PROJECT DESIGN DOCUMENT FORM
FOR CDM PROJECT ACTIVITIES (F-CDM-PDD)
Version 04.1

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	Dariali Hydroelectric Power Project
Version number of the PDD	Version 1
Completion date of the PDD	25/07/2012
Project participant(s)	JSC Dariali Energy
Host Party(ies)	Georgia
Sectoral scope and selected methodology(ies)	1 : Energy industries (renewable - / non-renewable sources)
Estimated amount of annual average GHG emission reductions	267,821

SECTION A. Description of project activity
A.1. Purpose and general description of project activity
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Dariali Hydroelectric Power Project (hereafter referred to as the “Project”) developed by JSC Dariali Energy (hereafter referred to as the “Project Developer”), is a grid-connected hydropower plant with a run-of-river reservoir in Kazbegi region, in Georgia (hereafter referred to as the “Host Country”). Total installed capacity of the Project will be 108 MW consisting of 3 sets of 36 MW turbine and generator, with a predicted electricity supply to the grid of 505 GWh per annum. As such the Project is a Type I renewable energy project under Sectoral scope 1.

The purpose of the Project is to utilise the hydrological resources of the Tergi River in order to generate low emissions electricity for the Georgia national grid, thereby displacing electricity that is relatively carbon intensive, with a Combined Margin Emission Factor of 0.53034 tCO_2/MWh, and reducing greenhouse gas (GHG) emissions. The baseline scenario is the same as the scenario existing prior to the start of the implementation of the project activity: Electricity delivered to the Grid by the Project would have otherwise been generated by the operation of grid-connected power plants, and by the addition of new generation sources.

The Project will contribute to sustainable development of the Host Country. Specifically, the Project:

- Reduces the countries dependence of fossil fuel imports and thereby enhances the level of energy security;
- Helps to stimulate the growth of the private hydro power industry in Georgia;
- Increases employment opportunities in the area where it is located. The Project therefore contributes to poverty alleviation;
- Enhances the local investment environment, and therefore improves the local economy;
- Diversifies the sources of electricity generation. This is important for meeting growing energy demands, and transitioning away from diesel and coal-supplied electricity generation;
- Makes use of renewable hydroelectric resources that is in line of the State Program – “Renewable Energy 2008”.

A.2. Location of project activity
A.2.1. Host Party(ies)
>>
Georgia

A.2.2. Region/State/Province etc.
>>
Kazbegi region

A.2.3. City/Town/Community etc.
>>
Stepantsminda city

A.2.4. Physical/Geographical location
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The exact location of the Project is defined using geographic coordinates obtained with a Global Positioning System (GPS) receiver: Latitude 42°39´58", Longitude 44°38´43

A.3. Technologies and/or measures

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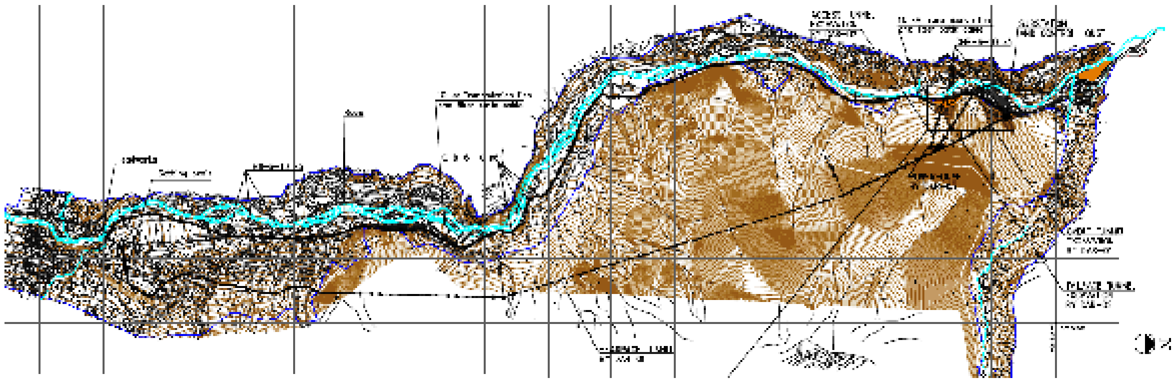
The purpose of the Project is to use well-established hydro power generation technology for electricity generation and transmission. This low emissions electricity will be delivered to the Grid, thereby displacing CO_2 emissions from Grid-generated electricity. The baseline scenario is the same as the scenario existing prior to the start of the implementation of the project activity: Electricity delivered to the Grid by the Project would have otherwise been generated by the operation of grid-connected power plants, and by the addition of new generation sources. Equipment and systems in operation in the scenario existing prior to the start of the implementation are all power plants physically connected to the Grid to which the Project is connected. The Grid includes the Georgia national grid.

The Project is a hydropower plant with a run-of-river reservoir, and has a total installed capacity of 108 MW (consisting of 3 x 36 MW generators).

The Project consists of an intake structure, the water conveyance system, and the powerhouse. The water intake structure is located on the upstream portion of the Tergi River, and consists of a low concrete dam spillway structure and conventional concrete intake structure comprising of three inlet openings, which directs part of the river flow into the water conveyance system. The spillway dam has no storage function and only creates a small holding pond. The power density of the Project, given as the total capacity (in W) divided by the surface area of the full reservoir (in m2), is shown to be 43200 W/m2. The conveyance system comprises of diversion pipe, sand basin, diversion conduit sand basin-tunnel entrance, a headrace tunnel, surge facilities, pressure shaft and distributors. It forms a 379.3 m water head to take advantage of the natural height drop of the river, and carries the water to the powerhouse.

The water enters, through high pressure pipelines, into the turbines installed in the powerhouse. After power generation, the water is discharged into the Tergi River through a tailrace.



There will be separate step-up transformers for each unit, from generator voltage to 110 kV. The transformers will be located outside the cavern at the substation area. The substation will be connected to the existing 110kV transmission line running along the Tergi river right next to the substation.

Monitoring equipment details, including location(s) are provided in Section B.7.2. of the PDD.

Table A.4.1. Main technical parameters of the proposed Project

	Value	**Source**
Forecast installed capacity (MW)	3 x 36	FSR *
Mean annual output (MWh)	510 000	FSR
Forecast annual power supply to the grid (MWh)	505 000	FSR
Turbine Type	Vertical Pelton	FSR
Rated Speed (rpm)	375	FSR
Rated generator capacity (MVA)	3x45	FSR
Water head (m)	379.3	FSR
Design flow (m^3/s)	22.4	FSR
Lifetime (years)	20	FSR

*The Feasibility Study Report (FSR) was developed by Landsvirkjun Power on September 2011

A.4. Parties and project participants

Party involved (host) indicates a host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Georgia (host)	JSC Dariali Energy	No

A.5. Public funding of project activity

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The Project will not receive any public funding from Parties included in Annex I of the UNFCCC

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

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1. The approved consolidated baseline and monitoring methodology ACM0002: “Consolidated baseline methodology for grid-connected electricity generation from renewable sources”, Version 13.0;
2. The approved “Tool for demonstration and assessment of additionality”, Version 6.0.0 and
3. The approved “Tool to calculate the emission factor for an electricity system”, Version 02.2.1 are applied to the Project activity.

Further information pertaining to the methodology can be obtained at:
http://cdm.unfccc.int/

B.2. Applicability of methodology
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ACM0002 (Version 13.0) is chosen and applicable to the proposed project for the following reasons:

Criteria	Project situation
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 project activity is a grid-connected renewable power generation project activity that installs a new hydro power plant at a site where no renewable power plant was operated prior to the implementation of the project activity.
In the case of capacity additions, retrofits or replacements (except for capacity addition projects for which the electricity generation of the existing power plant(s) or unit(s) is not affected): 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 addition 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 Project does not involve capacity additions, retrofits or replacements of existing plants
In case of hydro power plants: • At least one of the following conditions must apply: o The project activity is implemented in an existing single or multiple reservoirs, with no change in the volume of any of the reservoirs; or o The project activity is implemented in an existing single or multiple reservoirs, where the volume of any of reservoirs is increased and the power density of each reservoir, as per the definitions given in the Project Emissions section, is greater than 4 W/m^2 after the implementation of the project activity; or o The project activity results in new single or multiple reservoirs and the power density of each reservoir, as per the definitions given in the Project Emissions section, is greater than 4 W/m^2 after the	The project activity results in new single run of river reservoirs and the power density of the reservoir is (43200 W/m^2) therefore, greater than 4 W/m^2.

implementation of the project activity. In case of hydro power plants using multiple reservoirs where the power density of any of the reservoirs is lower than 4 W/m^2 after the implementation of the project activity all of the following conditions must apply: • The power density calculated for the entire project activity using equation 5 is greater than 4 W/m^2; • All reservoirs and hydro power plants are located at the same river and were designed together to function as an integrated project that collectively constitutes the generation capacity of the combined power plant; • The water flow between the multiple reservoirs is not used by any other hydropower unit which is not a part of the project activity; • The total installed capacity of the power units, which are driven using water from the reservoirs with a power density lower than 4 W/m^2, is lower than 15 MW; • The total installed capacity of the power units, which are driven using water from reservoirs with a power density lower than 4 W/m^2, is less than 10% of the total installed capacity of the project activity from multiple reservoirs.	
The methodology is not applicable to the following: • Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site; • Biomass fired power plants; • A hydro power plant that results in the creation of a new single reservoir or in the increase in an existing single reservoir where the power density of the reservoir is less than 4 W/m^2	The Project does not involve switching from fossil fuels to renewable energy sources at the site of the project activity The Project does not involve biomass power plants. The project activity results in new single reservoirs and the power density of the reservoir, is greater than 4 W/m^2

B.3. Project boundary

Source		GHGs	Included?	Justification/Explanation
Baseline scenario	CO2 emissions from electricity generation in fossil fuel fired power plants connected to the Georgia national grid	CO_2	Yes	Main emission source
		CH_4	No	Minor emission source.
		N_2O	No	Minor emission source.
Project scenario	Emissions of CH4 from the reservoir	CO_2	No	Minor emission source
		CH_4	No	Since the power density of the project is greater than 10 W/m^{2,} no GHG emissions from the project have to be considered according to ACM0002.
		N_2O	No	Minor emission source.

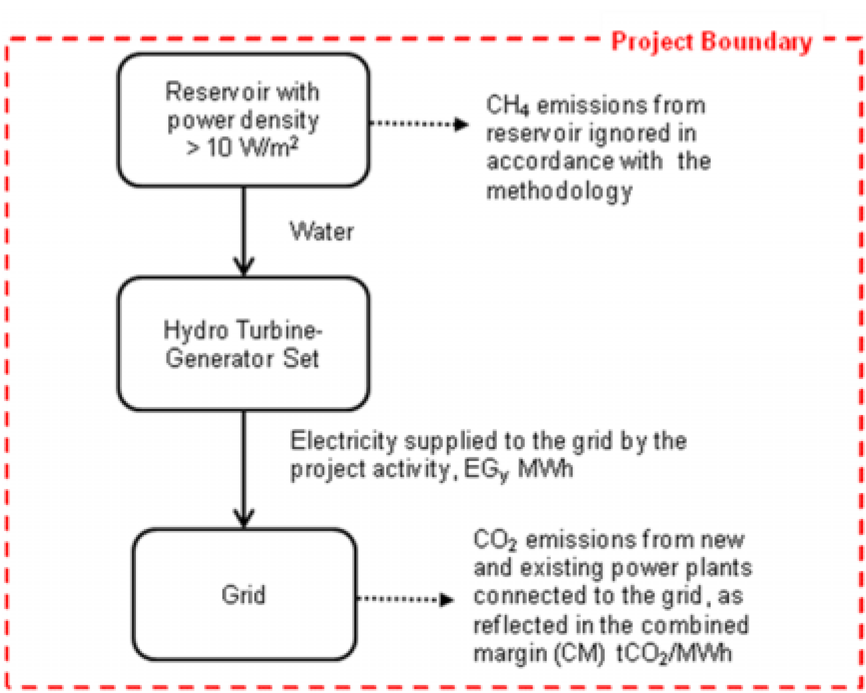

Figure B.1 Flow diagram of the project boundary

B.4. Establishment and description of baseline scenario

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As the project activity is the installation of a new grid-connected renewable power plant, the baseline scenario is the following:

> *Electricity delivered to the grid by the Project activity would have otherwise been generated by the operation of grid-connected power plants, and by the addition of new generation sources, as reflected in the Combined Margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".*

B.5. Demonstration of additionality
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CDM Consideration

According to the CDM Project Standard, if the start date of a proposed CDM project activity is prior to the date of publication of the PDD for the global stakeholder consultation, project participants shall demonstrate that the CDM benefits were considered necessary in the decision to undertake the project as a proposed CDM project activity.

Given the starting date of the project activity is after 02 August 2008, the project participant informed the Georgian DNA and the UNFCCC secretariat in writing of the commencement of the project activity and of the intention to seek CDM status, in line with EB 49 Annex 22. This notification was made within six months of the project activity start date as shown in the timeline below.

The project entity was aware of and considered CDM incentives before the start of the project activity. The key events of the implementation of the project activity are indicated below, which indicate that CDM is a key factor for investment decision.

Milestone	Date
Dariali Energy LLC was established with the objective to construct Dariali HPP	December 2010
Agreement signed between the Ministry of Energy and Dariali LLC	May 2011
Feasibility Study Report prepared by Landsvirkjun Power	September 30th 2011
Decision on CDM development	October 4th , 2011
Dariali Energy LLC reorganised into Dariali Energy JSC with the specific objective to implement the HPP.	October 2011
Environmental and social assessment completed	December 2011
Construction permit was issued by the Ministry of Economic and Sustainable Development of Georgia	November 30th , 2011
Contract for construction of the powerhouse access tunnel and the tailrace tunnel	February 15th , 2012
Contract for construction of the headrace tunnel	February 24th , 2012
Request of the Letter of Endorsement from the Ministry of Environment Protection of Georgia to the CDM project	March 19th , 2012
Issuance of the Letter of Endorsement from the Ministry of Environment Protection of Georgia to	March 26th , 2012

the CDM project	
Submission of the prior consideration of the CDM form to the UNFCCC	March 30th , 2012
RFQ for the CDM consultant	April 9th 2012
Contract CDM consultant to Implement the Project	April 24th , 2012
Validation contract with LRQA	June 21st , 2012

Project start date:
According to the CDM Glossary of terms, the project starting date is defined as "*The starting date of a CDM project activity is the date at which the implementation or construction or real action of a project activity begins... 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…*"

Based on this definition, the project starting date is deemed to be the 15/02/2012 which is the date when contract for construction of the powerhouse access tunnel and the tailrace tunnel has been signed.

Additionality
The following steps are used to demonstrate the additionality of the Project according to the latest version of the "Tool for the demonstration and assessment of additionality" approved by the Executive Board.

Step 1. Identification of alternatives to the project activity consistent with current laws and regulations

The determination of project scenario additionality is done using latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Executive Board.

Sub-step 1a. Define alternatives to the project activity:

Project activities that apply the tool in context of approved consolidated methodology ACM0002 only need to identify that there is at least one credible and feasible alternative that would be more attractive than the proposed project activity. The following two alternatives to the Project activity are considered here in detail:

Alternative 1: The proposed Project activity undertaken without being registered as a CDM project activity, i.e. the construction of a new hydroelectricity generation plant with an installed capacity of 108 MW, connected to the local grid, and implemented without considering CDM revenues.

Alternative 2: Continuation of the current situation, i.e. electricity will continue to be generated by the existing generation mix operating in the grid.

Sub-step 1b. Consistency with mandatory laws and regulations:

Both scenarios are in compliance with all mandatory applicable legal and regulatory requirements.

Overview of the electricity sector in Georgia

The legal and regulatory frameworks of the Georgian electricity sector have been significantly changed over the last decade. The key regulatory landmarks of this reform include:

- 'Law of Georgia on Electricity and Natural Gas' of 27 June 1997;
- 'Law of Georgia on Independent National Regulatory Authorities' (coming into effect from 15 October 2002);
- Law on Licensing and Permits of 2005;
- General Administrative Code of Georgia which applies to all state agencies;
- Electricity (Capacity) Market Rules of 1 September 2006;
- State Program "Renewable Energy 2008" about Approval of the Rule to Enable the Construction of Renewable Energy Sources in Georgia, of 18 April 2008
- Georgian National Energy and Water Regulatory Commission Decree on the Electricity Tariffs of 4 December 2008;

The state electricity company has been unbundled into generation, transmission and distribution companies, and the generation and distribution sector is mostly privately owned. An independent regulator, GNEWRC, regulates the sector, while the Ministry of Energy sets policies and is responsible for facilitating large investment projects.

In 2006 the Electricity System Commercial Operator (ESCO) was created with the responsibility for balancing the electricity demand and supply. The company is also responsible for contracting for electricity export and import. ESCO is a commercial entity owned by the Georgian state, though the government plans to privatise ESCO in the coming years.

In practice, power producers have two options when selling their electricity: Entering into a direct contract with a customer or selling the electricity to the Electricity System Commercial Operator (ESCO).

Generation is dominated by hydro power, which constituted 88% of total generation in 2009. HPPs have been developed with limited reservoir storage capacity. Approximately 10% of annual generation can be placed in storage compared with, e.g., 70% in Norway, which also has a hydro-based electricity system.

Limited storage capacity and significant spring and summer peaks in river flows result in an uneven annual generation profile and significant water spill in wet years. For this reasons electricity generation prices in Georgia fluctuate significantly over the year.

The price paid by ESCO reflects the marginal cost of generating electricity in the Georgian system. The ESCO prices are very low in the summer because of a surplus of electricity in the Georgian system and limited export options. [1]

As mentioned above a State Program "Renewable Energy 2008" was approved by the Government of Georgia in April 2008. It regulates the development of HPPs with an installed capacity up to 100 MW. The Law on Electricity and Natural Gas sets out new procedures for obtaining generation licences for green field hydro power sites and a new regulatory regime for tariffs for newly constructed hydro power plants. The State Program states that all newly constructed hydro power plants with a turbine size up to 13 MW will be fully deregulated and can sell electricity to the company prepared to purchase electricity for the highest price either in Georgia or abroad.

For hydropower sites with turbine size from 13 to 99 MW, the producer is required to sell electricity in Georgia the first 10 years of operations for three months out of the year. The exact months of the year

[1] THE ELECTRICITY SECTOR IN GEORGIA – AN OVERVIEW, Commissioned Georgia

will be agreed between the government of Georgia and the project developer. The electricity can be sold freely domestically in Georgia or to ESCO.

For projects with installed turbine size of 100 MW or more, specific rules apply. The rules regulating the development of these projects will be set out in the tender documents for the sites.

Although the installed capacity of Dariali Hydropower Plant is above the 100MW threshold, i.e. 108 MW, the rules applicable to turbine size from 13 to 99 MW have been applied to the Project, as described in the Agreement signed between Dariali, the Ministry of Energy and Natural Resource, Energotrans and ESCO.

Step 2. Investment Analysis

Sub-step 2a. Determine appropriate analysis method

According to the latest version of the "Tool for the demonstration and assessment of additionality", three options can be applied to conduct the investment analysis. These are Simple Cost Analysis (Option I), Investment Comparison Analysis (Option II), and Benchmark Analysis (Option III).

Since this Project and the alternatives will generate financial/economic benefits (other than CDM related income) via the sale of generated electricity, Option I (Simple Cost Analysis) is not applicable.

According to the Additionality Tool, if the alternative to the CDM project activity does not include investments of comparable scale to the Project, then Option III must be used.

Given that the project developer does not have alternative and comparable investment choices, Benchmark Analysis (Option III) is more appropriate than Investment Comparison Analysis (Option II) for assessing the financial attractiveness of the project activity.

Sub-step 2b. Option III – Application of benchmark analysis

The likelihood of development of the Project, as opposed to the continuation of the generation of grid electricity from the existing generation mix (i.e. *Alternative 2* - the baseline), will be determined by comparing the Project IRR without CDM financing (*Alternative 1*) with benchmark rates applicable to a local investor, i.e. those provided by national authorities, local banks, or investment bonds in the Host Country.

According to the "Guidelines on the Assessment of Investment Analysis", for the selection of Appropriate benchmarks, in cases of projects which could be developed by an entity other than the project participant, the benchmark should be based on parameters that are standard in the market. If so, the cost of equity can be determined by selecting the values provided in Appendix A of the referred guidelines.

A weighted average cost of capital (WACC) is used as the appropriate benchmark to compare with the project's return. The selected approach is widely accepted as a suitable approach among financial managers to take investment decisions. A Post tax WACC is used in keeping with the FSR.

The formula applied to calculate the post tax WACC is the following:

WACC[2]= Cost of Equity (%) x (1 - Debt Part (%)) + Cost of Debt (%) x Debt Part (%) x (1- Tax rate)

[2] http://www.investopedia.com/terms/w/wacc.asp

Parameters used in benchmark determination for this financial analysis is summarised in the table below:

Parameter	Value	Source
Cost of Equity	12.9%	Guidelines on the assessment of Investment Analysis (EB62)
Cost of Debt	12.74%	FSR based on Market Interest Rates on Loans provided by the National Bank of Georgia[3].
Debt ratio	70%[4]	FSR
Corporate profit tax	15%	
WACC	11.45%	Calculated as WACC formula given above and in the IRR sheet. (12.90%*(1-70%) + 12.74%*(70%)*(1-0.15) = 11.45%

The parameters listed below are the main parameters used in the financial analysis.

- **Table B.5.1.** Main parameters used in the investment analysis

Name	Value	Source
Installed capacity (MW)	108	FSR
Electricity Generation (MWh)	510 000	FSR
Expected power supplied to the grid (MWh)	505 000	FSR
Capacity Factor (%)	51	FSR
Corporate profit tax (%)	15	FSR
Property Tax (%)	1%	FSR
Total investment (USD)	119,959,310	FSR
Operating costs (USD/yr)	1% of Capex	FSR
Electricity tariff, USD/MWh	33.61	FSR
Depreciation (years)	20	FSR

Sub-step 2c: Calculation and comparison of financial indicators

The Table below shows the IRR obtained as a result of the financial analysis for the project activity. As shown, the project IRR is lower than the benchmark.

Table B.5.2 Summary of project investment analysis without CDM financing

IRR	9.00%

Sub-step 2d: Sensitivity analysis

[3] http://nbg.gov.ge/index.php?m=306&lng=eng

[4] Based on project Developers expectations

A sensitivity analysis was conducted using assumptions that are conservative from the point of view of analysing additionality, i.e. the 'best-case' conditions for the Project IRR were assumed by altering the following parameters:

- Operating costs
- Investment costs
- Electricity tariff
- Annual power supplied to the grid

Table B.5.2 summarizes the results of the sensitivity analysis, showing the variation of each parameter required to reach the 11.45% benchmark.

Table B.5.2. Results of the sensitivity analysis

	% Variation of the parameter required to reach the benchmark
Operating costs	---
Investment costs	-26%
Electricity tariff	+34%
Annual power supplied to the grid	+25%

These variations do not reflect a realistic range of assumptions for the input parameters of the financial analysis.

Operating costs: The results of the sensitivity analysis mean that even if the Project incurred zero operating costs, which is not reasonable, the IRR of the Project would not reach the 11.45% benchmark.

Investment costs: 26% of decrease in investment costs is very unlikely to happen. For the proposed Project, investment costs have already decreased by 11% if compared with the initial estimates developed at the time the Agreement was signed with the Electricity System Commercial Operator (ESCO). This can be explained by improvements to the original design. Therefore, a further decrease of 26% in investment costs is extremely unlikely, and that the IRR is not likely to reach the 11.45% benchmark.

Electricity tariff: The electricity tariff used in the financial analysis is also consistent with the FSR. Electricity tariff is calculated based on the weighted average between the winter tariff agreed in the Agreement signed between Dariali Energy LLC, the Ministry of Energy and Natural Resource, Energotrans and ESCO, and the highest electricity tariff paid by ESCO to medium and large hydropower plants during the summer months.

According to the Agreement, for the first ten years operation, beginning from the date of commencement of Commercial Operation of the Facility, the full power output of Facility during the winter months of each year, (being the months of December, January and February (the "**Winter Months**") shall be sold exclusively for the purpose of meeting the internal demand of Georgia under the Guaranteed Power Purchase Agreement to be signed with ESCO with a tariff of 6.5 USD cent per KWh at the bus bar. In the other months of each operational year Dariali has the right at its sole discretion to choose which market to sell electricity produced by the Facility and the price at which it shall be sold.

Dariali has the option to sell to ESCO, export, or sell to distributing companies or direct consumers. However, given the fact that distributing companies have their own generation capacity and so do not provide favourable rates to other power producers, and the insufficient trans the seasonal surplus to neighboring countries, the only option left to Dariali is to sell the electricity generated during the summer months to ESCO.

Given there is no PPA for the electricity generated between March and November, the FSR has used the weighted average tariff calculated based on maximum tariff paid by ESCO to Medium and Large hydropower plants between in 2010-2011 (until September 2011 when the FSR was finalized) as reference for the financial analysis[5].

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Year	Maximum tariff paid by ESCO to Medium and Large hydropower plants, Tetri/kWh								
2010	8.750	8.750	1.187	1.187	1.187	1.187	8.750	8.750	8.750
2011	8.750	8.750	4.214	4.214	4.214	1.187			
2-year maximum	**8.750**	**8.750**	**4.214**	**4.214**	**4.214**	**1.187**	**8.750**	**8.750**	**8.750**

The Project tariff has been calculated by weighting both winter and summer tariff by the expected electricity generated by the Project month by month. As a reference the 1-yer period from September 2010 to August 2011 was chosen.

	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Total
Monthly generation of Dariali HPP, GWh	54.110	37.450	23.740	18.870	15.540	12.820	14.590	27.830	69.390	77.780	80.250	77.280	**510**
Monthly supply to the grid, GWH	53.623	37.113	23.526	18.700	15.400	12.705	14.459	27.580	68.765	77.080	79.528	76.584	**505**
Highest tariff of ESCO, GEL[6]/MWh	87.50	87.50	87.50	87.50	87.50	87.50	87.50	87.50	42.14	42.14	42.14	11.70	
Exchange rate, USD/GEL	1.8307	1.8063	1.778				1.741	1.7056	1.6408	1.6663	1.6628	1.6549	
Highest tariff of ESCO, USD/MWh	47.80	48.44	49.21				50.26	51.30	25.68	25.29	25.34	7.07	
Tariff according to Agreement with ESCO, USD/MWh				65.00	65.00	65.00							
Monthly income, 1000 USD	2,563	1,798	1,158	1,216	1,001	826	727	1,415	1,766	1,949	2,015	541	**16,975**
Weighted average tariff, USD/MWh	**33.61**												

Therefore 33.61 USD/MWh has been the tariff applied in the financial analysis in the FSR. This tariff is deemed to be conservative as it assumes Dariali will be able to secure an electricity tariff equal to maximum tariff paid by ESCO to any of HPP with a capacity above 13MW. Even if those conditions are achieved as the IRR is below the benchmark and require a further increase of 34% to reach the benchmark

[5] http://www.esco.ge/index.php?article_id=57&clang=1

[6] 1 GEL = 100 Tetri

Annual power supplied to the grid: The expected annual power supplied to the grid by the Project indicated in the Feasibility Study Report has been calculated by Landsvirkjun Power a third party engineering company contracted by the project participants. The figure is calculated based on 51 years' worth of historical hydrological data and therefore the long term average annual power supplied is unlikely to be significantly different to the value used in the financial analysis. Assuming a 25% of increase in the long term average annual power supplied to the grid is not reasonable, and the IRR is therefore not likely to reach the 11.45% benchmark.

These results show that only under very unrealistic and highly favourable circumstances would it be possible to reach the Project IRR benchmark. We can conclude that the IRR is lower than the benchmark for a realistic range of assumptions for the key input parameters and therefore, that the Project is not financially attractive. This demonstrates that the project activity would not be implemented without the CDM.

Step 4: Common Practice Analysis:

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

According to the Guidelines on Common Practice (Version 01.0) approved in EB63 as annex 12 of meeting documents and Tool for the demonstration and assessment of additionality (Version 06.0.0), the common practice analysis is illustrated by following sub-steps.

Sub-step 4.1. Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.

Since the installed capacity of the proposed project activity is 108MW, and thus the +/-50% of the installed capacity of the proposed project activity, which is from 54MW to 162MW, is the applicable output range.

Sub-step 4.2. In the applicable geographical area, indentify all plants that deliver the same output or capacity, within the applicable output range calculated in Sub-step 4.1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}. Registered CDM project activities shall not be included in this step;

According the Guidelines, the applicable geographical area covers the entire host country as a default. Therefore, the N_{all} is the number of all the power plants within the applicable output range and starting commercial operation prior to 15th February 2011(i.e. the start date of the project) in Georgia, except the registered CDM project activities.

The table below provides the full list of power plants serving the electricity system of Georgia which are within the rage specified in sub Step 4.1.[7]

No	Power Plant	Start date	Type	Rated capacity, MW
1	Khrami-1	1947	Hydro	113
2	Gumathesi	1956	Hydro	67

[7] http://moe.gov.ge/index.php?lang_id=ENG&sec_id=123

3	Dzevrulhesi	1956	Hydro	60
4	Lajanurhesi	1960	Hydro	112
5	Khrami II	1963	Hydro	110
6	Tbilsresi	1965	Thermal	150
7	Zhinvalhesi	1985	Hydro	130
8	"Energy Invest" Gas turbine- 1	2006	Thermal	110

Sub-step 4.3. Within plants identified in sub-step 4.2, indentify those that apply technologies different that the technology applied in the proposed project activity. Note their number N_{diff}

Considering the facts that the non-renewable plants and captive plants enjoy different energy source/fuel, plants 6 and 8 are identified as applying different technology with the proposed project; thereby they will be included in the N_{diff}.

All the hydropower plants included in the N_{all} were built in the soviet time by the State when the sector was functioning not on the market basis. Additionally, the electricity sector in Georgia went through a fundamental reform between 1995-2000. The landmarks of this reform include:

- In 1995 the vertically integrated state owned company "Sakenergo" was divided into three parts: power transmission & dispatch, distribution and generation;
- In 1995 Ministry of Energy and Fuels was established
- In 1997 the Law on Electricity and Natural Gas was adopted;
- In 1997 the National Energy Regulatory Commission was formed
- In 2000 the Wholesale Electricity Market was formed;

Therefore, it is fair to say that energy projects implemented before 2000 did not take place in a 'comparable environment' with respect to regulatory framework or investment climate and cannot be deemed to be similar to the proposed project activity. Therefore projects 1, 2, 3, 4, 5 and 7 should be included in N_{diff}. Therefore N_{diff} *is 8.*

Sub-step 4. 4: Calculate factor "F" representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity. The factor F is calculated with the following equation.

$$F=1- (N_{all} / N_{diff})$$

The proposed project activity is a common practice within a sector in the applicable geographical area if the factor F is greater than 0.2 and $N_{all} – N_{diff}$ is greater than 3.

For the project activity: $F = 0$ and $N_{all} – N_{diff} = (8 – 8) = 0$

It is demonstrated that the proposed project activity is not a common practice in Georgia.

As a result of applying the "Tool for demonstration and assessment of additionality" it is concluded that based on conservative approaches and assumptions the proposed project activity fulfills all the additionality requirements demonstrating that the CDM registration is required and fundamental for its implementation.

B.6. Emission reductions

B.6.1. Explanation of methodological choices

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The procedures to determine the emission reductions attributable to the Project activity are described below, according to the selected approved methodology ACM0002 v.13.0.0 "*Consolidated baseline methodology for grid-connected electricity generation from renewable sources*".

Baseline emissions

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The methodology assumes that all project electricity generation would have been generated by existing grid-connected power plants and the addition of new grid-connected power plants. The baseline emissions are to be calculated as follows:

$$BE_y = EG_{PJ,y} \times EF_{grid,CM,y}$$

Where:

BE_y = Baseline emissions in year *y* (tCO_2/yr)

$EG_{PJ,y}$ = 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 year *y* (MWh/yr)

$EF_{grid,CM,y}$ = Combined margin CO_2 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*" (tCO_2/MWh)

Calculation of $EG_{PJ,y}$

If the project activity is the installation of a new grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity (Greenfield plant), then:

$$EG_{PJ,y} = EG_{facility,y}$$

Where:

$EG_{PJ,y}$ = 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 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)

Calculation of the combined margin CO_2 emission factor for grid connected power generation in year y ($EF_{grid,CM,y}$)

According to methodology ACM0002 version 13.0.0, $EF_{grid,CM,y}$ is calculated using the latest version of the "*Tool to calculate the emission factor for an electricity system*.

The combined margin emission factor ($EF_{CM,y}$) consists of the weighted average of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$), as d

According to the "*Tool to calculate the emission factor for an electricity system*", project participants shall apply the following six steps:

- STEP 1. Identify the relevant electricity systems.
- STEP 2. Choose whether to include off-grid power plants in the project electricity system (optional).
- STEP 3. Select a method to determine the operating margin (OM).
- STEP 4. Calculate the operating margin emission factor according to the selected method.
- STEP 5. Calculate the build margin emission factor.
- STEP 6. Calculate the combined margin (CM) emission factor.

Step 1: Identify the relevant electricity systems

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 to calculate the emission factor for an electricity system": *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[8]. This guidance from the DNA of Georgia been applied to determine the emission factor of Georgia.

There is no information about interconnected transmission capacity investments, so for BM calculation transmission capacity is not considered.

Step 2: Choose whether to include off-grid power plants in the project electricity system

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor.

- Option I: Only grid power plants are included in the calculation
- Option II: Both grid power plants and off-grid power plants are included in the calculation.

Since information from power generation is available for grid connected power plants, option I is chosen.

Step 3: Select a method to determine the operating margin (OM)

$EF_{grid,OM,y}$ should be calculated based on one of the four following methods:

(a) Simple operating margin, or
(b) Simple adjusted operating margin, or
(c) Dispatch Data Analysis operating margin, or
(d) Average operating margin.

[8] http://www.moe.gov.ge/files/Klimatis%20Cvlileba/Grid_Emission_Factor_Georgia.

Any of the four methods can be used, however, the simple OM method (option a) can only be used if low-cost/must-run resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

The Georgian electricity mix does not comprise nuclear energy. Also there is no obvious indication that coal is used as must run resources. Therefore, the only low cost resource in Georgia, which is also considered as must-run, is Hydro power plants. Electricity generation amount by resources from 2002 to 2006 is given in the table below[9].

Source	2002	2003	2004	2005	2006	Averaged
Generation from Hydro power plants						
(MWh)	6,652.10	6,420.70	5,893.10	5,920.30	5,292.90	6,035.80
Share, %	85.8	80.3	73.7	71.5	65.8	75.2
Generation from Thermal power plants						
(MWh)	467.9	587.9	813.2	958.4	2103.8	986.7
Share, %	6	7.4	10.2	11.6	25.7	12.2
Import	635.1	998.6	1,288.20	1,398.60	777	1,017.50
Share, %	8.2	12.4	16.1	16.9	9.5	12.6
Total (MWh)	**7,755.10**	**7,997.20**	**7,994.50**	**8,227.40**	**8,173.70**	**8,040.00**

As average share of low cost resources for the last five years is more than 50% (75.2%), the simple OM method is not applicable to calculate the operating margin emission factor (EFgrid,OM,y). Thus baseline emission factor was calculated using Simple adjusted OM method.

For the simple adjusted OM, the emissions factor can be calculated using either of the two following data vintages:

- Ex ante option: A 3-year generation weighted average, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation, without requirement to monitor and recalculate the emissions factor during the crediting period,

or

- Ex post option: The year in which the project activity displaces grid electricity, requiring the emissions factor to be updated annually during monitoring.

The ex-ante option is selected for Simple adjusted OM method, with the most recent data for the baseline calculation stemming from the years 2004 to 2006.

Step 4: Calculate the operating margin emission factor according to the selected method

The simple adjusted OM emission factor (EF grid,OM-adj,y) is a variation of the simple OM, where the power plants/units (including imports) are separated in low-cost/must-run power sources (k) and other power sources (m). As under Option A of the simple OM, it is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

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

9 http://www.moe.gov.ge/files/Klimatis%20Cvlileba/Grid_Emission_Factor_Georgia.

Where:

$EF_{grid,OM-adj,y}$	= 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 on the 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)
$NCV_{i,y}$	= Net calorific value (of fossil fuel type i in year y (GJ / mass or volume unit)
$EG_{EL,m,y}$	= CO2 emission factor of power unit m in year y (tCO 2 /MWh)
$EG_{EL,k,y}$	= CO2 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.

According to Tool, $EF_{EL,m,y}$, $EF_{EL,k,y}$, $EG_{m,y}$ 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.

Net electricity imports must be considered low-cost/must-run units k. Because low-cost/must run sources in Georgia are only Hydro PPs with zero emissions, second part of above formulation becomes 0 (zero). As also $EF_{EL,m,y}$ and $EG_{m,y}$ will be calculated in accordance with Simple OM, above formulation becomes:

$$EF_{grid,OM-adj,y} = (1-\lambda_y)\ x\ EF_{grid,OMsimple,y}$$

Option A - Calculation based on average efficiency and electricity generation of each plant

Under this option, the simple OM emission factor is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_m EG_{m,y} x EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,y}$	= Simple operating margin CO_2 emission factor in year y (tCO_2 /MWh)
$EG_{m,y}$	= Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)
$EF_{EL,m,y}$	= CO_2 emission factor of power unit m in year y (tCO_2/MWh)
m	= All power units serving the grid in year y except low-cost/must-run power units
y	= The relevant year as per the data vintage chosen in Step 3

In Georgia, there is only natural gas fired power plants and hydro power plants. As hydro power plants are considered as low-cost/must-run power units, only natural gas fired power plants are taken into account for calculation.

Determination of $EF_{EL,m,y}$

Option A1 is selected to determine the emission factor of each power unit *m*. According to this option, if for a power unit *m* data on fuel consumption and electricity generation is available, the emission factor ($EF_{EL,m,y}$) should be determined as follows:

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

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y (tCO2/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)
$EFCO_{2,i,y}$ = CO2 emission factor of fossil fuel type i in year y (tCO2/GJ)
EG_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
y = The relevant year as per the data vintage chosen in Step 3

Natural gas is the only fossil fuel consumed for the electricity generation in Georgia, therefore index *i* is cancelled. $NCV_{i,y}$ values were provided by the Ministry of Energy of Georgia. For $EF_{CO2,i,y}$ there is no plant specific, or national values. Therefore, IPCC default value at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories, is used for natural gas fired power units. This factor is 54.3 tCO2 /TJ.

Determination of $EG_{m,y}$

For grid power plants, $EG_{m,y}$ should be determined as per the provisions in the monitoring tables. As ex-ante option is chosen, most recent three historical years for which data is available at the time of submission of the CDM-PDD to the DOE for validation, shall be used. As available electricity generation amount for each power units *m* is for the years between 2004-2006, these values are used in the calculation. According to Tool, net electricity imports must be considered low-cost/must-run units k. Therefore, electricity import amounts are not included in $EG_{m,y}$ calculation.

Table 2: Natural gas consumption (thousand m^3), natural gas calorific value and other parameters used in calculations and calculated COEF for years 2004-2006

Plant	j	2004	2005	2006
		$F_{i,y}$ – Natural gas consumption, Thousand m^3		
Tbilsresi	*1*	9,755	108,909	248,731
AES Mtkvari	*2*	248,873	206,712	349,820
"Energy Invest" Gas-turbine-1	*3*	-	-	91,675
Total	*t*	258,628	315,621	690,227
NCV, kcal/m³		8,039	8,041	8,045
NCV, Tj/1000 m³		0.033658	0.033668	0.033682
EF_C, t C /Tj		15.3	15.3	15.3
EF_{CO2}, t CO_2/Tj		56.1	56.1	56.1
Oxidation factor – OXID		1	1	1
COEF, tCO_2/1000 m^3		**1.888**	**1.889**	**1.890**

For natural gas oxidation factor (*OXID*) and the CO_2 emission factor per unit of energy (EF_C) IPCC default values were used, particularly *OXID*=1.0 and EF_C =15.3 t C/Tj

Electricity delivered from other than low-cost/must run sources (thermal power plants) to the electricity system of Georgia, CO 2 emissions and estimated Simple OM emission factors ($EF_{\text{Simple OM}}$) for years 2004-2006 are shown in the table below.

y Year	j Source	$EG_{m,y}$ – Delivered electricity, GWh	Emissions, tCO_2	$EF_{CO2,j,y}$ Emission factor tCO_2/MWh	$EF_{grid,OMsimple,y}$ tCO_2/MWh
2004	Tbilsresi	21.5	18,419	0.8578	**0.6005**
	AES Mtkvari	791.7	469,921	0.5935	
	Total	**813.2**	**488,340**	**0.6005**	
2005	Tbilsresi	292.1	205,704	0.7042	**0.6220**
	AES Mtkvari	566.3	390,431	0.5859	
	Total	**958.4**	**596,136**	**0.6220**	
2006	Tbilsresi	563.9	439,624	0.6622	**0.6055**
	AES Mtkvari	1,149.4	660,999	0.5751	
	"Energy Invest" Gas-turbine-1	290.4	173,231	0.5964	
	Total	**2,103.8**	**1,273, 849**	**0.6055**	

λ parameter was calculated as λ = X / T, where X is the number of hours for which low-cost/must-run sources are on the margin, T is number of hours in year. Lambda (λ y) should be calculated as follows:

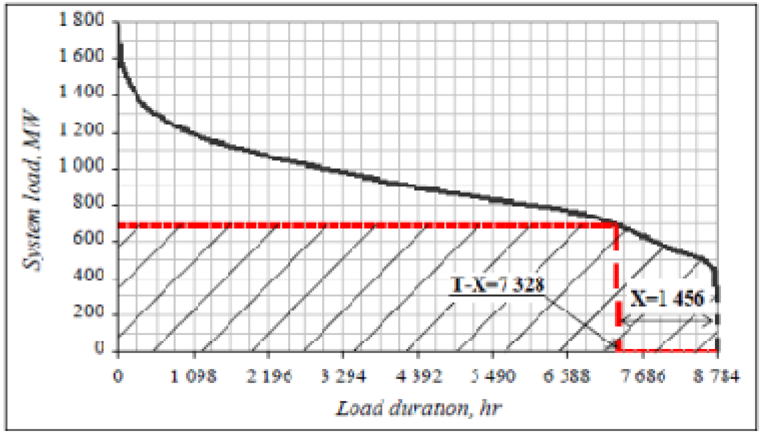
Step (i) **Plot a load duration curve**. Chronological load data for each hour of year for electricity system of Georgia were ranked from highest to lowest and load duration curves were plotted for years 2004-2006 (see Figures 1-3). Revised data (excel spreadsheets) were provided by the Ministry of Energy of Georgia.

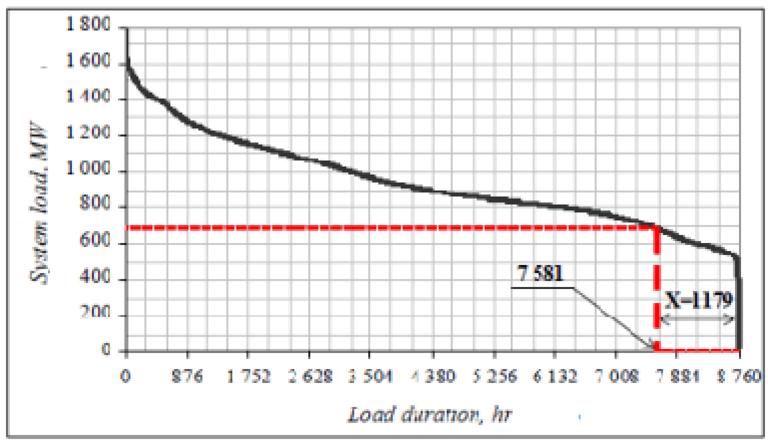
Step (ii) **Organize Data by Generation Sources**: Revised data for annual generation (in MWh) from low-cost/must run resources (HPPs) have been collected and total annual generation from low-cost/must run resources (i.e. $\Sigma_k EG_{k,y}$) have been calculated. Relevant revised data (excel spreadsheets) were provided by the Ministry of Energy of Georgia as stated in the study of Georgian DNA.

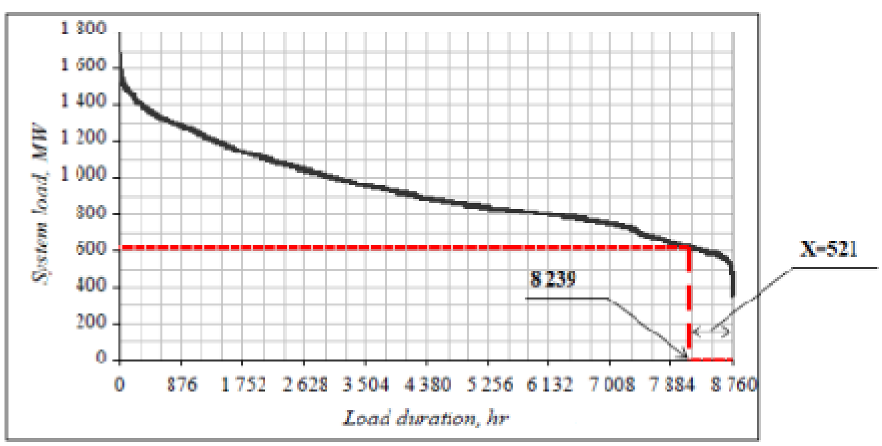
Step (iii) **Fill the load duration curve**. A horizontal line across the load duration curve was plotted such that the area under the curve (as an illustration dashed area on Figure 4) equals the total generation (in MWh) from lowcost/must-run power plants/units (i.e. $\Sigma_k EG_{k,y}$).

Step (iv) **Determine the "Number of hours for which low-cost/must-run sources are on the margin in year y"** First, the intersection of the horizontal line plotted in step (iii) and the load duration curve plotted in step (i) was located. The number of hours (out of the total of 8760 hours) to the right of the intersection is the number of hours for which low-cost/must-run sources are on the margin. If the lines do not intersect, then one may conclude that low cost/must-run sources do not appear on the margin and λy is equal to zero.

Lambda (λ_y) is the calculated number of hours divided by 8760 (in leap-year by 8784). Relevant diagrams for years 2004-2006 are given on the Figures below.







Calculation of λ and Operating Margin emission factor is given in table below.

Parameter	2004	2005	2006	Generation weighted
Generation (MWh)	6,706,310	6,878,741	7,396,739	
X, hours	1456	1179	521	
λ	0.166	0.135	0.059	
$1-\lambda$	0.834	0.865	0.941	
$EF_{Simple\,OM}$, tCO_2/MWh	0.60051	0.62200	0.60550	
$EF_{Adjusted\,Simple\,OM,y}$ tCO_2/MWh	**0.50097**	**0.53829**	**0.56949**	**0.53736**

EF $_{Simple\ Adjusted\ OM,\ y}$ = (6,706,310 • 0.60051+6,878,741 • 0.62200+7,396,739 • 0.60550)/ (6,706,310+6,878,741+7,396,739)=**0.53736 tCO_2/MWh**

Step5. Calculate the Build Margin emission factor ($EF_{BM,y}$).

The build margin emissions factor is the generation-weighted average emission factor (tCO_2 /MWh) of all power units *m* during the most recent year y for which electricity generation data is available, calculated as follows:

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

Where:

EF *grid,BM,y* = Build margin CO 2 emission factor in year y (tCO 2 /MWh)
EG *m,y* = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
EF *EL,m,y* = CO 2 emission factor of power unit m in year y (tCO 2 /MWh)
m = Power units included in the build margin
y = Most recent historical year for which electricity generation data is available

To calculate EF $_{BM,y}$ ex-ante version was used.

Power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently are given in the table below.

According to this table generation of the five power plants that have been built most recently is less than 20%. AES Mtkvari is fully included in calculations. There are not in Georgia power units registered in the CDM.

No	Source	Start up date	Delivered electricity, MWh		Share, %		Emissions,
			Actual	Accumulated		Accumulated	tCO_2
35	AES Mtkvari	1990	1,149,449	1,594,092	15.54	21.55	660,999
37	Imsobahesi	1993	2,265	444,643	0.03	6.01	
38	JSC "Kindzmarauli"	2001	2,561	442,378	0.03	5.98	
39	Munleik-Georgia	2002	22,172	439,817	0.30	5.95	
40	Khadorhesi	2004	127,201	417,645	1.72	5.65	
41	"Energy Invest" Gas-turbine 1	2006	290,444	290,444	3.93	3.93	173,226
	Total		**1,594,092**				**834,225**

According to formula (7): Build margin Emission Factor =**0.52332 (=834,225/ 1,594,092)** tCO 2 /MWh

Calculate Baseline emission factor.

As mentioned above baseline Emission factor was calculated by formula:

$EF_{Baseline} = w_{OM} \times EF_{Operating\ Margin} + w_{BM} \times EF_{Build\ Margin}$

According to the "Tool to calculate the emission factor for an electricity system" the default values are: $w_{OM} = w_{BM} = 0{,}5$.

$EF_{Baseline}$ = 0,5 x (0.27657 +0.52332) tCO_2 /MWh = **0.53034 tCO_2 /MWh.**

Project emissions

The power density Pof the project is 43 200W/m2, which is more than 10 W/m2. According to ACM0002, the project emissions from water reservoirs of hydro power plants are zero.

Therefore, $PE_y = 0$

Leakage

According to ACM0002 (Version 13.0.0), no leakage emissions are considered, therefore: LE_y=0.

Emission reductions

Emission reductions are calculated as follows:

ER y = BE y – PE y

Where:
ER y = Emission reductions in year y (t CO 2 e/y);
BE y = Baseline emissions in year y (t CO 2 e/y);
PE y = Project emissions in year y (t CO 2 /y).

As no project emissions were identified for this project, ER y = BE y .

Then, ER y = EG ,facility,y x EF grid,CM,y

B.6.2. Data and parameters fixed ex ante

Data / Parameter	$EF_{grid, CM,y}$
Unit	tCO_2/MWh
Description	Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the "*Tool to calculate the emission factor for an electricity system"*.
Source of data	Grid Emission Factor Study of Ministry of Environment Protection and Natural Resources of Georgia (DNA of Georgia) based on information submitted by Ministry of Energy of Georgia
Value(s) applied	**0.53034** tCO_2/MWh
Choice of data or Measurement methods and procedures	Calculation as per the "*Tool to calculate the emission factor for an electricity system*" .
Purpose of data	
Additional comment	

Data / Parameter	$FC_{i,m,y}$
Unit	Mass or unit volume
Description	Amount of fuel *i* (in mass or volume unit) consumed by each power plant / unit in the Grid
Source of data	Grid Emission Factor Study of Ministry of Environment Protection and Natural Resources of Georgia (DNA of Georgia) based on information submitted by Ministry of Energy of Georgia
Value(s) applied	See above
Choice of data or Measurement methods and procedures	Official statistical data
Purpose of data	
Additional comment	

Data / Parameter	$EG_{m,y}$, EG_{y} , $EG_{k,y}$
Unit	MWh/year
Description	Net electricity generated and delivered to the grid by each power plant / unit
Source of data	Baseline Emission Factor for the Electricity System of Georgia developed by the Ministry of Environment Protection of Georgia CDM DNA
Value(s) applied	See above
Choice of data or Measurement methods and procedures	Official statistical data
Purpose of data	
Additional comment	

Data / Parameter	**NCV i,y**
Unit	GJ/t
Description	Net calorific value (energy content) per mass unit of bunker
Source of data	Grid Emission Factor Study of Ministry of Environment Protection and Natural Resources of Georgia (DNA of Georgia) based on information submitted by Ministry of Energy of Georgia
Value(s) applied	See above
Choice of data or Measurement methods and procedures	Values have been adopted as they refer to national official data (national average default values). This is in line with the “Tool to calculate the emission factor for an electricity system”
Purpose of data	
Additional comment	

Data / Parameter	$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$
Unit	CO_2/TJ
Description	CO_2 emission factor per unit of energy of diesel
Source of data	IPCC. 2006. Guidelines for National Green House Gas Inventories.
Value(s) applied	See above
Choice of data or Measurement methods and procedures	IPCC default value
Purpose of data	
Additional comment	

B.6.3. Ex ante calculation of emission reductions

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As indicated in section B.6.1, the formula used to calculate the emission reductions are:

$ER_{y} = EG_{facility,y} \text{ x } EF_{grid,CM,y}$

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

In order to estimate the ex ante emission reductions for the first crediting period, estimated figures were used for parameters that are unavailable during validation or that are monitored during the crediting period.

$EG_{facility,y}$ = 505,000 MWh

$EF_{grid,OM\text{-}adj, 2004,2005,2006}$ = 0.53736 tCO_2 /MWh

$EF_{grid,BM,2007}$ = 0.52332 tCO_2 /MWh

The default weights are as follows: w OM = 0.5 and w BM = 0.5, for the first crediting period. Therefore:

$EF_{grid, CM,2005,2006,2007}$ == 0.53034 tCO_2 /MWh

Therefore, for the first crediting period, the emission reductions are estimated for a year y, as follows:

ER y = 505 000 * 0.53034 = 267 821 (in tCO 2 e)

For more detailed information, see section B.6.1.

B.6.4. Summary of ex ante estimates of emission reductions

Year	**Baseline emissions (t CO_2e)**	**Project emissions (t CO_2e)**	**Leakage (t CO_2e)**	**Emission reductions (t CO_2e)**
Year 2015	267,821	0	0	267,821
Year 2016	267,821	0	0	267,821
Year 2017	267,821	0	0	267,821
Year 2018	267,821	0	0	267,821
Year 2019	267,821	0	0	267,821
Year 2020	267,821	0	0	267,821
Year 2021	267,821	0	0	267,821
Year 2022	267,821	0	0	267,821
Year 2023	267,821	0	0	267,821
Year 2024	267,821	0	0	267,821
Total	2,678,217	**0**	**0**	**2,678,210**
Total number of crediting years	10			
Annual average over the crediting	267,821	0	0	267,821

period				

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

Data / Parameter	$EG_{facility,y}$
Unit	**MWh/yr**
Description	Quantity of net electricity generation supplied by the project plant to the grid in year y
Source of data	Electricity meter
Value(s) applied	505 000 MWh
Measurement methods and procedures	The following parameters will be measured: (i) The quantity of electricity supplied by the project plant/unit to the grid; and (ii) The quantity of electricity delivered to the project plant/unit from the grid
Monitoring frequency	Continuous measurement and monthly recording
QA/QC procedures	The accuracy of the electricity meter(s) measuring electricity supplied to the grid will be in accordance with national requirements; The electricity meter(s) measuring electricity supplied to the grid will be calibrated according to the relevant national requirements; Data measured by the meter(s) will be cross-checked against records for sold electricity.
Purpose of data	
Additional comment	

Data / Parameter	Cap_{PJ}
Unit	**W**
Description	Installed capacity of the hydro power plant after the implementation of the project activity.
Source of data	Feasibility Study Report.
Value(s) applied	108 MW
Measurement methods and procedures	The installed capacity of the hydro power plant will be recorded annually based on the nameplates of the installed equipment.
Monitoring frequency	
QA/QC procedures	
Purpose of data	
Additional comment	

Data / Parameter	A_{PJ}
Unit	m^2
Description	Area of the reservoir measured on the surface of the water, after the implementation of the project activity, when the reservoir is full.
Source of data	Feasibility Study Report
Value(s) applied	0.25 ha
Measurement methods and procedures	The area of the reservoir has been determined on the basis of the Project Design and will be measured from topographical surveys, maps or satellite pictures.
Monitoring frequency	Yearly
QA/QC procedures	
Purpose of data	
Additional comment	Archived data will be retained during the crediting period.

B.7.2. Sampling plan

>>

NA

B.7.3. Other elements of monitoring plan

>>

This section details the steps taken to monitor the GHG emissions reductions on a regular basis from Dariali Hydroelectric Power project in the Georgia.

The monitoring set-up for this Project has been developed to ensure that from the start, the Project is well-organised in terms of the collection and archiving of complete and reliable data.

1. CDM monitoring Organisation

Roles and responsibilities will be defined for relevant staff involved in CDM monitoring, and the prospect of nominating a CDM Manager will be considered. If appointed, the CDM Manager will have the overall responsibility for the monitoring system on this project. All staff involved in the collection of data and records will be coordinated by him.

2. Staff training

Training is conducted on-site to ensure that staff are capable of performing their designated tasks to high standards. This will include CDM specific training to warrant that they understand the importance of complete and accurate data and records for CDM monitoring.

3. Maintenance and calibration of monitoring equipment

The electricity meter(s) measuring electricity supplied to the grid will be calibrated in line with the relevant national requirements. This will ensure that the equipment operates at the stated level of accuracy.

4. Data collection and record-keeping arrangements

All CDM relevant data will be measured and collected as detailed in Section B.7.1. All data required for verification and issuance will be backed-up and retained for at least two years after the end of the crediting period or the last issuance of CERs of the Project, whichever occurs later.

Data collected on-site will be compiled in an electronic format which will be sent to carbon Consultant on a regular basis.

5. Data Quality Control and Quality Assurance
All data collected on-site will be checked internally before being compiled in an electronic format, to ensure that it is complete and of appropriate quality. The Carbon Consultant will perform a final check of the data, and analyse project performance prior to any verification.

SECTION C. Duration and crediting period
C.1. Duration of project activity
C.1.1. Start date of project activity
>>
12/02/2012
C.1.2. Expected operational lifetime of project activity
>>
20 years

C.2. Crediting period of project activity
C.2.1. Type of crediting period
>>
Fixed

C.2.2. Start date of crediting period
>>
The crediting period will begin on 01/02/2015 (proposed date of starting operation), or on the date of registration of the CDM project activity, whichever is later.

C.2.3. Length of crediting period
10 years

SECTION D. Environmental impacts
D.1. Analysis of environmental impacts
>>
Environmental impact assessment for the Dariali HEP has been conducted in accordance with Georgian law by the Scientific Research Firm Gamma of Tbilisi in cooperation with Stucky of Switzerland and approved by Ministry of Environmental Protection of Georgia on 28th of November 2011[10] . A summary of the analysis of the environmental impacts is provided in section D.2. below.

D.2. Environmental impact assessment
>>
A Summary of the analysis of the environmental impacts of the project activity is provided at the Project's Environmental and Social Impact Assessment Report. According to the Report no significant environmental impact is foreseen during construction and operation phases of HPP, for the following reasons:

- Construction of low level, small dam and lateral water intakes is planned at the headwork's. They will ensure full downstream passage to surplus water and solid sediments. Therefore there is a minimum risk to negatively impact on hydrology and bank stability of Tergi River

[10] Decision Number 29

- fish passes and fish protection structure at each headwork is considered to be constructed to minimize negative impact on ichtyofauna;
- Structure of the head works requires arrangement of only small size stagnation in headrace of the dam, which prevents negative impact on regional climate and meteorological conditions and significantly reduces geohazard risks;
- According to the project, each headwork should ensure environment flow (10% of 95% average multiannual flow), which (in some hundred meters from the dam river Tergi connects to the river Kuro, small tributaries and afterwards river Devdokari) will create some definite conditions for Tergi River ichthyofauna;
- Majority of HPP communications: derivation pipeline, diversion tunnel, power house, tailrace channel will be arranged underground which together with recultivation works significantly reduces impact on regional bio-environment as well as on visual-landscape impact risks;
- Considerable amount (approximately 60%) of waste rock produced during HPP construction phase will be used during HPP infrastructure construction (as construction material). Main part of waste rock will be stored on right side of the riv.Tergi with purpose to use them during construction phase of "Larsi HPP" diversion pipeline; unused waste rock will be used for maintenance of local Municipality roads.
- Construction site will be arranged on the territory free from any planting; after completion of works, project considers recultivation works of the used territory; no significant bioenvironment impact is anticipated;
- Considering that construction works will be held on a big distance from settlements, impact from air quality deterioration will be insignificant;
- According to the estimations given in the report noise impact will be insignificant during construction and operation phases. Certain impact on fauna is anticipated; however, this disturbance will be short-term and disturbed specimens should return to their native habitats post construction;
- In case of purposeful environmental management and fulfilment of designed mitigation measures impact on aquatic environment should not be significant on construction or operation phases;
- Due to reasonable distance between power transmission lines and residential zones no measures are needed to mitigate impact of electric field.
- Considering that construction site will be located on a big distance from settlements and that traffic routed selected for transportation (only military road of Georgia will be used for transportation purposes) no increase of traffic flows are expected;
- Only state and municipal lands will be used during HPP construction-operation phase; so there is no risks of losing property with this regard;
- Considering planned mitigation measures during HPP construction and operation phase, trans-boundary and cumulative impact will not be significant;
- The HPP implementation project will cause positive impacts, such as:
    - On the construction and operation phases local population will be employed for a number of temporary and later permanent jobs at the HPP infrastructure, which is extremely important for local population employment; (as per social policy of "Darial Energy" 80% on low qualification working places employed staff will be local)
    - The HPP construction and operation project includes rehabilitation of local roads which should be assumed as a positive impact on local population;
    - The HPP construction and operation project will positively affect Kazbegi Municipality as well as socio-economic development of Mtskheta-Mtianeti region.

Some impacts are expected mainly at the construction phase. This includes:

- Considerable anthropogenic load due to construction works will cause serious impact on local wildlife. Though it is noteworthy that the impact will be a short-term and faunal specimen will return to their habitats post construction;
- Some significant impact is anticipated due to fragmentation of habitats due to construction of derivation canal and access roads, which may be lessened with corresponding mitigation measures, namely: completion of civil works in short period of time; arrange temporary crossings above pipeline channel during construction period;
- The HPP construction may hinder free transportation of population and some agricultural activities; but this will be a short-term impact which will last till completion of civil works.
- Anticipated hydrological changes (lack of water) in the riverbed of Tergi river in tailrace of the dam during HPP operation phase can be assumed as significant impact as well as permanent negative impact on ichthyofauna of the river.

Mitigation actions have been identified in order to minimise the impact.

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

>>

Dariali has conducted a stakeholder consultation on its website and in the national press. Stakeholders were informed about the programme through specific adverts published by the Project Developer in local newspapers on 26/7/2012. The advert invited stakeholders to comment and to seek further information on the project on the Project development website. The period for comments was open for 1 month from the date of the adverts.

E.2. Summary of comments received

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To date no comments have been received.

E.3. Report on consideration of comments received

>>

Not applicable as no comments have been received

SECTION F. Approval and authorization

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No letter(s) of approval from the Party involved in the Project are available at the time of submitting the PDD to the validating DOE. Project participants will request relevant approval in parallel with the validation process.

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Appendix 1: Contact information of project participants

Organization name	Joint Stock Company Dariali Energy
Street/P.O. Box	4 Besiki str.,
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City	Tbilisi
State/Region	
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Direct fax	
Direct tel.	+995322 510500
Personal e-mail	p.janelidze@darialienergy.ge

Appendix 2: Affirmation regarding public funding

The proposed project will not receive any public funding from Parties included in Annex I of the UNFCCC

Appendix 3: Applicability of selected methodology

Appendix 4: Further background information on ex ante calculation of emission reductions

Please see part II section B6.1 for an explanation of the methodological choices, including the grid emission factor calculations.

The supporting spread sheet where the carbon emission factor for grid-based electricity is calculated has been provided as a separate document to the validator

Appendix 5: Further background information on monitoring plan

No additional information other than given in B.7 above

Appendix 6: Summary of post registration changes

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History of the document

Version	Date	Nature of revision
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	EB 66 13 March 2012	Revision required to ensure consistency with the "Guidelines for completing the project design document form for CDM project activities" (EB 66, Annex 8).
03	EB 25, Annex 15 26 July 2006	
02	EB 14, Annex 06b 14 June 2004	
01	EB 05, Paragraph 12 03 August 2002	Initial adoption.

Decision Class: Regulatory
Document Type: Form
Business Function: Registration