-vis baseline scenario (Equation 8):
Also as per Equation no 8 of ACM0002 (Version 12.1.0) and as indicated in Section B.6.1:
$EG_{PJ,y} = EG_{facility,y} - \left(EG_{historical} + \sigma_{historical}\right)$; until $DATE_{BaselineRetrofit}$ (As given in the last row in the table below)

Additional Power Generation (Project)											
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Project Generation (GWh), Unit 1	N/A	348.6	464.8	464.8	464.8	464.8	464.8	464.8	464.8	464.8	464.8
Project Generation (GWh), Unit 2	565.5	565.5	565.5	565.5	565.5	565.5	565.5	565.5	565.5	565.5	565.5
Project Generation (GWh), Unit 4	459.3	459.3	459.3	459.3	459.3	459.3	459.3	459.3	459.3	459.3	459.3
Project Generation (GWh), Unit 5	N/A	N/A	317.9	423.9	423.9	423.9	423.9	423.9	423.9	423.9	423.9
Total Additional Power Generation (GV	1,024.8	1,373.4	1,807.5	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5	1,913.5
Total Additional Power Generation (I	**1,024,825**	**1,373,393**	**1,807,501**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**	**1,913,475**

Baseline Emissions (Equation 06):

Baseline emissions are calculated using the Equation 6 of the methodology:

$BE_y = EG_{PJ,y} * EF_{Grid,CM,y}$ *(Equation 6)*

Baseline Emissions											
Years into crediting period	0.25	1.25	2.25	3.25	4.25	5.25	6.25	7.25	8.25	9.25	10.00
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Total Additional Power Generation (MWh)	1,024,825	1,373,393	1,807,501	1,913,475	1,913,475	1,913,475	1,913,475	1,913,475	1,913,475	1,913,475	1,913,475
Emission Factor of Georgian Grid (tCO2/MWh)	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999	0.3999
Baseline Emissions (tCO2e)	**102,457**	**549,220**	**722,820**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**573,899**

In the first year 2011, the emission reductions are lower as only ($1/4^{th}$ of expected for the full calendar year) as the project is expected to be registered with the CDM UNFCCC EB only by September 30, 2011, likewise in the last year 2021, the emission reductions are lower as only ($3/4^{th}$ of expected for the full calendar year) as the project activity's 10 year crediting period will come to an end on September 30, 2021.

Emission Reduction (Ex-ante estimate using Equation 11):

$ER_y = BE_y - PE_y$; **As $PE_y = 0$;** $ER_y = BE_y = \left(EG_{facility,y} - \left(EG_{historical} + \sigma_{historical}\right)\right) * EF_{grid,CM,y}$ → As given in the table below:

Emission Reductions (tCO2e)											
Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Emission Reductions (tCO2e)	**102,457**	**549,220**	**722,820**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**765,198**	**573,899**

B.6.4 Summary of the ex-ante estimation of emission reductions:

The following is a final table detailing the overall emissions reductions of the project activity**:**

Years	**Estimation of Project Emissions in tCO_{2eq}**	**Estimation of Baseline Emissions in tCO_{2eq}**	**Estimation of leakage in tCO_{2eq}**	**Estimation of overall Emissions Reductions in tCO_{2eq}**
October 2011- December 2011	0	102,457	0	102,457
January 2012- December 2012	0	549,220	0	549,220
January 2013- December 2013	0	722,820	0	722,820
January 2014- December 2014	0	765,198	0	765,198
January 2015- December 2015	0	765,198	0	765,198
January 2016- December 2016	0	765,198	0	765,198
January 2017- December 2017	0	765,198	0	765,198
January 2018- December 2018	0	765,198	0	765,198
January 2019- December 2019	0	765,198	0	765,198
January 2020- December 2020	0	765,198	0	765,198
January 2021 – September 2021	0	573,889	0	573,889
Total (tCO2e)	0	**7,304,785**	0	**7,304,785**
Average (tCO2e)	0	**730,478**	0	**730,478**

Total number of crediting years	**10**

B.7 Application of the monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

Data / Parameter:	$EG_{facility,y}$
Data unit:	GWh
Description:	**Electricity supplied annually to the grid by Enguri HPP** Since, different units will be rehabilitated and commissioned separately $EG_{facility,y}$ has to be calculated for each of the units and subsequently be applied separately for each of the units too. Though, since each of the unit is going to be rehabilitated to the same standard $EG_{facility,y}$ is same for each of the unit.
Source of data to be used:	Electricity meter on each of the units at Enguri HPP. The data for $EG_{facility,y}$ will be presented net of any electricity imported from the grid for start-ups etc. a. Each Unit (generator) has its own electronic power-meter which is incorporated in the Unit Control System and records (electronically) power generation for each unit.

	b. Also there are separately mounted power-meters which again record power generation per each unit and which are used (and sealed) by the transmission company for measuring total generation of the plant. c. And finally, at the point of connection between the plant's switchyard and Central Transmission Line there is final power-meter used (and sealed) by the transmission company for the invoicing purposes. Difference between 2 and 3 is "Own Consumption of the Plant" which is not invoiced because it is internally consumed, but is still recorded as generation. The readings of meter 'c' for each of the units would be used for CDM purpose.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	The energy supplies by each of the units after rehabilitation is give below: 1. Unit # 1: 1,350GWh = $EG_{facility,\ unit\ 1}$ 2. Unit # 2: 1,350GWh = $EG_{facility,\ unit\ 2}$ 3. Unit # 4: 1,350GWh = $EG_{facility,\ unit\ 4}$ 4. Unit # 5: 1,350GWh = $EG_{facility,\ unit\ 5}$
Description of measurement methods and procedures to be applied:	At the time of monitoring and verification the data from the energy meter at each of the units (that are part of the CDM project activity after having been rehabilitated) would be taken and any electricity imported in the period will be subtracted from this to give the net electricity exported to the grid, i.e. $EG_{facility,y}$. Measurements will be taken every eight hours by a representative of Engurhesi Ltd from an electricity meter fitted to the unit. The meters are continuous recording electricity transfer as the electricity is exported. However, the daily recording of electricity export is conducted only three times (This is a general practice by maximum utilities in the world). The uncertainty of this measurement depends on the calibration of the meter. Annual check and certification (calibration) process is performed jointly by the State Electric System and the Commercial Operator of the Georgian Electricity Network and will ensure that that uncertainty level of the measurements carried out by the meter is within the range allowed by international standards and Georgian law.
QA/QC procedures to be applied:	Quality assurance of the metering devices is ensured by the mandatory annual calibration process performed by the State Electric System and the Commercial Operator. This ensures the accuracy of the metering devices. To ensure that metering equipment cannot be tampered with it is initially certified by the State Standardization Organization and is checked on a regular basis by three parties: State Electric System, Commercial Operator of the National Electricity Network and Engurhesi Ltd. The meters are stamped by all parties and they cannot be opened or manipulated by any single party. The records of electricity generated for each Enguri Unit that are taken by Engurhesi Ltd are verified against an alternative source of information, which

	are the records taken by network administrator. Official representatives of State Electric System and Commercial Operator of the National Electricity Network check Enguri's readings for each unit on a quarterly basis and compare them with their own records of dispatched electricity to the central network. Cross check measurement results with records for sold electricity
Any comment:	Unit #2 has started to generate power from March 2008 Unit #4 is generating electricity from August 2009 Unit # 1 is expected to being generate electricity from March 2012 Unit #5 is expected to begin generate electricity from March 2013

B.7.2 Description of the monitoring plan:

As stated by the latest version of the monitoring methodology "ACM0002 Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources", The monitoring of the following is required: "Electricity generation from the proposed project activity". The other data listed in the methodology should not be monitored for this CDM project activity since the ex-ante method was applied for the calculation of the build margin and the operating margin and since this project is not a new hydro electric power project.

This monitoring plan is developed in a project specific manner specifically addressing the unique features of the Enguri HPP and the specifics of electricity metering and meters verification currently in practice in Georgia.

The spatial extent of the monitoring plan will be the physical project site of the CDM project activity that corresponds to the Unit # 2, Unit #4, Unit # 1 and Unit # 5.
Once implemented, the relevant data monitoring report will be submitted to a designated operational entity contracted to verify the emission reductions achieved during the crediting period. Any revisions requiring improved accuracy and/or completeness of information will be justified and will be submitted to a designated operational entity for validation.

Meters positioning

Meters are installed at the Control Panels of each generator of the Enguri HPP (i.e. one meter for each Unit of the Enguri HPP). In addition, there are voltage transformers which feed the meters (so called Vat-meters of the feeder-transformers). Vat-meters are also installed for each Unit. Proper installation of the meters is ensured by the inspection organisations (see below).

Responsibility, authority and procedure for meter readings

The operational responsibility for taking electricity meter readings on generator units and dispatched electricity lies within a team of ten workers (chief operators, chief technicians) who are currently in charge of taking meter readings. The overall authority of meter readings lies with Mr. Levan Mebonia, general manager of Engurhesi Ltd. The ten technicians ultimately report to Mr. Levan Mebonia, general manager of Engurhesi Ltd.

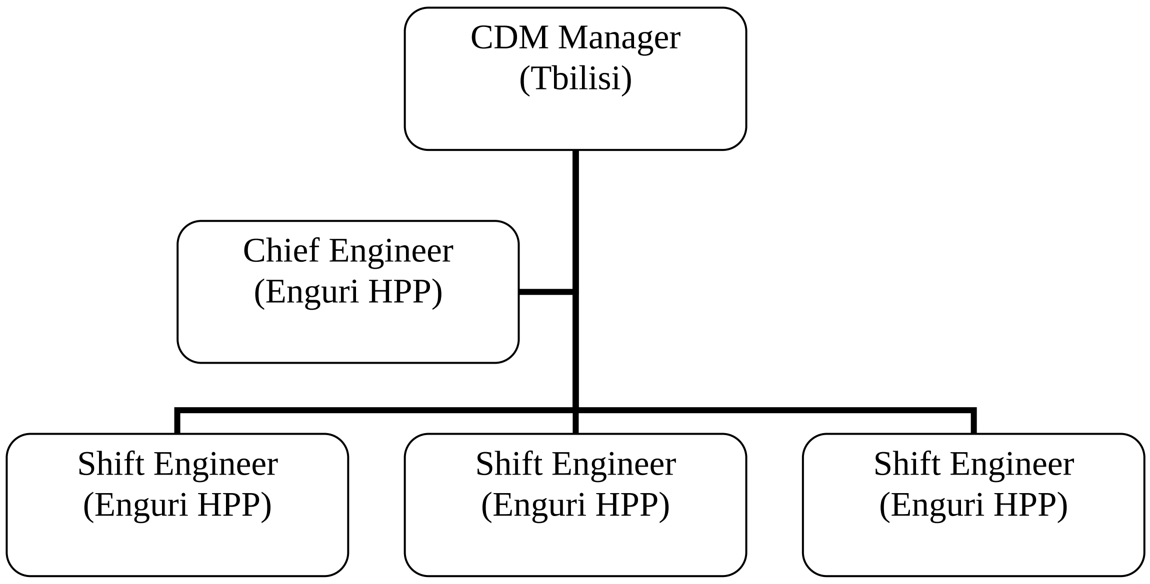
The reporting procedure is as follows: every 8 hours (there are regular three shifts the operating personnel at the plant) the chief operator reads the meter and reports to the Commercial Operator of the National Electricity Network. The reading is also recorded in the plant journal.

Operational and Management Structure:

With the view of monitoring emission reductions from the CDM project Engurhesi has in place (and will duly maintain) the following Operational and Management structure:

The day to day data collection is completed by shift engineer at the Enguri plant. The recording of power generated at each unit is conducted every 8 hours. The information is recorded on both paper and electronically. This information will be stored as part of CDM project activity for a period of at least two years over and above the crediting period of the CDM project. Further, every month at the time of financial settlement of Engurhesi by transmission company – the copes of invoices will be stored (both paper and electronically after scanning) for a period of at least two years over and above the crediting period of the CDM project activity.

The managerial hierarchy for CDM project operation and management of Engurhesi plant and its reporting to the head office in Tbilisi is given below:



No names in the above operational structure have been indicated as different people are likely to assume above mentioned roles during the course of the CDM project activity.

The outlined operation and management structure for the Enguri HPP will ensure:

(i) Smooth data collection for the CDM project activity
(ii) Timely calibration of the monitoring equipment
(iii) Enduring data collection and data archiving for CDM project activity.

Quality Assurance and Quality Control

Quality assurance of the metering devices is ensured by the mandatory annual calibration process performed by the State Electric System and the Commercial Operator of the National Electricity Network. This ensures the accuracy of the metering devices.

Before 1998 the state agency in charge of verification of electricity produced and metering was the Georgian Central Energy Agency. This agency had a metrology department which was in charge of metering, verification and calibration of meters. In particular, the Agency had its own seal and the meters were sealed to limit unauthorized access. Each year the metrology department calibrated the meters and issued a calibration certificate.
The Vat-meters of the feeder-transformers were also classified and annually calibrated by the metrology department.
The annual verification and calibration acts are available at Enguri HPP.

After the State Central Energy Agency was abolished in 1998, two organizations became in charge of metering and verification: the Commercial Operator of the National Grid (which recently substituted the Georgian Wholesale Electricity Market) and Georgian State Electric System. The meters are now sealed by both organizations and check up and verification are carried out annually. The annual verification and calibration acts are available at Enguri HPP.

To ensure that metering equipment cannot be tampered with, the equipment is initially certified by the State Standardization Organization and is checked on a regular basis by three parties: State Electric System, Commercial Operator of the National Electricity Network and Engurhesi Ltd. The meters are stamped by all parties and they cannot be opened or manipulated by any single party.

Actual hourly generation by each source of power contributing to the Georgian grid is recorded by the network administrators. This allows for the records of electricity generated that are taken by Enguri Ltd to be verified against an alternative source. Also, official representatives of State Electric System and Commercial Operator of the National Electricity Network check Enguri's readings on a quarterly basis and compare them with their own records of dispatched electricity to the central network.

Internal audit and maintenance of monitoring equipment:

A standard procedure for minimizing the risk of damage on the meters exists at Enguri HPP.
Every 8 hours the chief operator reads the meter and reports the data to the Commercial Operator of the National Electricity Network. Since the load on each generator is well-known to the Commercial Operator of the National Electricity Network, as soon as the reading is recorded an anomaly is easily detectable by the Commercial Operator of the National Electricity Network. The Commercial Operator of the National Electricity Network will proceed to inspection as soon as the anomaly is detected. The irregularity will also be observed by the chief operators at Enguri HPP. The Enguri HPP can also request an inspection from the Commercial Operator of the National Electricity Network or the Georgian State Electric System. As a standard, the inspection takes place no more than after two days after the anomaly was recorded. Engurhesi's experience shows that inspections occur the next day after the irregularity is detected. On the site, one of the two organizations in charge of inspection, will report to Enguri HPP which measures need to be taken to manage the damage to the meters. Meters are re-calibrated after the inspection.

The internal audit of incorrect readings is implemented at Enguri HPP as follows. Incorrect readings can occur due to damages to the meter equipment or data recording mistakes. Incorrect readings are detected because two meters are installed for each generator: the main meter at the control panel and the Vat-meter. Incorrect readings of the meter are adjusted (corrected) by the readings on the Vat-meter of the feeder-transformers, so that there is no possibility of missing any readings.

Finally, the monitoring plan reflects the current good practices appropriate for the type of project activity. Firstly, contemporary high-tech international brand meters are used. Secondly standard meter inspection procedures apply for Enguri hydro plant, which entails at least two annual inspection and checks of the meters by two independent state bodies, the State Electric System and ESCO (Commercial Operator of the Grid). This is being done to ensure the consistency and integrity of the monitoring meters.

B.8 Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies)

The final baseline for the proposed CDM activity was completed on 21/06/2011 by:

ICF International (Carbon Advisor/Consultant)
3rd Floor, Kean House,
6 Kean Street, London WC2B 4AS, Great Britain
London WC2A 3LZ
Tel. +44 (0) 20 70923000
Fax +44 (0) 20 70923001
E-mail: Nina (nkaczmarczyk@icfi.com)

ICF International is not a project participant.

SECTION C. Duration of the project activity / crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

13/01/2006

This is the date when the contractor came back to the site and resumed the implementation of the rehabilitation work (after it ceased on 12 December 2005, and was resumed after the consideration of CDM benefits and implementation of security measures).

C.1.2. Expected operational lifetime of the project activity:

From the time of completion of the baseline study on June 21, 2011. The expected operational lifetime of the project activity is (rounded to closest month) : **11 years and 06 months**.

That is the lifetime of the project is expected till 31/12/2022

C.2 Choice of the crediting period and related information:

C.2.1. Renewable crediting period

C.2.1.1. Starting date of the first crediting period:

Not applicable

C.2.1.2. Length of the first crediting period:

Not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/10/2011

C.2.2.2. Length:

10 years and 00 months

SECTION D. Environmental impacts

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

A clear distinction should be made between the environmental impacts that the construction and commissioning of the Enguri dam and hydro power plant caused and continue to cause and the environmental risks associated with the operation of the plant which will be possible to eliminate or minimise through the rehabilitation of the plant. The rehabilitation of Enguri will not increase the environmental impacts created by the construction and commissioning of the dam. It will, however, enlarge the environmental benefits that Enguri brings by increasing the emissions-free electricity that the plant is able to generate.

Environmental Impact of Construction and Commissioning

The environmental impacts that the construction and commissioning of the Enguri dam and hydro power plant caused and continue to cause are significant and will continue regardless of rehabilitation. These impacts consist of:

- Interrupting the river and potential migration routes of fish
- Change from river to lake conditions

- Loss of approximately 10 km2 of vegetation, mainly forest, during first filling of the reservoir
- Change of the river Enguri discharge downstream of the dam (reduction of flow)
- Change of groundwater conditions in the Enguri floodplain
- Change in sediment load downstream of the dam, with potential effects on the estuary of the river and the nearby Black Sea Coast
- Change of downstream conditions in the river Eristckali and Okumi
- Loss of livelihood of 365 families which have had to be resettled.

Environmental Impact of Rehabilitation

The *Feasibility Study of Rehabilitation Final Report Part II: Environmental Health and Safety Audit*, was produced in February 1998, (which is made available to the Designated Operational Entity) by the European consortium of Electrowatt Engineering Ltd and Stucky SA (Switzerland) as part of the project feasibility study in 1997-98. This Audit reviewed the state of the plant and identified a number of respects in which the Enguri dam and power plant and ancillary installations are either damaging or risk damaging the environment. It also made suggestions for measures that could be taken to eliminate or minimise these risks. The table below summarises the risks and actions described.

Impact / Risk	Remediation/Mitigation Action
Negative visual impact of cranes, cableways and concrete plants abandoned after dam construction	Remove and dispose of properly
Contamination of river and surrounding soil through oil leakages	Inspections of all oil containing structures and appropriate repairs or replacements made. Investigations into possible waste disposal options as waste oil is presently stored on site. Install oil skimmers at the lorry parking area and mechanical workshop.
Acids in water treatment plant	Improve storage and handling of acids
Asbestos	Removal of asbestos in insulation and the store room, at least where damaged, and its replacement with alternative products
Technical waste water	Collection, installation of oil skimmers where necessary, treatment
Domestic waste water	Control / replacement of sewage system, treatment
Solid waste, materials and debris from the power plant	Remove, recycle or dispose of properly
Solid waste from settlement	Collect, dispose of properly

The outline of Enguri Rehabilitation Project including the *Environmental Health and Safety Audit* was duly submitted to the Environmental Ministry of Georgia before its approval by the Parliament of Georgia in 1998. However, no environmental permits were requested for the project because of it is a rehabilitation project and not a new construction.

Given the delays in the financing and implementation of the Enguri Rehabilitation project, an Environmental Action Plan was prepared only in 2006. The Project Implementation Unit of the Enguri

Rehabilitation Project prepared a detailed *Project Overview and the Report on Environmental Action Plan* in September 2006. The Environmental Action Plan is based on specifications of the International Hydropower Association as well as the World Bank Environmental Assessment and the EU environmental standards, and responds to four broad objectives: 1) Reducing consumption of resources, 2) Reducing the impact on nature, 3) Reducing the carbon intensity of energy production, and 4) Increasing product of service values. In addition, the Environmental Action Plan has taken into consideration the following Environmental and Health & Safety regulating laws of Georgia:

- Laws of Georgia on “Environmental Protection Permits” of 15 October 1996, and “State Ecological Examination” of 15 October 1996, in reference with construction and rehabilitation of Power Plants, Dams and Reservoirs, Hydro-technical Facilities;
- Law of Georgia on “Environmental Protection” of 10 December 1996, in reference with Environmental Audit and Licensing;
- Laws of Georgia on “Healthcare” of 10 December 1997, and “Security of Hazardous Enterprises” of 10 December 1997, in reference with the liability of employers towards the employees for informational provision of and care on professional deceases;
- Law of Georgia on “Management and protection of River banks” of 27 October 2000, in terms of Erosion protection and bank formation;
- Law of Georgia on “Employment” of 28 September 2001, in terms of provision of fair and safe working conditions for the employees;
- Law of Georgia on “Licensing of Geological Activities” of 8 May 2003, in terms of Geophysical, hydro-geological, geo-engineering and geo-ecological activities.

The *Environmental Action Plan* describes the remediation/mitigation actions that have been taken and are planned under two phases of the rehabilitation project as of September 2006. These are summarised in the table below:

Issue	Implementation status	Planned remedial action
Visual impact	All abandoned cranes, cableways and still structure of the concrete plant were removed.	The former concrete plant near the dam to be demolished
Oil containers of transformers Used oil tanks and oil skimmers Oil-contaminated water	Under the existing scope of the contract on Electro-Mechanical Works with Voith-Siemens all oil immersed transformers located in the underground power house were replaced by the dry (cast resin) type of new transformers. As a general rule, secondary (used) oil is treated in the regeneration plant for refining and reuse. At this stage no old oil tanks and skimmers are in use. Waste oil is kept in the oil tanks.	To protect drainage water from contamination both before and after rehabilitation, it is of highest priority that the company acquires the oil collection cubicle which shall be placed in the lower level drainage pit; Oil tanks and containers: inspect and define measures needed accordingly; Filling station: inspect underground diesel and petrol tanks and define any measures accordingly; As a high priority measure, the mechanical workshop needs to be equipped with oil channeling rout and the skimmer, and floor needs to be concrete-sealed.

Issue	Implementation status	Planned remedial action
Acids (Power House)	No acid source of contamination was detected during the inspection.	
Asbestos (Power House)	Insulation asbestos of Units # 3 and #2 cooling water piping were fully replaced. Buildings and workshops were checked for applied asbestos. No open exposure of such material was detected.	Supply and install neutralization equipment; Insulation asbestos of Unit #1 will be replaced during the rehabilitation of process in 2007. Replacing of all water cooling systems on remaining two un-rehabilitated units are planned to be carried out in the Phase II electro-mechanical works.
Waste (Power House and Dam)	All levels of the Plant and the Dam were substantially cleared. Steel and other remnants of old devices from the workshops and maintenance areas have been removed. Old switch-boards, transformers and cubicles of rehabilitated Unites # and 2 have been removed.	Provide waste water treatment plant for residential areas.
Contaminated soil (Power House)	No contamination of soil was detected during the inspection period.	

Trans-boundary impacts

Trans-boundary impacts were caused by the initial construction of the Enguri HPP and are not caused by the rehabilitation project. The Environmental Action Plan prepared in 2006 has listed known large scale impacts due to construction of the plant, such as: interrupting the river and potential migration routes for fish; Change from river to lake conditions; Loss of approximately 10 km2 of vegetation, mainly forest, during first filling of the reservoir, mainly forest, during first filling of the reservoir etc. However, these impacts are not caused by the rehabilitation project.

D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

The Parliament of Georgia gave its approval in 1998 of the Enguri Rehabilitation Project including the *Environmental Health and Safety Audit* conducted in 1997-1998..Reporting on the Environmental Action Plan was done annually. In 2007, Engurhesi Ltd received a letter from the Ministry of Environmental Protection stating that the environmental impacts of the rehabilitation project yet to be undertaken are not considered significant because of the rehabilitative nature of the project and a full environmental impact assessment is not required.

SECTION E. Stakeholders’ comments

E.1. Brief description how comments by local stakeholders have been invited and compiled:

A Stakeholder Consultation meeting was organised specifically for the “Refurbishment of Enguri Hydro Power Plant, Georgia” CDM project activity. Invitations to the Stakeholder Consultation were sent by letter, e-mail or communicated telephonically to 47 potential participants identified among stakeholders that are either impacted by this CDM project or have a direct interest in the CDM project.

The Stakeholder Consultation was held on Monday 12 March 2007, at 14.00 at the Meeting Hall “Salkhino”, Metekhi Sheraton Palace Hotel, 20 Telavi street, Tbilisi, 0103, Georgia. The meeting was conducted both in Georgian and English and simultaneous translation was provided. All attendees received a copy of the draft Project Design Document (version of January 2007 in English) and a questionnaire (in Georgian).
Two presenters gave PowerPoint presentations during the meeting as follows:

- 14.00 Presentation by Natalia Gorina, Senior Consultant, ICF International
    - Background on Clean Development Mechanism in Georgia
- 14.30 Presentation by Brendan Quigley, Project Manager for Consortium of International Engineering Consultants for the Enguri Project
    - Current status of implementation of the rehabilitation project
    - Environmental Action Plan at Enguri HPP
- 15.00 Presentation by Natalia Gorina, Senior Consultant, ICF International
    - Enguri HPP CDM project: purpose, project description, sustainable development benefits

The presentations were followed by a Question and Answer session.

The following is the list of attendees:

	Name	Surname	Organisation	Position
1	Giorgi	Abulashvili	Energy Efficiency Centre Georgia	Director
2	Alexander	Akhvlediani	Samegrelo-Zemo Svaneti Administration	Deputy Head of Administration
3	Ramin	Bakhturidze	Enguri Hydropower Station	Member of Supervisory Board
4	Nino	Chkhobadze	NGO Environmental League	Director
5	Liana	Garibashvili	Energy Efficiency Centre Georgia	Chief specialist
6	David	Girgvliani	SRF Gamma Consulting	Expert
7	Kety	Gujaraidze	NGO Green Alternative	Project Manager
8	Medea	Inashvili	Ministry of Environment of Georgia	Main Specialist
10	Nana	Janashia	Caucasus environmental NGO network	Director
11	Paata	Janelidze	UNDP GEF KfW Project Promotion of the use renewable energy resources for local energy supply - Georgia	Project Manager

	Name	Surname	Organisation	Position
12	Valeri	Kankia	Enguri Hydropower Station	Chairman of Supervisory Board
13	Otar	Kiria	Santsk-Javalcheti Roads Rehabilitation project by MCG	
14	Manana	Kochladze	Georgian environmental NGO	Project Manager
15	Grigol	Lazriev	CDM Georgian DNA	Contact Person
16	Grigol	Matcharadze	Enguri Hydropower Station	Technical Manager PIU
17	Joseph	Melitauri	World Bank mission in Georgia	Operations Officer, Infrastructure & Energy Department
18	Taras	Nijaradze	Basis Bank	Chairman of Supervisory Board
19	Nana	Pirtshelani	Ministry of energy of Georgia	Deputy Director of Policy and international relations Department
20	Mariam	Shotadze	United Nations Development project	Environmental Specialist / EFP
21	Marina	Shvangiradze	Coordinator of Georgia's Second National Communication to the UNFCCC	
22	Rusudan	Simonidze	The Greens Movement of Georgia / Friends of the Earth	Leader
23	Levan	Tavartkiladze	Ekoalliance Association	Director
24	Lia	Todua	Center for Strategic Research and Development of Georgia; Coordinator of Environmental Program	Director
25	Keti	Tsereteli	REC Caucasus	
26	Malkhaz	Tskvitishvili	Enguri Hydropower Station	Project Manager, PIU
27	David	Tvalabeishvili	World Bank mission in Georgia	Carbon Finance Coordinator, Infrastructure & Energy Department

The following questions and comments were made during the Stakeholder Consultation by the attendees (paraphrased and summarised version of the Question and Answer session):

1) Question posed by Marina Shvangiradze, coordinator of the second national communication of Georgia to the UNFCCC: “What is the reliability of the installed technology? Can we be assured that the installed technology is going to be sustainable and will operate successfully over the crediting period of the project?”

Answer given by Brendan Quigley, Project Manager for Consortium of International Engineering Consultants for the Enguri Project:
The Georgian engineering and construction firm Sakhydro was one of the contractors of this project and received training from the Consortium of International Engineering Firms during the first year of operation. The technology transfer resulted to be very successful since Sakhydro did not need any further training from the Consortium.
The turbines are in good state, the generators will be rehabilitated and re-installed. The monitoring and controlling system will ensure the reliability and sustainability of the system in the next 10 years.

2) Question posed by the audience (not clear by whom specifically): "What exact technical parts will be installed at the units included in the CDM project?"
Answer given by Malkhaz Tskvitishvili, Project Manger of the Enguri Rehabilitation Project Implementation Unit.
Turbines are already rehabilitated, while the CDM project will include the rehabilitation of the generators. Within the timeframe of the CDM project a state of the art monitoring and controlling equipment will be installed that will ensure the overall security and safety of the system.

3) Which pieces of equipment are of Soviet (Ukrainian) design and which are of German design?
Answer given by Brendan Quigley. The turbine is of Ukrainian design, while the generators, the monitoring and operation equipment are of German design (supplied by Voith Siemens).

4) Question posed by George Abulashvili, Director of the Energy Efficiency Center in Georgia and member of the CDM Council in Georgia: "How can the efficient volume of the reservoir be increased without increasing the surface area covered by the reservoir? "
Answer given by Brendan Quigley: This reservoir is very deep and since Enguri is a high mountain river there is the problem of sedimentation in the reservoir. In order to minimise sedimentation in the reservoir specialist companies are hired and they will be involved in the implementation of a sedimentation action plan (to minimise sedimentation in the reservoir).

5) Question posed by George Abulashvili, Director of the Energy Efficiency Center in Georgia and member of the CDM Council in Georgia: "What are the sources of data used to calculate the carbon emission factor of the Georgian grid? How reliable are these sources? Are they official sources?"
Answer given by Natalia Gorina, Senior Consultant, ICF International
The sources of data used for the calculation of the carbon emission factor of the Georgian grid are indicated in Annex 3 of the Project Design Document. The most important source of information for the calculation of the emission factor is the Central Electricity Dispatch Center of Georgia which provided the load data necessary for the calculation of the lambda factor, and thus the adjusted operating margin and the build margin. In addition, internationally recognised data, such as the IPCC factors were used in calculations. It can therefore be concluded that the data sources used are reliable.

6) Question posed by Medea Inashvili, Ministry of Environment: "What is the cost of rehabilitation of the three Enguri generation units?"
Answer given by Malkhaz Tskvitishvili. The cost of rehabilitation is around USD 5 million $ per unit. USD 45 million were earmarked for Phase 1 and USD 12 million for Phase 2.

7) Question posed by by Medea Inashvili: "How much payment will Engurhesi receive for the CERs stemming from this CDM project?"

Answer given by Natalia Gorina. The payment that Engurhesi will receive from the sale of CERs is still difficult to state given the fact that the CERs price is subject to negotiation. Nevertheless, I can give you a range of prices that were paid by potential carbon buyers in similar transactions. The prices per CERs currently paid are between EUR 5 and EUR 8-9 per tonne. Most of available buyers, including the newly created EBRD fund purchase CERs up to 2012 and offer an option to purchase CERs generated after 2012. CERs revenues can be obtained by multiplying the expected volume of this project for 5 years (2008-2012) and the range of CERs prices.

8) Question posed by George Abulashvili: “What is the time schedule for the next steps of the CDM cycle for this project, i.e. when do you expect validation, national approval and CDM registration to occur?”
Answer given by Natalia Gorina. We would like to engage in the next steps of the CDM process as soon as possible and proceed to collecting and preparing the necessary documentation for DNA approval later this month. At the same time an internationally recognised DOE will be selected to proceed to validation. We hope to obtain the registration of the project in 2007 or early 2008 but several factors are not under our control. In any case we try to speed up the CDM process as much as it is possible.

9) Question posed by audience: How much electricity produced by Enguri HPP goes to Abkhazia?
Answer given by Malkhaz Tskvitishvili: currently the Abkhazian side receives 36% of total electricity generated.

10) Question posed by Paata Janelidze, Project Manager of the UNDP GEF KfW Project Promotion of the use renewable energy resources for local energy supply - Georgia. Mr. Janelidze announced that he was very pleased with the quality of the Project Designed Document. He then commented on the issue of additionallity of this CDM project: since the rehabilitation of one unit has already been implemented successfully, there could be some concern in demonstrating the barrier analysis, given the fact that several barriers existed even initially, but still did not prevent the rehabilitation from taking place. Natalia Gorina replied that the major barrier which is present for the CDM project only is the lack of funding for the rehabilitation of Units #2, # 4, #1 and #5.
Mr. Janelidze then asked a clarification question on the data regarding calculation of the heat rate of thermal plants included in the operating margin. Natalia Gorina clarified the issue.

11) Question posed by Marina Shvangiradze, Coordinator of Georgia's Second National Communication to the UNFCCC: “Does this PDD include the monitoring plan? Who will be in charge of monitoring the emissions reductions?”
Answer given by Natalia Gorina: The Project Design Document includes a monitoring plan. The monitoring plan foresees that the electricity produced by the units of the Enguri HPP are metered according to the methodology ACM0002. The exact person in charge of monitoring at Enguri HPP will be nominated towards the end of the Rehabilitation Project.

12) Comment made by Grigol Lazriev, head of the Georgian Designated National Authority. For the purposes of approval of this CDM project by the Georgian DNA, the ACM0002 methodology needs to be applied in full and the simple adjusted operating margin calculation should be calculated for all three recent years (2006, 2005, 2004) (Note: at the time of the Stakeholder Consultation, only the 2006 load data were available to the Carbon Consultant and only the 2006 adjusted operating margin was calculated).

13) It was then discussed by several attendees what is the most reliable source of information on load data for the purpose of carbon emission factor calculation among the data provided by the Electricity Dispatch Center or the data provided by Georgian Ministry of Energy. It was concluded that the Electricity Dispatch Center supplies the best available data.

E.2. Summary of the comments received:

Eleven answered questionnaires were received. The vast majority of the received questionnaires were completed in Georgian. The following paragraphs summarise the comments received.

1) *Do you believe that the Enguri Rehabilitation project contributes to sustainable development of Georgia? Why?*

10 out of 11 answered questionnaires believe that the project does contribute to sustainable development, since the project allows the generation of electricity from a renewable source. This project is considered to be of strategic importance for sustainable development of Georgia. The project is very important for Georgia given the fact that Enguri contributes to about 40% of total electricity generation in Georgia. The Enguri HPP is currently running at a less efficient level than it its nominal rate. Thanks to the CDM project, the contribution of Enguri to CO2- free energy production will increase even further. One answered questionnaire notes that rehabilitating existing capacity avoids the construction of new electricity facilities with further environmental impacts. One answered questionnaire notes that this CDM project is better than the construction of the new Khudoni hydro power plant in Georgia.
One answered questionnaire comments that the sustainable development benefits will be evident only if new modern state of the art technology is transferred to Georgia and if these technologies are adapted successfully to local conditions.

2) *Can you identify any issues or omissions in the Environmental Impact Assessment of the Enguri Rehabilitation Project? Do you think it was conducted in a proper manner?*

Three people believe that since the full Environmental Impact Assessment was not attached to the PDD, they did not have a chance to evaluate the environmental impacts in full. The remaining 8 questionnaires did not foresee any further negative environmental impacts other than those cited in the Environmental Action Plan. Thus, the CDM project consisting in the rehabilitation of the three generation units itself does not impact the environment any further than the environmental impacts of the preexisting plant.

Several questionnaires underlined the fact that the Environmental Action Plan was conducted in a proper manner. No answered questionnaire noticed any negative environmental impact in connection to the CDM project.

3) *In your opinion, what are the potential negative environmental impacts that were not addressed?*

One answered questionnaire points out that a potential negative environmental impact can stem from potential changes of groundwater conditions in the Enguri floodplain, which could have impacts on the local population of the Samegrelo region. 3 questionnaires left the question blank.
All the remaining questionnaires did not find any negative environmental impacts.

4) *In your opinion, what are the potential negative impacts on the local communities that were not taken into account?*

Only two out of 11 questionnaires answered this question. The remaining 9 questionnaires left this question blank. One questionnaire pointed out the fact that the increased electricity production at Enguri HPP could potentially cause a smaller volume of water discharged downstream from the dam and the power station. This could potentially affect negatively the people living downstream of the river.
One answered questionnaire stated that all the economic and social aspects were well discussed during the presentation and they reflect the reality of the situation of the region.

E.3. Report on how due account was taken of any comments received:

The Environmental Action Plan was sent to those participants that required further information on the environmental aspects of the project. No other comments were received. All the comments given during the Stakeholder Consultation were taken into account in the final version of the Project Design Document.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The European Commission provides a grant of EUR 9.4 million to this CDM project. The European Commission confirms that such funding does not result in a diversion of official development assistance and is separate from and is not counted towards the financial obligations of the European Commission.

The European Commission will not claim any Certified Emission Reductions to be generated by the Enguri HPP Rehabilitation CDM project. These Certified Emission Reductions belong to the Government of Georgia.

Publicly available article on EBRD lending to Engurhesi Ltd and the Georgian government

Power to the people of Georgia

Power cuts were the daily routine in post-Soviet Georgia, with blackouts lasting for as long as two weeks. They became emblematic of the country's precipitous economic decline, played out in degraded living standards in what was once one of the USSR's most prosperous republics.

Households, businesses, hospitals and schools had to make do, or die. On the home front they substituted with often-faulty gas heaters (one of which killed Prime Minister Zurab Zhvania in 2005). Or they financed their own private generators, or paid bribes, in the case of some bigger industrial concerns, to ensure scarce power from the central system was diverted to them.

Since 1997 the EBRD and the European Commission (EC) have been helping to unpick the knots in Georgia's energy supply, in part by investing in the Enguri hydropower station, the country's main power source. It has been a long and torturous road and the job isn't finished yet, but residents can now flick on their light switches in Tbilisi at any time of day and find the electricity is working. Improvements at Enguri will help Georgia to reduce imports of expensive natural gas used for power generation and improve security of supply by replacing it with renewable domestic hydropower.

Geopolitical power play

Enguri was built in 1978 to provide peak electricity to the then Soviet Union. By the time the Soviet Union disintegrated in 1991, the plant urgently needed rehabilitation following years of zero maintenance. The plant's unit three shut down completely in 1993, robbing the country of 10 per cent of its power supply; other units operated below capacity.

Rehabilitation seemed impossible. The state argued it had no funds. And the plant straddles a disputed internal frontier with Abkhazia, a territory that has long fought for independence from Georgia.

Merab Davitaia is the Chief Engineer of Sakhydroenergomsteri, the state company that built the hydropower plant. He was just 22 years old when he moved to Sokhumi city – in what is now the Abkhazian-controlled zone – to build the Enguri power house.

He remembers that 21,000 people were employed to build the plant. "There I met my wife," says Mr Davitaia. In Sokhumi, his son, Temur, was born.

The plant became his life. He has spent 25 years in the settlement. The memory of watching it decay brings tears to the eyes of a now grey-haired Mr Davitaia.

In 1997, the EBRD agreed to lend the Georgian government $38.75 million to rehabilitate Enguri; the EC offered a grant of €9.4 million. "This was a brave decision as the plant was in a conflict zone," says Mr Davitaia.

The project floundered for a number of years for many reasons including the Abkhazia conflict and difficulties in tendering the project contracts in accordance with EBRD's stringent anti-corruption procurement rules.

At last, Georgian technicians were allowed to enter Abkhazia to repair the power house; in return, the Abkhazians would receive free energy.

Towards the power house

Driving towards the power house, Mr Davitaia feels uncomfortable going through an unofficial checkpoint manned by young Abkhazians. "There have been times when our workers have been kept at gunpoint," he says, "but I believe that the rehabilitation helped to build a working relationship with the Abkhazians."

In March 2006, armed guards from elsewhere in the Commonwealth of Independent States were brought to guard the plant on the Abkhazian side. One of them, aged 23, comments that "guards like me are essential to safeguard peace and normal life."

In the power house, all the equipment is new and carries English rather than Russian trademarks. "Three out of five energy generating units will be restored thanks to the EBRD loan and together they will produce enough to supply a quarter of the country's needs," says Malkhaz Tskvitishvili, the Project Manager.

He leads the way into the galleries within the 271-metre-high dam, the world's highest arch dam, and discusses with Laurent Chabrier, the EBRD banker involved in Enguri, how this loan has changed the plant.

The plant was shut down in March 2006 for rehabilitation of the pressure tunnel. Beneath the dam reservoir is a series of huge galleries, one atop the other, containing equipment essential to plant operations. "About 5.3 kilometres of galleries were rehabilitated," says Mr Tskvitishvili. "They were flooded in water."

The pressure gallery, 100 metres under the water reservoirs and the riskiest point of the dam site, was rehabilitated. So were the valve chamber, the pressure tunnel and the equipment to monitor geophysical movement that could weaken the dam.

A safer, more dependable dam

"It is now safer to work in the plant," observes Mr Chabrier. "This project has improved safety in terms of the dam, the workers and the region. Above all, it has brought reliable electricity to Georgia."

And that is not all. About 140 staff were trained thanks to a Swiss government grant, a road linking the power house with the dam was rebuilt and the workers' settlements were refurbished in Potskho, the 'village of the dam'. Five hundred people live there, of whom 300 are rehabilitating the dam.

Jimi Akubardia, one of them, disappears inside the dam every morning at 7am. He is too busy cleaning and dismantling equipment to have time for talk. His parents and grandparents depend on his $380 per month salary.

No power cuts in Tbilisi

"The three power units came back on stream after rehabilitation of the pressure tunnel on 14 July 2006, with one of them being new" says Mr Tskvitishvili. The EBRD is now considering extending the loan to cover rehabilitation of the remaining two energy generating units.

"The Enguri hydropower plant is essential to Georgia. It covers 40 per cent of Georgia's total energy consumption. The state was not strong enough alone to rehabilitate this plant," says Archil Mamatelashvili, Deputy Minister of Energy. "We needed the EBRD and the EC to raise finance."

Much has changed since the blackout days. A former Minister of Energy is now in prison, charged with corruption. And the power company will be able to fund its own maintenance programme: 70 per cent of customers now pay for electricity compared to only 30 per cent in 2002.

"Drive around the Georgian capital, Tbilisi, in the evening and you feel you are in a city as brightly lit as Las Vegas," says Malkhaz Tskvitishvili.

By Marjola Xhunga, communications adviser

14 August 2006

Source: http://www.ebrd.com/new/stories/2006/060822.htm

Annex 3

BASELINE INFORMATION

The emission factor for the Georgian grid (combined emission factor) has been calculated by the Georgian Designated National Authority (DNA), and presented in the "Baseline Emission Factor for the Electricity System of Georgia" [23] (DNA report). The step by step calculations is given below. These calculations are in compliance with the Version 02.2.0 of the "Tool to calculate the emission factor for an electricity system" (Tool), as demonstrated below.

Step 1: Identify the relevant electricity system:
The relevant electricity system for calculation of emission factor for Georgia is the Georgian electricity grid. The Georgian grid is the 'project electricity system' and covers all the plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints. The power plants included in the grid are assessed in the later steps to calculate the operating margin, the build margin leading to calculation of the combined margin.

As suggested in the Tool: '*if the DNA of the host country has published a delineation of the project electricity system and connected electricity systems, these delineations should be used*'. In case of Georgian – the DNA of Georgia has provided not only the delineation of the grid but also the calculation of grid emission factor for Georgia. This guidance from the DNA of Georgia been applied to determine the emission factor of Georgia.

Step 2: Choose whether to include off-grid power plants in the project electricity systems (optional)
The step 2 provides two options, of which Option I (Only grid power plants are included in the calculation) has been considered for calculating the grid emission factor of Georgian grid, i.e. any off-grid power plant is not included in the calculation.

Step 3: Select a method to determine the operating margin (OM)
In the electricity system of Georgia, low cost and must run resources constitute more than 50% of the total grid generation. As such, the simple adjusted operating margin ($EF_{OM,\ simple\_adjusted,\ y}$) has been selected to determine the operating margin of the Georgian grid.

Further as suggested by the Tool, the emission factor is calculated using the first data vintage (*Ex ante* option) available. According to this the emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. For grid power plants, a 3-year generation-weighted average, based on the most recent data available (available only till 2006) at the time of submission of the CDM-PDD to the DOE for validation.

Off-grid plants are not used for determining the emission factor of Georgia.

Step 4: Calculate the operating margin emission factor according to the selected method:
According to the Tool, the Simple Adjusted Operating Margin should be calculated as follows:

[23] Available at: www.moe.gov.ge/files/Klimatis%20Cvlileba/Grid_Emission_Factor_Georgia.pdf The Georgian DNA

[Equation 8 of the Tool]

$$EF_{grid,OM-adj,y} = (1-\lambda_y) * \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} + \lambda_y * \frac{\sum_k EG_{k,y} \times EF_{EL,k,y}}{\sum_k EG_{k,y}}$$

Where:

Parameter	Explanation
$EF_{grid,OM-adj,y}$	Simple adjusted operating margin CO_2 emission factor in year y (tCO_2/MWh)
λ_y	Factor expressing the percentage of time when low-cost/must-run power units are onthe margin in year y
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
$EG_{k,y}$	Net quantity of electricity generated and delivered to the grid by power unit k in year y (MWh)
$EF_{EL,m,y}$	CO_2 emission factor of power unit m in year y (tCO_2/MWh)
$EF_{EL,k,y}$	CO_2 emission factor of power unit k in year y (tCO_2/MWh)
m	All grid power units serving the grid in year y except low-cost/must-run power units
k	All low-cost/must run grid power units serving the grid in year y
y	The relevant year as per the data vintage chosen in Step 3

The Tool later states that $EF_{EL,m,y}$, $EF_{EL,k,y}$, $EG_{m,y}$ and $EG_{k,y}$ should be determined using the same procedures as those for the parameters $EF_{EL,m,y}$ and $EG_{m,y}$ in Option A of the simple OM method.

[Equation 2 of the Tool]

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

Where:

Parameter	Explanation
$EF_{EL,m,y}$	CO_2 emission factor of power unit m in year y (tCO_2/MWh)
$FC_{i,m,,y}$	Amount of fossil fuel type i consumed by power unit m in year y (Mass or volume unit)
$NCV_{i,y}$	Net calorific value (energy content) of fossil fuel type i in year y (GJ/mass or volume unit)
$EF_{CO2,i,y}$	CO_2 emission factor of fossil fuel type i in year y (tCO_2/GJ)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
m	All power units serving the grid in year y except low-cost/must-run power units
i	All fossil fuel types combusted in power unit m in year y

Parameter	Explanation
y	The relevant year as per the data vintage chosen in Step 3

For grid power plants, $EG_{m,y}$ should be determined as per the provisions in the monitoring tables, i.e. utility or government records or official publications should be applied.

When Equation 2 of the Tool is incorporated into the Equation 8 of the Tool, the result is as follows:

[Transformed Equation 8 of the Tool]

$$EF_{grid,OM-adj,y} = (1-\lambda_y) * \frac{\sum_m FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{\sum_m EG_{m,y}}$$
$$+\lambda_y * \frac{\sum_k FC_{i,k,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{\sum_k EG_{k,y}}$$

The DNA used the following formula to calculate Simple Adjusted emission factor:

[Equation 5 of the DNA report]

$$EF_{OM,simple,adjusted,y} = (1-\lambda_y) \times \frac{\sum_j F_{j,y} \times COEF_j}{\sum_j GEN_{j,y}} + \lambda_y \times \frac{\sum_k F_{k,y} \times COEF_k}{\sum_k GEN_{k,y}}$$

Where,

[Equation 4 of the DNA report]

$$COEF_i = NCV_i \times EF_{CO2,i} \times OXID_i$$

Where:

Parameter	Explanation
NCV_i	The net calorific value (energy content) per mass or volume unit of a fuel i
$OXID_i$	The oxidation factor of the fuel
$EF_{CO2,i}$	The CO_2 emission factor per unit of energy of the fuel i

The Equation 5 of the DNA report is the same as the transformed Equation 8 of the Tool (as presented above), considering that:

- F in the DNA report is the same as FC in the Tool; and
- GEN in the DNA is the same as EG in the Tool; and

- COEF in the DNA report is replaced with Equation 4 of the DNA report;
- Only natural gas is used for the electricity generation in Georgia, OXID=1.0 (as per IPCC default values).

Furthermore, considering that low-cost/must run sources (k) in Georgia are only hydro power plants, their CO_2 emission factor is equal 0. As such:

$$\frac{\sum_k F_{k,y} \times COEF_k}{\sum_k GEN_{k,y}} = 0$$

As a result, the Simple Adjusted OM has been calculated by the DNA with the following formula:

[Transformed Equation 5 of the DNA report]

$$EF_{OM,simple,adjusted,y} = \left(1 - \lambda_y\right) \times \frac{\sum_j F_{j,y} \times COEF_j}{\sum_j GEN_{j,y}}$$
$$= \left(1 - \lambda_y\right) \times \frac{\sum_j F_{j,y} \times NCV_i \times EF_{CO2,i} \times OXID_i}{\sum_j GEN_{j,y}}$$

As mentioned before, the operating margin emissions factor ($EF_{OM,\,y}$) has been calculated using a 3 year data vintage. For detailed calculations and information on data used, please refer to the DNA report. Below only one table has been extracted from the DNA report, which presents the relative energy contribution of each of the thermal plant connected to the grid. It also shows the calculated emissions for each plant and the developed simple operating margin for 2004, 2005 and 2006.

Parameter	Unit	2004	2005	2006
NCV_{cal}	Kcal / m^3	8,039.00	8,041.44	8,044.73
EF_C	tons of Carbon / TJ	15.30	15.30	15.30
OXID		1.00	1.00	1.00
Heat Content Conversion	Kcal / KJ	4.1868	4.1868	4.1868
NCV	TJ / 1000 m^3	0.03366	0.03367	0.03368
Emission Factor	tons of CO2 / TJ	56.10	56.10	56.10
Coefficient of Emission	tons of CO2 / 1000 m^3	1.8788	1.8793	1.8801
Fuel Consumed by each Thermal Plants:	1000 m^3			
1. Tbilsresi		9,755.00	108,909.00	232,662.00
AES Mtkvari		248,873.00	206,712.00	349,820.00
CCGT Energy-Invest		-	-	91,676.00
Emissions by each Thermal Plants:	tons of CO2			
Tbilsresi		18,419	205,693	439,639
AES Mtkvari		469,921	390,410	661,022
CCGT Energy-Invest		-	-	173,321
Total Emissions	tons of CO2	488,340	596,103	1,273,893
Generation from Other sources to the Grid	GWh	2,101.405	2,357.054	2,880.803

Parameter	Unit	2004	2005	2006
Operating Margin ($EF_{OM,y}$)	tCO2 equ. /MWh	0.2324	0.2529	0.4422

The description of how the Lambda factor (λ) has been calculated is provided in the DNA report, and it is in compliance with the Tool requirements. The table below presents the calculated Lambda factor for the determination of the simple operating margin for the year 2004, 2005 and 2006.

Year	Unit	Description	Value
2004	X	Number of hours low cost/must run resources are on the margin	1456
	λ	λ= X/8760	0.166
	1- λ		0.834
2005	X	Number of hours low cost/must run resources are on the margin	1179
	λ	λ= X/8760	0.135
	1- λ		0.865
2006	X	Number of hours low cost/must run resources are on the margin	521
	λ	λ= X/8760	0.059
	1- λ		0.941

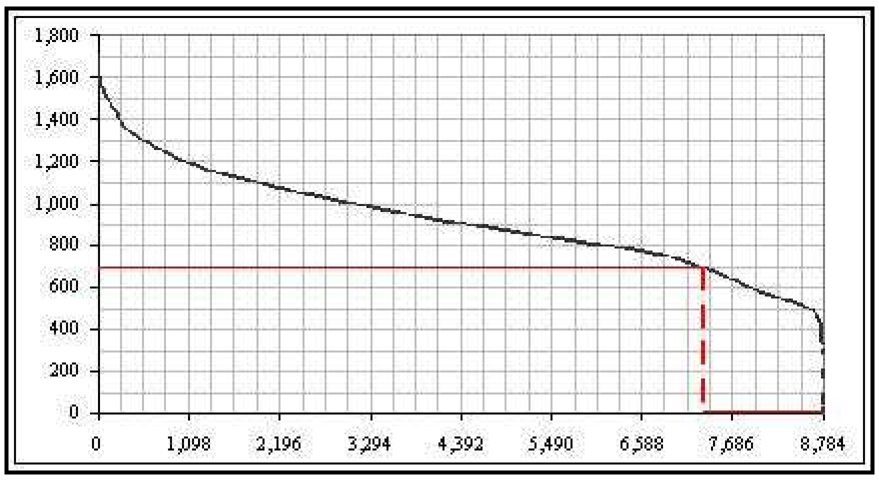
Furthermore,

$$EF_{OM,simple,adjusted,y} = (1 - \lambda) \times EF_{OM,y}$$

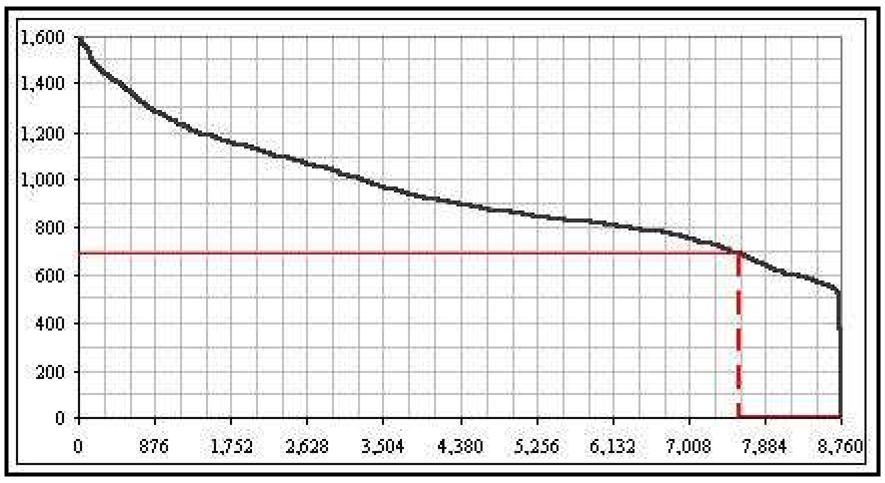
Year	λ	$EF_{OM,y}$	$EF_{OM,simple\_adjusted,y}$
2004	0.166	0.2324	0.1938
2005	0.135	0.2529	0.2188
2006	0.059	0.4422	0.4159

The weighted average $EF_{OM,simple\_adjusted,y}$ equals 0.27657tCO_2/MWh.

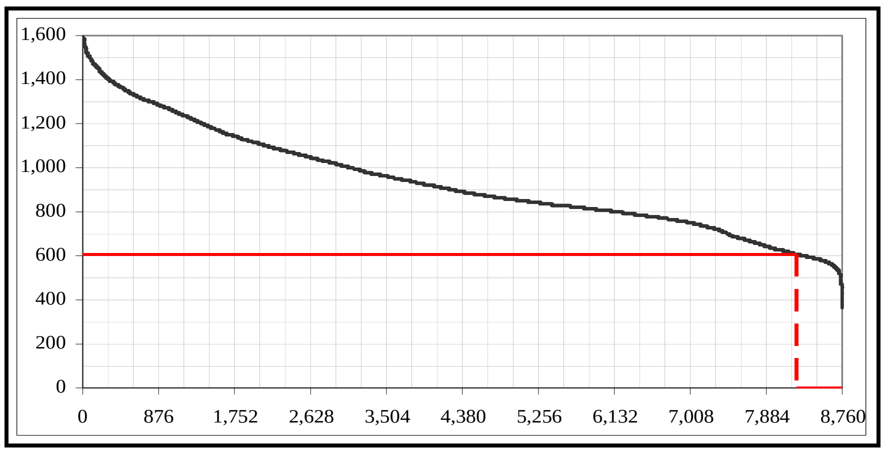
The figures below present the Load Duration Curve and the Must-run low-cost resources curve determined for the identification of their intersection point. The intersection point indicates the number of hours in the year when the low-cost must-run resources are on the margin in 2004, 2005 and 2006, respectively, on the Georgian grid.



2004 Load Duration Curve and the Must -run Low-cost Resources Curve



2005 Load Duration Curve and the Must -run Low-cost Resources Curve



2006 Load Duration Curve and the Must -run Low-cost Resources Curve

Step 5: Calculate the build margin (BM) emission factor:
Ex-ante option was used to calculate the build margin emission factor. The detailed description is provided in the DNA report.

The Tool requires using the Equation 13 to calculate the BM:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

The Georgian DNA used the following formula to calculate Build Margin emission factor:

[Equation 7 of the DNA report]

$$EF_{BM,y} = \frac{\sum_m F_{m,y} \times COEF_m}{\sum_m GEN_{m,y}}$$

Considering that the formula to calculate BM is analogous to the formula to calculate Simple OM, the proof that Equation 7 of the DNA report is in agreement with the Equation 13 of the Tool is the same as the proof provided for compliance of Equation 5 of the DNA report with the Equation 8 of the Tool.

In Georgia, there are no registered CDM projects undertaken at power plants. Therefore, power units older than 10 years have been included until the set has comprised 20% of generation.

For detailed calculations and information on data used, please refer to the DNA report. Below only one table has been extracted from the DNA report, which presents the plants included in calculations of the Build Margin emission factor:

No	Source	Start up date	capacity MW	Electricity delivered, GWh		Share, %		Emission, tCO_2eq
				Actual	Accumulated		Accumulated	
1	Zahesi	1927	36,8	158,984	7 396,739	2,15	100,00	
2	Abashahesi	1928	1,8	1,789	7 237,755	0,02	97,85	
3	Rionhesi	1933	48,0	290,473	7 235,966	3,93	97,83	
4	Dashbash	1936	1,3	5,948	6 945,493	0,08	93,90	
5	Atsihes	1937	16,0	70,946	6 939,545	0,96	93,82	
6	Kekhvihesi	1941	1,0	0,400	6 868,599	0,01	92,86	
7	Alazanhesi	1942	4,8	5,329	6 868,199	0,07	92,85	
8	Khrami-1	1947	113,0	334,691	6 862,870	4,52	92,78	
9	Chitakhevhesi	1949	21,0	106,833	6 528,179	1,44	88,26	
10	Khertvisihesi	1950	0,3	0,608	6 421,346	0,01	86,81	
11	Mashaverahesi	1951	0,6	0,300	6 420,738	0,00	86,80	
12	Tiriponhesi	1951	3,0	3,001	6 420,438	0,04	86,80	
13	Kazbegihesi	1951	0,3	0,452	6 417,437	0,01	86,76	
14	Kabalihesi	1953	13,6	28,345	6 254,557	0,38	84,56	

No	Source	Start up date	capacity MW	Electricity delivered, GWh		Share, %		Emission, tCO_2eq
				Actual	Accumulated		Accumulated	
15	Martkophesi	1953	14,0	44,887	6 226,212	0,61	84,18	
16	Ortachalhesi	1954	1,5	0,836	6 416,985	0,01	86,75	
17	Shaorhesi	1955	3,9	5,989	6 416,149	0,08	86,74	
18	Tetrikhevhesi	1956	18,0	88,574	6 410,160	1,20	86,66	
19	Satskhenisihesi	1956	38,4	67,029	6 321,586	0,91	85,46	
20	Gumathesi	1956	67,0	220,228	6 181,325	2,98	83,57	
21	Dzevrulhesi	1956	60,0	84,326	5 961,097	1,14	80,59	
22	Machakhelahesi	1956	1,4	6,438	5 876,771	0,09	79,45	
23	Squrhesi	1958	12,0	46,834	5 868,873	0,63	79,34	
24	Bzhuzhahesi	1958	1,0	1,460	5 870,333	0,02	79,36	
25	Lajanurhesi	1960	112,0	274,695	5 822,039	3,71	78,71	
26	Misaktsieli-Ento	1961	2,7	4,737	5 547,344	0,06	75,00	
27	Khrami-2	1963	110,0	118,204	5 542,607	1,60	74,93	
28	Sionhesi	1964	9,1	28,211	5 424,403	0,38	73,34	
29	Tbilsresi	1965	150,0	663,910	5 396,192	8,98	72,95	439 624
30	Ritseulahesi	1967	6,1	24,114	4 732,282	0,33	63,98	
31	Chkhorhesi	1967	5,4	6,071	4 708,168	0,08	63,65	
32	Vardnilhesi	1971	220,0	344,477	4 702,097	4,66	63,57	
33	Vartsikhehesi	1976	184,0	721,062	4 357,620	9,75	58,91	
34	Engurhesi	1978	1 300,0	1652,111	3 636,558	22,34	49,16	
35	Zhinvalhesi	1985	130,0	390,355	1 984,447	5,28	26,83	
36	AES Mtkvari	1990	300,0	1149,449	1 594,092	15,54	21,55	660 999
37	Intsobahesi	1993	1,7	2,265	444,643	0,03	6,01	
38	JSC"Kindzmarauli"	2001	1,5	2,561	442,378	0,03	5,98	
39	Munleik-Georgia	2002	20,0	22,172	439,817	0,30	5,95	
40	Khadorhesi	2004	24,0	127,201	417,645	1,72	5,65	
41	"Energy Invest" Gas turbine-1	2006	110,0	290,444	290,444	3,93	3,93	173 226
Total (36-41)				**1 594,092**				**834 225**

The table below presents the calculated emissions for each plant included in the build margin and the value of build margin.

Recent Plants in the Build Margin contributing to 20% generation	Capacity	Generation	Emission of CO_2
	MW	million kWh	tons of CO_2
AES Mtkvari	300.00	1,149.45	661,022
Intsobahesi	1.65	2.27	
Chalahesi	1.50	2.56	
Munleik-Georgia	20.00	22.17	
Khadorhesi	24.00	127.20	
CCGT Energy-Invest	110.00	290.44	173,231

Recent Plants in the Build Margin contributing to 20% generation	Capacity	Generation	Emission of CO_2
	MW	million kWh	tons of CO_2
Total	457.15	1,594.09	834,253
Build Margin ($EF_{BM,y}$) (kg CO_{2eq}/ kWh)			0.5233

Step 6: Calculate the combined margin emissions factor

The baseline emission factor EF_y is calculated as the average of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$). The Tool provides the formula:

[Equation 14 of the Tool]

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$

The DNA report follows the same formula, considering that:

- $EF_{baseline}$ in the DNA report is the same as $EF_{grid,CM,y}$ in the Tool; and
- $EF_{Operating\ Margin}$ in the DNA is the same as $EF_{grid,OM,y}$ in the Tool; and
- $EF_{Build\ Margin}$ in the DNA is the same as $EF_{grid,BM,y}$ in the Tool.

According to the Tool the default values are: $w_{OM} = w_{BM} = 0.5$.

$$EF_{Baseline} = 0.5 \times (0.27657 + 0.52332) tCO_2/MWh = 0.39995\ tCO_2/MWh$$

Please see table below for details:

Year	Operating Margin of power sources other than low-cost must run resources ($EF_{OM,y}$) (kg CO2 / kWh)	Operating Margin of power sources other than low cost must run resources adjusted with (1- λ) ($EF_{OM,simple\ adjusted,y}$) (kg CO2 / kWh)	System Generation (GEN_y) (`000 kWh)	Build Margin ($EF_{BM,y}$) (kg CO2/ kWh)	Emission Coefficient for the Grid (EF_y) (kg CO2 / kWh)
2004	0.2324	0.1938	7,994.51		
2005	0.2529	0.2188	8,277.38		
2006	0.4422	0.4159	8,173.74	0.5233	
Generation-Weighted Average of 3 Years			0.2752		
Average of Operating Margin and Build Margin ($EF_{Grid,CM,y}$)					0.3999

In summary, the DNA calculations of the baseline emission factor are in compliance with the latest version of the Tool to calculate emission factor.

Annex 4

MONITORING INFORMATION

The monitoring of the CDM project activity has been described in detail in the section B.7 of the PDD. The monitoring of the CDM project activity has been planned in accordance with the requirement of the approved monitoring methodology ACM0002 (Version 12.1.0)

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