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

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	24 MW Dummagudem Hydel project by SLS Power Corporation Limited
Version number of the PDD	Version ~~4~~5
Completion date of the PDD	~~09/10/2011~~ 15/12/2013
Project participant(s)	M/s SLS Power Corporation Limited
Host Party(ies)	India
Sectoral scope and selected methodology(ies)	Reference: Scope 1, Energy Industries Version 11 – Approved consolidated baseline and monitoring methodology ACM0002 “Consolidated baseline methodology for grid-connected electricity generation from renewable sources”, EB 52
Estimated amount of annual average GHG emission reductions	89,267 tCO_2e

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

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The 24 MW Dummagudem hydro project of SLS Power Corporation Limited is a grid connected run-of-river hydro power project located in Andhra Pradesh, India. The proposed project is located in the Southern Power Region and has been conceived for harnessing the power potential of left flank of the branch anicut in the Godavari River in Khammam District. This project involves the installation of six Horizontal Pit type full Kaplan turbines & generating units of 4 MW each to generate 24MW of power utilizing a rated head of 4.8m and a design discharge of 601.02m^3 (Please refer to section A.4.3 for further technical details).

The project activity is a Greenfield project planned on the Godavari River. Thus, the scenario existing prior to the implementation of this project activity would be to allow the potential energy in the flowing river to go untapped. In the absence of the project activity, any existing power demand in the region would be met by the continued operation of fossil fuel based power plants in the grid. Hydropower is a clean, renewable source of energy and does not contribute to air or water pollution or the emissions of greenhouse gases. The water after powering the turbines will be discharged back into the Godavari River through a tailrace canal, located within the river course close to the left bank open channel.

The objective of the proposed project is to generate power from harnessing the water to meet the ever increasing demand for electricity in the Southern region of India. The generated power will be exported to the Southern regional grid via the sub-station at Bhadrachalam. The project is expected to export 100,300 MWh of energy per year to the grid. Hydro power plants are considered to be zero emission power sources. The project activity will displace the fossil fuel fired power generation from the grid and hence contribute to a reduction in greenhouse gases.

As determined in Section B.4, the baseline scenario relates to the export of electricity to the grid by the operation of grid connected power plants and by the addition of new generation sources. The baseline scenario is the same as the scenario existing prior to the start of the implementation of the project activity.

Contribution of the project activity to Sustainable Development

The project is a run-of-river hydroelectric plant & hence does not involve the construction of a dam, therefore the negative impacts often associated with dams such as the relocation of communities and residents as well as transfer of waterways will not occur.

Locally, the project will contribute significantly to the social and economic situation of the local residents through creation of employment opportunities during the construction of the power plant besides providing regular employment opportunities during the operation of the project.

The project activity improves the connectivity of the project area, since it will result in the construction of additional roads and other infrastructure developments by spending around INR 18 Lakhs (2% of the

expected CER revenue, as per MOEF guidelines)[1] as part of the local area development assistance annually.

Contribution of the project activity to the Environment

The proposed project activity utilizes available hydro sources for power generation. The state of Andhra Pradesh is part of Southern regional grid system and power generation in the Southern Grid is dominated by fossil fuels. The project activity will not result in any greenhouse gas emissions and causes no negative impacts on the environment, both at a local as well as at a global level. The project activity does not result in degradation of any natural resources, health standards, etc. at the project area. The project will not cause any air, water, or noise pollution.

Contribution of the project activity to Technological Well Being

The project would utilize environmentally safe and sound technologies available in the hydroelectric power generation sector.

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

A.2.2. Region/State/Province etc.
>>
Andhra Pradesh

A.2.3. City/Town/Community etc.
>>
Dummagudem village, Bhadrachalam Taluka ,Khammam District

A.2.4. Physical/Geographical location
>>
project site from:

State Capital, Hyderabad: 378km
District headquarter, Khammam: 160km
Nearest railhead, Kottagudem: 62km

The geographical co-ordinates of the project site are:

Longitude: 80^0 53’ 12” E
Latitude: 17^0 51’ 19” N

The maps below show the exact location of the project activity in the state of Andhra Pradesh in India.

[1] Refer Appendix I of the PDD

Figure 1: Location of the Project Activity

A.3. Technologies and/or measures

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The project is a Greenfield project and hence, no equipments/systems would be in operation prior to the implementation of the project activity. The potential energy available within the Godavari river flow would remain untapped. The proposed project is a run-of-river hydro electric power plant with a design discharge of rated head of 4.8m and a design discharge of 601.02 cumecs. The hydro power plant has an installed capacity of 24 MW (6 x 4 MW each) and is capable of producing 103,400 MWh of power per year in a 90% dependable year with 95% machine availability and operating at a plant load factor of 49.18%. The catchment area at the diversion site is 307 km^2.

The salient features of the project are:

Table 1: Technical Parameters of Project activity

Parameter	**Value**
Net head	4.8m
Type of power house	Surface
Design discharge	600 Cumecs
Type of switchgear	11/132kV air insulated switchgear
Speed of turbine	111 rpm
Generation voltage	11kV
Transmission voltage	132kV
GSU transformer	20MVA 3 phase, 11/132 kV

The main components of the project are:

- A 100m wide gated weir
- An intake located at the axis of branch anicut
- One de silting basin
- A head race channel is located on the existing navigational channel
- Six (9.5 m x 10.5 m each) intake gate opening is provided for flow of water to turbines
- A surface power house to house six horizontal pit type full Kaplan units of 4MW each
- A tail race channel with a reverse slope and then with gradient up to 550 m that will discharge into the river in the direction of the river flow
- A surface switchyard 70m x 30m which shall house the generator transformer bays and an outgoing line
- 11 / 132 kV SC line from the site to Bhadrachalam to Etapaka Sub-Station (20 Kms)for evacuation of power

The turbine characteristics would be selected such that the optimum efficiency falls close to the rated output of the unit at rated head. A pumping station will be provided to supply an adequate quantity of water from the tailrace only for cooling of the turbine generator bearings, generator air coolers and selected plant services. It will then flow back into the river.

Each synchronous generator would be horizontal shaft, salient pole type, 3 phase, 50Hz directly coupled to the turbine. It would be rated for a continuous output of 4000 kW at a power factor of 0.85 and a rated voltage of 11kV with the capability of 10% intermittent overloading.

The power from the proposed project activity has been planned to be pooled at the proposed 132kV Etapaka (Bhadrachalam) sub-station. The Bhadrachalam sub-station in turn is hooked to the grid. The line length shall be about 20kms. Thus, the project activity will supply renewable energy to the Southern grid of India (grid identification undertaken in section B.4), thereby partly replacing the energy generated by other, fossil fuel based plants connected to the grid.

In the absence of the project activity the power in the grid would have been supplied by other grid connected power plants and addition of new power plants. The baseline scenario is the same as the scenario existing prior to the start of the implementation of the project activity.

Thus, the technology to be involved will be environmentally safe and sound technology.

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)
India (host)	M/s. SLS Power Corporation Limited	No

A.5. Public funding of project activity

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No Public Funding or funding from Annex 1 or ODA is involved in the project activity.

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

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Version 11 – Approved consolidated baseline and monitoring methodology ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources", EB 52

Version 2 – Tool to calculate the emission factor for an electricity system, EB 50

Version 2 - Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion, EB 41

Version 5.2 – Tool for the demonstration and assessment of additionality, EB 39, Annex 10

B.2. Applicability of methodology

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Table 4. Applicability of methodology

Methodology	Applicability Criteria	Project Status
ACM 0002 "Consolidated baseline	*The project activity is the installation capacity addition, retrofit or replacement of a power plant/unit of one of the*	The project activity will displace fossil fuel dominated electricity generation in Southern Grid by

methodology for grid-connected electricity generation from renewable sources”	*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.*	renewable source i.e., Hydro based power generation. Hence, the proposed project activity meets applicability criterion.
	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 10 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;*	Proposed project activity is Greenfield Hydro power project. Therefore criterion is not applicable.
	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.* • *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/m^2*.* • *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/m^2*.*	The project activity is a run of river project and does not result in a new reservoir. Thus, the project is applicable.

Conclusion:

The project activity is a renewable energy based power generation which will export generated power to the Southern grid of India. The geographic and system boundaries for the relevant electricity grids are

clearly identified therefore the project activity matches the applicability criteria of the methodology ACM0002/Version 11 (EB 52).

B.3. Project boundary

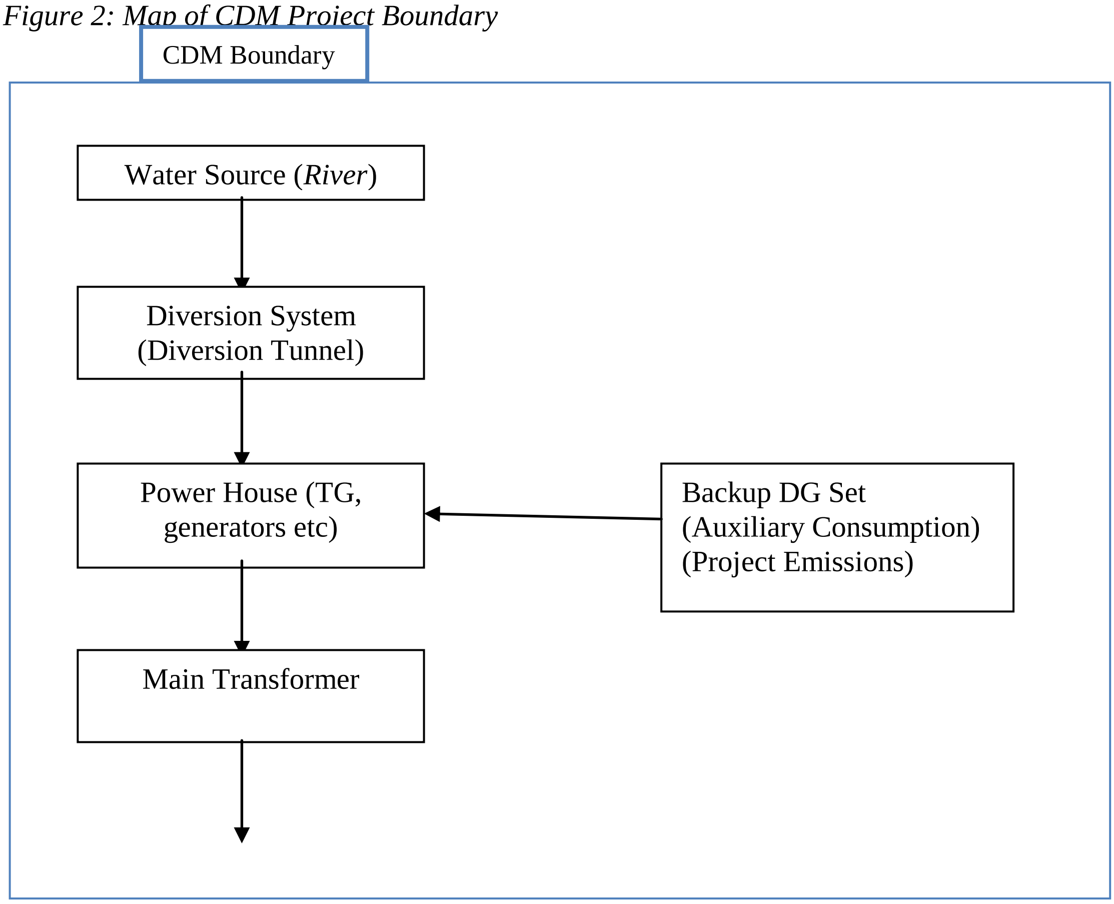
The methodology states – "*The spatial extent of the project boundary includes the project power plant and all power plants connected physically to the electricity system that the CDM project power plant is connected to.*"

In case of the project activity the project boundary thus includes the project hydro power plant and all the other power plants connected to the Southern Regional grid of India.
The electricity system is defined according to the *"Tool to calculate the emission factor for an electricity system version 2".*

For the purpose of the project activity the relevant grid is defined by the power generating units serving the same grid as the project activity. In the case of India there are regional grids which facilitate the transfer of electricity between states and which are supplied by central sector power stations operating in the region. Andhra Pradesh is part of the Southern Region and we have therefore considered the Southern grid.

The below flow diagram physically delineates the project activity and its relevant information:

Figure 2: Map of CDM Project Boundary



Electricity to Grid

The greenhouse gases and emission sources included in or excluded from the project boundary are shown in the table below:

Table 5: Sources & gases included in project activity

<table>
<tr><th colspan="2">Source</th><th>Gas</th><th>Included?</th><th>Justification/ Explanation</th></tr>
<tr><td rowspan="3">BASELINE</td><td rowspan="3">CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity.</td><td>CO2</td><td>Yes</td><td>This gas is included in the project boundary as this was produced in the baseline by the operation of fossil fuel fired power plants connected to the grid.</td></tr>
<tr><td>CH4</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td>N2O</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td rowspan="9">PROJECT ACTIVITY</td><td rowspan="3">For geothermal power plants, fugitive emissions of CH_4 and CO_2 from non condensable gases contained in geothermal steam.</td><td>CO2</td><td>No</td><td>The project activity is not a geothermal power plant and hence this is automatically excluded.</td></tr>
<tr><td>CH4</td><td>No</td><td>The project activity is not a geothermal power plant and hence this is automatically excluded.</td></tr>
<tr><td>N2O</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td rowspan="3">CO_2 emissions from combustion of fossil fuels for electricity generation in solar thermal power plants and geothermal power plants</td><td>CO2</td><td>Yes</td><td>The project activity is not a geothermal power plant or a solar thermal power plant. However, any usage of fossil fuels on site will be monitored and project emissions due to the same will be accounted for.</td></tr>
<tr><td>CH4</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td>N2O</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td rowspan="3">For hydro power plants, emissions of CH_4 from the reservoir</td><td>CO2</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
<tr><td>CH4</td><td>No</td><td>The project activity is a run of the river hydro project & does not result in a new reservoir. Hence, these emissions are neglected in line with the methodology.</td></tr>
<tr><td>N2O</td><td>No</td><td>The methodology considers this as a minor emission source and hence has been excluded for simplification.</td></tr>
</table>

B.4. Establishment and description of baseline scenario

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Since the project activity is the installation of a new grid-connected renewable power plant/unit, 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".

The baseline scenario of the project activity has been identified as per the guidance provided in step 1 of ACM0002 version 11, as shown below:

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 generated under the project would be generated in existing and new grid-connected power plants in the electricity system; and

P3: 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.

P1 – The investment analysis in Section B.5 shows that **P1** cannot be a credible baseline scenario since the proposed project faces hurdles that would prevent its implementation without the infusion of CDM benefits.

P2 – This is the most plausible baseline scenario since the grid is likely to continue generating the additional electricity that would be generated under the project (using a majority of fossil fuel fired plants) and does not face similar barriers to the project activity.

The table below highlights the power scenario in the state of Andhra Pradesh (AP)[2]:

Table 6: Installed Capacity in AP (as on 31st March 2010)

Power Plant Capacities	
Source	**Installed Capacity(MW)**
Thermal	4592.50
Hydel	3790.4
Others	2.00
Total	**8384.9**

[2] http://www.apgenco.gov.in/inner.asp?frm=ourpowerplants

The installed capacity in the state stands at 8384.9 MW, out of which hydro contributes 3790.4 MW (**45.20%**). However, due to the low Plant Load Factor of Hydro plants, the actual generation (in MWh) from these plants is much lower than thermal power plants as shown in the tables below.

Table 7: Generation from thermal plants[3]:

Year	Generation (MWh)
2009-10	26567000.6
2008-09	25677000.9
2007-08	23686000

Table 8: Generation from hydro plants[4]:

Station	Generation (MWh)		
	2008-09	**2009-10**	**2010-11**
Donkarayi Canal Power House (1 x 25 MW)	128000.2	41000.69	0000
Lower Sileru Hydro Electirc Scheme (4 x 115 MW)	1374000.3	632000.39	0000
Machkund Hydro Electric (Joint) Scheme (3 x 17 + 3 x 23) AP Share (70%)	328000.1	295000.8	0000
Mini Hydro Schemes (Peddapalli 5 MW, Palair 2 MW and Chettipeta 1 MW)	13000.1	4000.88	0000
Nagarjunasagar Left Canal Power House (2 x 30 MW)	86000.7	30000.91	0000
Nagarjunasagar Right Canal Power House (3 x 30 MW)	171000.1	116000.21	0000
Nizamsagar Hydro Electric Scheme (2 x 5 MW)	24000.1	3000.02	0000
Nagarjunasagar Hydro Electric Scheme (1 x 110 + 7 x 100)	1106000.1	1213000.86	0000
Penna Ahobilam Hydro Electric Scheme (2 x 10 MW)	1000.9	4000	0000
Pochampad Hydro Electric Scheme (3 x 9 MW)	63000.9	2000.54	0000
Priyadarshini Hydro Electric Scheme	124000.3	239000.02	39000
Singur Hydro Electric Scheme (2 x 7.5 MW)	8000.4	5000.35	0000
Srisailam Left Bank Hydro Electric Scheme (6 x 150 MW)	1803000.7	1280000.38	0000
Srisailam Right Bank Hydro Electric Scheme (7 x 110 MW)	1811000.4	1277000.02	0000
Tungabhadra Hydro Electric Scheme (4 x 9 MW + 4 x 9 MW) AP Share (80%)	157000.5	152000.76	0000
Upper Sileru Hydro electric Scheme (4 x 60 MW)	621000.4	231000.59	0000
Total :	**7824000.2**	**5531000.42**	**39000**

[3] http://www.apgenco.gov.in/inner.asp?frm=Performance_thermal
[4] http://www.apgenco.gov.in/inner.asp?frm=Performance_hydel

Thus, hydro contributed only 5531000.42 MWh (**16.51%)** to the total power generated in the state of Andhra Pradesh during the year 2009-10 i.e. 33502000MWh[5]. This makes it clear that the grid to which the SLS Hydro project intends to supply renewable electricity continues to remain fossil fuel intensive. Thus, **P2** has been chosen as the baseline scenario.

P3 – The installation of a new fossil fuel based power plant is not a credible baseline as to undertake an investment on a similar scale is not feasible. Further, there are no coal linkages available to the PP in Andhra Pradesh nor is coal available at a competitive price. Also, excluding this baseline is conservative as coal would result in higher baseline emissions (due to its higher CO_2 intensity).

In examining this option it is necessary to consider fuels, materials and technology available at the project site. We can therefore rule out wind, biomass, tidal or solar as no projects of similar scale have been developed in the Dummagudem village. Furthermore there is not enough exploitable wind power resource on the project site to build a wind power plant with equivalent amount of power generation i.e. 24MW. Moreover, biomass power generation of the same annual power output would require huge amounts of biomass which is in shortage in the regions where the project is located & comes at a cost. Similarly, tidal or solar implementation would be impossible in the region.

From the above analysis the regional grid (*Alternative P2*) has been taken as the baseline and baseline emissions have been calculated as per the methodology – "*I f the project activity is the installation of a new grid-connected renewable power plant/unit, 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".

For the purpose of the project activity the relevant grid is defined by the power generating units serving the same grid as the project activity. In the case of India there are regional grids which facilitate the transfer of electricity between states and which are supplied by central sector power stations operating in the region. Andhra Pradesh is part of the Southern Region and we have therefore considered the Southern grid.

We have adopted the approach specified in the *"Tool to calculate the emission factor for an electricity system version 2"* to calculate the CO_2 emission coefficient of the Southern regional electricity grid. The weighted average of simple operating margin and build margin has been used for calculation of the baseline. The grid emission factor has been obtained from the *"Central Electricity Authority CO_2 Baseline Database version 5"* and is fixed ex-ante at 0.89tCO_2/MWh and is calculated as shown in table below:

Table 9: Calculation of Combined Margin Grid Emission Factor

Parameter	**tCO_2/MWh**
Simple Operating Margin	0.97
Build Margin	0.82

[5] http://www.apgenco.gov.in/inner.asp?frm=operationalperformance

Combined Margin	0.89

B.5. Demonstration of additionality

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The following section demonstrates that the project activity is not part of the baseline scenario by drawing on version 05.2 of *"Tool for the demonstration and assessment of additionality"*.

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

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

The demonstration of the baseline scenarios (in section B4) was incorporated as per the steps contained in the methodology ACM 0002 version 11,which prescribes credible baseline scenarios for the project activity. Amongst the applicable baseline scenarios, we have chosen P2 as explained in section B.4 above.

Thus, the alternative to the project activity is:

<u>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 generated under the project would be generated in existing and new grid-connected power plants in the electricity system</u>

Under this alternative, the increasing demand of electricity would be met by increasing the installed capacity through the possible expansion of existing fossil fuel based power plants as well as construction of new power plants, according to the current policies and regulations. This is a realistic and credible baseline scenario, as shown in section B.4 above.

Thus, scenario ***P2*** is selected as an alternative to the project activity.

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

In terms of the alternatives mentioned above, all conform to local and national policies and are therefore credible.

Step 2: Investment analysis

The investment analysis has been undertaken in compliance with EB51 Annex 58 -*"Guidance on the Assessment of Investment Analysis, Version 3".*

Sub-step 2a: Determine appropriate analysis method

Since the alternative to the project activity is supply of electricity from grid *Option III i.e. benchmark analysis* has been used to demonstrate additionality of the project, which is in conformity with guidance 16 of Annex 58, EB 51.

Sub-step 2b: Option III. Apply benchmark analysis

The Internal Rate of Return (IRR) is one of the known financial indicators used to demonstrate the additionality of the project. Among the four financial indicators recommended by the "Additionality Tool", IRR is one alternative. The tool permits us to select either the Project IRR (the viability of the project to service debt) or the Equity IRR (the final return on the initial equity investment) to demonstrate the additionality. Out of the two, we have chosen to analyze the additionality using project IRR and compare it to a relevant benchmark as explained below.

The commercial lending rate has been selected as the benchmark for determining the investment worthiness of the project. The Prime Lending Rate (PLR) as the time of the decision making (15th September 2008[6]) was in the range of 13.25% to 14%[7]. The project developer had taken into consideration the lower range of the PLR as the benchmark i.e.13.25%.

Sub-step 2c: Calculation and comparison of financial indicators (only applicable to Options II and III):

The project IRR calculations include all the revenues and costs associated with the project. The revenues include the sale of electricity from the power plant as per the rate agreed in the Power Purchase Agreement (PPA)[8]. The major costs to be incurred (post implementation) are the operation and maintenance (O & M) of the equipments used in the project activity.

The costs and revenues have been detailed below:

Table 10: Financial analysis of project activity

Costs (in INR Lakhs)		
Description	**Value**	**Source**
Civil costs	7158.00	DPR
Hydro-Mechanical	1290.00	DPR
Electro-Mechanical equipment cost	7206.00	DPR
Power Evacuation	715.00	DPR
Other costs	425.00	DPR
Project Capital cost	**16794.00**	
Assumed IDC	1641.43	DPR
Project cost with IDC	**18435.43**	
Debt Equity Ratio (%)	70:30	IREDA Loan documents
Loan amount	12904.80	IREDA Loan documents
Loan Period (including grace period & construction period) in years	12 (10 + 2)	IREDA Loan documents
Loan Interest Rate (%)	12.15	IREDA Loan documents
Interest on Working Capital (%)	12.15	IREDA Loan documents
Fixed Operating Costs		

[6] Refer SLS board resolution dated 15th September 2008
[7] http://rbidocs.rbi.org.in/rdocs/Wss/PDFs/87674.pdf
[8] This is as per the Power Purchase Agreement signed with Tata Power Ltd.

Annual O & M costs (INR Lakhs/MW)	12.77	DPR
O & M Escalation (%)	5.72	CERC Norms
Lifetime of the project activity (years)	25.00	DPR
Expected Power Generation and Revenues		
Installed Capacity (kW)	24000	DPR
Operating Period (days)	365	DPR
Operating Hours	8760	-
Plant Load Factor (%)	49.18	DPR/IREDA Loan documents
Gross Power Generated (MWh)	103,400	DPR
Auxiliary Power consumption & Transmission Loss (%)	3.00	DPR
Net Power Export to grid (MWh)	100,300	DPR
Electricity sale rate (Rs/kWh)	3.50	Power Purchase Agreement (PPA)with Tata Power Trading Company Ltd
Duration of PPA	Up to 2012	Power Purchase Agreement (PPA)with Tata Power Trading Company Ltd
Escalation in sale rate (INR) until 2012	0	Power Purchase Agreement (PPA)with Tata Power Trading Company Ltd
Subsidy from Govt. And other Official Assistance (INR Lakhs)	580.00	MNRE Subsidy
Other Assumptions		
Depreciation Rate (Company's Act) E&M (%)	2.57	CERC Norms
Depreciation Rate Income Tax Act (%)	15.00	Income Tax Act of India
Minimum Alternate Tax (%)	11.33	Income Tax Act of India
RESULTS		
Project IRR without CDM Benefits (%)	**12.76**	**Calculated**

All the assumptions and costs have been taken from the Detailed Project Report (DPR)/IREDA Loan documents for the project activity. The DPR was prepared on 20th August 2008 and submitted to NEDCAP (Non Conventional Energy Development Corporation of Andhra Pradesh Ltd) on 22nd September 2008. The DPR was also submitted to IREDA (Indian Renewable Energy Development Agency Ltd) on 7th September 2009 and IREDA approved the loan.

It would appear that the project cost at Rs 7.68 Crores/MW appears to be on the higher side. However, the higher cost is on account of:

- This project is a very low head and high discharge project. The rated head is 4.8m and the discharge cumecs is very high. Hence the size of the turbine is very big (the runner diameter is 4.2 m).

- The Turbine Generator consists of the following major assemblies:
  - Stayring assembly
  - Distributor assembly
  - Discharge ring assembly
  - Draft tube assembly
  - Runner assembly
  - Oil tube assembly
  - Gear box
  - Gear box Lube oil system
  - Generator
  - Generator Lube oil system
  - Cooling water system
  - Drainage & Dewatering system
  - Compressed air system

- The increase in size of the runner diameter results in increase in size of Stayring assembly, thus the total weight which results in increase in cost.

- The Distributor assembly consists of accurately machined components, profiled components, bronze bush bearings, hydraulic servomotor. The increase in runner diameter results in increase in size of the fabricated, machined and outsourced components resulting in increasing the fabrication cost, machining cost and outsourced components cost which includes bronze components, thus increasing the overall cost of the assembly.

- The Runner assembly consists of accurately machined components, Stainless steel profiled components, bronze bush bearings, High strength components, etc. The increase in runner diameter increased the weight of these components which results in increase in cost.
- Gear box is an expensive part of the turbine. The increase in size of the runner diameter increases the size of the runner assembly and associated components connected to gearbox. This increases the capacity of the gearbox resulting in increase of gear box cost.

- The increase in capacity of Generator, Gearbox and size of turbine increase the capacity of auxiliary systems namely cooling water system, Drainage and Dewatering system and Compressed air system, due to which their cost increases.

- The increase in size and capacity of the above Turbine components and Generator increases the weight to be handled by the EOT crane, thus increasing its rating. Increase in rating of crane results in higher cost of crane.

- In this project due to the being head very low, pit type turbine had to be chosen. In this type of turbine, due to the lower setting, the excavation had to done to very low level, thus increasing the excavation cost. Further, in the pit turbines, civil works is very massive as from intake up to the pit, the construction is concrete structure and the turbine metal casing starts beyond the pit.

Hence the cost of civil works is very high, adding to the overall project cost.

The PLF has been estimated based on a detailed hydrological study by Tata Consulting Engineers (TCE), one of India's leading engineering consulting organisations. TCE is ISO 9001 - 2008 certified by Lloyd's Register Quality Assurance. The PLF has been estimated at 49.18%. This is in contrast to the PLF of 35% estimated by APERC in its tariff order for renewable energy plants (dated 20-03-2004). Since the PLF is estimated by a 3rd party engineering firm retained by the company, it confirms to the requirements of Annex 11 of EB 48.

The financial indicator has been computed for a period of 25 yrs, which is the operating life of the project. The technical life of the project has been estimated by Zhejiang Jinlun Electromechanic Co Ltd, the manufacturers of the turbine and hence, it confirms to Annex 15 of EB 50. The financial indicator calculation takes into consideration salvage value at the end of the terminal year, which conforms to Guidance 4 of Annex 58, EB 51. The tariff is based on the PPA with Tata Power Trading Company Ltd (TPTCL). The tariff of Rs 3.50/unit is valid until December 2012 and is subject to revision by mutual consent for the later period. The tariff offered is already 35% higher than that offered by APERC (Andhra Pradesh Electricity Regulatory Commission)[9]. Though it is true that the PPA contains a sentence to the effect that all efforts would be made by TPTCL to secure the highest possible rate, a careful reading of the entire sentence would reveal that it is suffixed with “based on market mechanism”. Further, the PPA also contains a sentence which states “In the event of APTCL[10] (Andhra Pradesh Trading Company Limited) not allowing corridor for inter-state sale & instead there being a need to sell power to APTCL itself, then the rate of sale of power would be based on the offer rate of APTCL which could be different from the rate offered above and the same should be acceptable to SLSPCL”. Considering the fact that the tariff fixed by APERC for hydel projects is much lower and that the generating capacity of Andhra Pradesh is envisaged to go multi forth in the times to come, the tariff is unlikely to move northwards. It is against this background that we have considered the tariff as fixed for the operating life of the project which in our opinion is quite conservative as compared to the tariff fixed by the APERC.

The project IRR, without taking into account CER revenues works out to be 12.76%**.** As evident, the project activity is financially unattractive as the project IRR (12.76 %) is found to be significantly lower than the benchmark (13.25%).

Sub-step 2d: Sensitivity analysis

The sensitivity analysis has been done in accordance with EB 51, Annex 58 ‘*Guidance on the Assessment of Investment Analysis’* paragraph 17 and 18. The guidance states that “*Only variables, including the initial investment cost, that constitute more than 20% of either total project costs or total project*

[9] The rate offered by APTCL is Rs 2.60/unit (which reduces by Rs.0.08/unit every year till the 10th year). Check www.**aperc**.gov.in/Other**Orders**/**Order**_RP_84_2003.doc

[10] APTCL comes under the umbrella of APERC.

revenues should be subjected to reasonable variation (all parameters varied need not necessarily be subjected to both negative and positive variations of the same magnitude), and the results of this variation should be presented in the PDD and be reproducible in the associated spreadsheets.. Where a DOE considers that a variable which constitute less than 20% have a material impact on the analysis they shall raise a corrective action request to include this variable in the sensitivity analysis". The IRR of the proposed project activity is driven by the electricity tariff and the investment costs. The IRR is also sensitive to variations in the electricity tariff and the O & M costs. Thus, we varied the project cost, Plant Load Factor (PLF), electricity tariff rate and the O& M cost in order to analyze the sensitivity of the project.

As per Guidance 18 of Annex 58, EB51 variations in the sensitivity analysis should at least cover a range of + 10% and -10%, unless this is not deemed appropriate in the context of the specific project circumstances. In this case, the project is already experiencing a cost overrun[11] and the PLF assumed is much higher than the APERC recommended PLF. Therefore, the probability of the project cost reducing or PLF increasing by as much as 10% is absolutely impossible. It was against this background that we had given 5% variation. Nevertheless, since the guidance requires that the sensitivity analysis should cover a range of +/-10%, we have provided the 10% variations also.. The results are shown below:

Table 11: Sensitivity Analysis

Factor	**Variation in project IRR**				
	-10%	**-5%**	**0%**	**+5%**	**+10%**
Project cost	14.39%	13.54%	**12.76%**	12.05%	11.40%
Plant Load Factor	10.92%	11.85%	**12.76%**	13.65%	14.52%
Electricity Tariff	11.13%	11.96%	**12.76%**	13.54%	14.29%
O&M Cost	13.00%	12.88%	**12.76%**	12.65%	12.53%
Benchmark (PLR)	*13.25%*				

The reasons relating to high project cost (Rs 7.68 Crores/MW) have already been highlighted in the section above. As mentioned, the project activity is already facing a cost overrun. Thus, it is highly unlikely that the project cost would reduce by even 5%.. Thus, it is clear that the project cost would never reduce and the project IRR would never cross the benchmark in this case.

The dependence of a hydro project on Plant Load Factor (PLF) poses a significant risk to the financial viability of the project activity. The sensitivity of the IRR to variations in PLF demonstrates the risk associated with the project. A 5% reduction in PLF (*estimated as 49.18% in the DPR*) lowers the project IRR to a paltry 11.85% whilst a 5% increase brings the project IRR (13.65%) above the benchmark, but is extremely unlikely considering the fact that PLF determination is a scientific process (undertaken by TCE, a renowned firm) based on hydrology studies and discharge data available at the site for 10 years. Further, there is always a chance that the PLF will be lower than historical estimates due to climatic conditions, leading to reduced rainfall and droughts. This is also highlighted by the fact that the Andhra Pradesh Electricity Regulatory Commission (APERC) in its tariff order for renewable energy plants dated 20-03-2004 considered 35% PLF as appropriate for mini hydel projects (< 25 MW). The project also received a GSP comment highlighting the fact that the assumed PLF seemed too high and would never be achieved. Thus, it is clear that a 5% increase in PLF is highly unlikely to occur. Thus, the

[11] Evidence for the same has now been provided to the DOE.

possibility of project IRR crossing the benchmark due to an increase in PLF is highly improbable. Furthermore any increase in the PLF than the sensitivity would be subjected to Annex 66, 67 of EB48.

The IRR is also sensitive to the electricity tariff and this parameter is important in determining the primary revenues of the project activity. The PPA signed with Tata Power Ltd offers a tariff of Rs 3.50/unit valid until Dec 2012 and is subject to revision by mutual consent for the later period. Though it is true that the PPA contains a sentence to the effect that all efforts would be made by TPTCL to secure the highest possible rate, a careful reading of the entire sentence would reveal that it is suffixed with "based on market mechanism". Further, the PPA also contains a sentence which states "In the event of APTCL not allowing corridor for inter-state sale & instead there being a need to sell power to APTCL itself, then the rate of sale of power would be based on the offer rate of APTCL which could be different from the rate offered above and the same should be acceptable to SLSPCL". This clearly highlights the risk that SLSPCL faces in terms of the availability of a higher tariff from TPTCL. If SLS is forced to sell power to the APTCL at Rs 2.60/unit, the financial viability of the project activity is gravely affected. Considering the fact that the tariff fixed by APERC for hydel projects is much lower and that the generating capacity of Andhra Pradesh is envisaged to go multi forth in the times to come, the tariff is unlikely to move northwards. It is against this background that we have considered the tariff as fixed for the operating life of the project which in our opinion is quite conservative as compared to the tariff fixed by the APERC There is unlikely to be an escalation of tariff in the future and the above table clearly shows the limited impact of adjusting the power tariff on the IRR.

Lastly, a variation in the O & M costs has been considered in order to complete the sensitivity analysis. As input costs are going up every year due to inflation, the cost of O&M coming down is not a realistic scenario at all. However, we have still considered a 5% reduction in these costs for the sake of completeness. This raises the project IRR to 12.88%, this is still way below the benchmark (13.25%). Thus, it is clear that the project IRR would not cross the benchmark even if O & M costs were to marginally reduce in the future.

Thus, it is clear that the project IRR remains below the benchmark even after variations in the input parameters listed above. Thus, the sensitivity analysis undertaken above confirms the additionality of the project activity.

Step 3: Barrier analysis

Investment analysis has been undertaken.

Step 4: Common practice analysis

Common practice analysis acts as a credibility check to complement the investment analysis done in Step 2. According to the *"Tool for the demonstration and assessment of additionality version 05.2"* – "*Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc.*"

The common practice analysis is identified and discussed through the following sub-steps:

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

As per step 4 of the Additionality tool states that the projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Since the regulatory framework differs from state to state projects located in Andhra Pradesh have been taken consideration, which has considered as geographical region. There were in all 57 projects which were operational and 11 projects were under implementation /approval stage. at the time of web hosting of the PDD as per the list given below:

Table 12: Hydro Power plants installed in Andhra Pradesh

S No	Name of Project	Agency	Capacity (MW)			
			Units	Total	Date of Commissioning	CDM (Y/N)
	SHP projects upto 25 MW					
	Public Sector Projects					
1	Nizam Sagar	APGENCO	2x5	10.00	1955-56	N
2	Donkarayi	APGENCO	1x25	25.00	1982-83	N
3	Kakatiya D-83 M10-6-550	APGENCO	2x0.325	0.65	1986-87	N
4	Kakatiya D-83 M19-0-566/2-230	APGENCO	3x0.23	0.69	12.4.87	N
5	Chettipeta	APGENCO	2x0.5	1.00	1.10.91	N
6	Palair M87	APGENCO	2x1000	2.00	13-2-1993	N
7	Penna Ahobilm	APGENCO	2x10	20.00	23.1.94	N
8	Kakatiya D-83 M9-7-385	APGENCO	2x0.5	1.00	18.1.1994	N
9	Kakatiya D-83 M14-7-500	APGENCO	2x0.5	1.00	6.12.1995	N
10	Kakatiya D-83 M18-5-550	APGENCO	3x0.22	0.66	14.1.98/12.3.98	N
11	Singur	APGENCO	2x7.5	15.00	2000-01	N
12	Kakatiya D-83 M16-5-550	APGENCO	2x0.5	1.00	8.1.2001	N
13	Kakatiya D-83 6th Mile	APGENCO	2x0.5	1.00	2003-04	N
14	Kakatiya D-83 7th Mile	APGENCO	2x0.5	1.00	2003-04	N
15	Kakatiya D-83 12th Mile	APGENCO	2x325	0.65	2003-04	N
16	Kakatiya D-83 18th Mile	APGENCO	2x0.75	1.50	2003-04	N
17	Kakatiya D-83 19th Mile	APGENCO	2x0.75	1.50	2003-04	N

	Private Sector Projects					
18	Guntur BC M0	Deccen		3.75	28/02/1996	N
19	Adanki BC M 6	Dhanlkshmi		2.61	23-07-1997	N
20	Adanki BC M 4 & 6	Dhanlakshmi		2.00	24-11-1997	N
21	Guntur BC III	Sagar		4.30	27-11-1997	N
22	Adanki BC M 4	Dhanalkshmi		1.59	23-12-1997	N
23	Guntur BC M5/4, 5/5 5/2 550	KCP		1.50	14-03-1998	N
24	KC Canal	Sagar		4.00	09-07-1998	N
25	Guntur BC M5/4	KCP		1.50	18-09-1998	N
26	Guntur BC M 5/5-550	KCP		1.50	20.11.1998	N
27	Guntur BC M 13 & 14	Rayalaseema		3.00	21-11-1998	N
28	Ongole BC M 2/3/199 2/6/190	SKJ Power		1.50	27-01-1999	N
29	Guntur BC M 5/2-550	KCP		1.50	04-02-1999	N
30	Adanki BC M 10	Trident		2.00	26-08-1999	N
31	Guntur BC M5/4-550	KCP		2.25	09-06-1999	N
32	Adanki BC M 13	Trident		2.00	13-10-1999	N
33	Adanki BC M 28	Trident		3.00	28-02-2001	N
34	Bellamkond BC M-5-2-250 Sc.II	Bhavani		0.55	28-08-1999	N
35	Budameru	Active Power		1.40	28-04-2000	N
36	Guntur BC M20, 21& 22 Sc.I	Thirumala		0.80	07-01-2000	N
37	Guntur BC M20, 21& 22 Sc.II	Thirumala		0.80	02-02-2000	N
38	Guntur BC M20, 21& 22 Sc.III	Thirumala		0.80	11-06-2000	N
39	Bellamkonda BC M0	Espar		1.30	04-08-2000	N
40	Bellamkonda BC M 0/1	Shivani		0.75	03-11-2000	N

41	Adanki BC M 17&18 Sch.I &II	Jayalakshmi		4.00	27-02-2000	N
42	Srisailam RC Sch.I,II,& III	NCL		7.50	28-09-2000	N
43	Yeleru Reservoir	Manihamsa		3.00	17-01-2000	N
44	Mudimanikyam Major NSLC	Srinivasa		0.55	15-04-2001	N
45	Chilkapur Major Block-10 Sc.I	Akshay		0.50	13-07-2000	N
46	Chilkapur Major Block-10 Sc.II	Akshay		0.50	09-11-2000	N
47	Pedandipadu BC	PMC		0.65	17-05-2001	N
48	Janapadu BC	Janapadu		1.00	19-09-2001	N
49	Vemuleru Vagu Reservoir	NATL		4.05	29-09-2001	N
50	Kakatiya Canal -Lower Manniar	Saraswati		2.00	10-02-2001	N
51	Nippula Vagu	K.M. Power		4.00	02-06-2002	Y (Registered)
52	Nandigama BC M5, M3 & M6 Sc.I &II	Kallam		2.40	29-01-2002	Y (Validation)
53	Nippula Vagu KM 10 to 14	K.M. Power	2x1650	3.30	11-07-2002	Y (Registered)
54	Nippula Vagu KM 14 to 18 Sc.I &II	K.M. Power		4.00	21-11-2003	Y (Registered)
55	Addanki BC	Trident		2.80	2003-04	**N**
56	Bellamkonda BC M3/1 to 3/7	Bhavani		0.55	17-11-2004	**N**
57	Somasila Resv.	Balaji		10.00	2005-06	Y (Rejected)
	Total			**178.85**		

Out of the 57 projects listed above, 17 projects have been promoted by Govt.of Andhra Pradesh and hence their "Access to Finance" and "Investment Climate" is different. Out of remaining 40 projects, 5 projects (including 1 rejection) had applied for CDM benefits. These projects need not be included in the analysis as per step 4 of additionality tool. That leaves 35 projects for common practice analysis. "A look at the list given above shows that the capacity of the projects ranges from 0.5 MW to 7.5 MW including those under construction/approval stage"
Therefore, there are no similar project activities in the region selected for the common practices analysis.

As can be seen from the above table/s, the proposed project activity is not a common occurrence at all and requires CDM funding in order to be implemented.

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

No similar power plants (in terms of scale and CDM registration) were found to be operating in the state.

DEMONSTRATION AND ASSESSMENT OF PRIOR CONSIDERATION OF THE CDM

As per Annex 46 of EB 41,

Proposed project activities with a start date before 2 August 2008, for which the start date is prior to the date of publication of the PDD for global stakeholder consultation, are required to demonstrate that the CDM was seriously considered in the decision to implement the project activity. Such demonstration requires the following elements to be satisfied:

(a) *The project participant must indicate awareness of the CDM prior to the project activity start date, and that the benefits of the CDM were a decisive factor in the decision to proceed with the project. Evidence to support this would include, inter alia, minutes and/or notes related to the consideration of the decision by the Board of Directors, or equivalent, of the project participant, to undertake the project as a CDM project activity.*

The investment decision for the project activity was made on 15th September 2008. The start date of the project activity is 5th October 2009, which is after 2nd August 2008. The PP has submitted its 'Prior consideration of CDM' form to the UNFCCC on 17th November 2009 and the UNFCCC Secretariat acknowledged receipt on 17th December 2009. Evidence for the same will be provided to the DOE. Thus, point (a) is not applicable to the project activity.

(b) *The project participant must indicate, by means of reliable evidence, that continuing and real actions were taken to secure CDM status for the project in parallel with its implementation .Evidence to support this should include, inter alia, contracts with consultants for CDM/PDD/methodology services, Emission Reduction Purchase Agreements or other documentation related to the sale of the potential CERs (including correspondence with multilateral financial institutions or carbon funds), evidence of agreements or negotiations with a DOE for validation services, submission of a new methodology to the CDM Executive Board, publication in newspaper, interviews with DNA, earlier correspondence on the project with the DNA or the UNFCCC secretariat;*

As the PP has already submitted 'Prior Consideration of CDM' to the UNFCCC as mentioned above, point (b) is not applicable.

B.6. Emission reductions
B.6.1. Explanation of methodological choices

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Baseline Emissions

The baseline emissions are calculated as per page 8 of the methodology – "*Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity, calculated as follows:*

$$BE_y = EG_{PJ,y} * EF_{grid,CM,y}$$ Equation 1

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)

As mentioned in the methodology, $EG_{PJ,y}$ is calculated as follows for greenfield renewable energy power plants:

$$EG_{PJ,y} = EG_{facility,y}$$ Equation 2

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)

The electricity supplied by the project activity is calculated from the following equation:

$$EG_{facility,y} = EG_{gross} - EG_{aux}$$ Equation 3

Where:

EG_{gross}	Gross electricity generation by the project activity in year y (MWh)
EG_{aux}	Auxiliary consumption by the project activity in year y (MWh)

Since the carbon dioxide emission factor has been fixed ex-ante at 0.89 tCO_2/MWh, equation 1 reduces to:

$$BE_y = EG_{PJ,y} * 0.89$$ Equation 4

Project Emissions

$$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y}$$

Where:

PE_y	= Project emissions in year *y* (tCO_2e/yr)
$PE_{FF,y}$	= Project emissions from fossil fuel consumption in year *y* (tCO_2/yr)
$PE_{GP,y}$	= Project emissions from the operation of geothermal power plants due to the release of

non-condensable gases in year y (tCO_2e/yr)

$PE_{HP,y}$ = Project emissions from water reservoirs of hydro power plants in year y (tCO_2e/yr)

The procedure to calculate the project emissions from each of these sources is presented next.

Project Emissions from fossil Fuel Combustion ($PE_{FF,y}$)

For geothermal and solar thermal projects, which also use fossil fuels for electricity generation, CO_2 emissions from the combustion of fossil fuels shall be accounted for as project emissions ($PE_{FF,y}$). It is expected that the backup DG set present at the site may use some diesel in order to operate and thus we have accounted the emissions due to the same.

$PE_{FF,y}$ is calculated as per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", Version 2:

$PE_{FC,y} = \sum FC_y \text{ X } COEF_y$

Where:

$PE_{FC,y}$ = CO_2 emissions from diesel combustion in process, during the year y (tCO_2/yr)
FC_y = Quantity of diesel combusted in the process, in year y (mass/yr)
$COEF_y$ = CO_2 emission coefficient of diesel, in year y (tCO_2/mass)

Option B of the tool is chosen to calculate the CO_2 emission coefficient $COEF_y$ based on net calorific value and CO_2 emission factor of the fuel type, as follows:

$COEF_y = NCV_y * EF_{CO2,y}$

Where

NCV_y = Weighted Average net calorific value of diesel in year y (GJ/mass or volume unit)
$EF_{CO2,y}$ = Weighted Average CO_2 emission factor of diesel (tCO_2/GJ)

Project Emissions from Geothermal Plants ($PE_{GP,y}$)

As the project activity is not a geothermal plant, $PE_{GP,y} = 0$

Project Emissions from Hydro power plants ($PE_{HP,y}$)

The project activity is a run of river hydro project & does not result in a new reservoir. Thus, as per page 6 of the methodology –

$$PE_{HP,y} = 0$$

Thus,

$\mathbf{PE_y = PE_{FF,y}}$

Leakage

As per page 11 of the methodology – *"Project participants do not need to consider these emission sources as leakage in applying this methodology.*"

The leakage has therefore been neglected in line with the guidance.

Emission Reductions

As per page 11 of the methodology - *Emission reductions are calculated as follows:*

$$ER_y = BE_y - PE_y \qquad \text{Equation 8}$$

Where:

ER_y	*Emission reductions in year y (t CO_2e/yr)*
BE_y	*Baseline emissions in year y (t CO_2e/yr.*
PE_y	*Project emissions in year y (t CO_2/yr)*

B.6.2. Data and parameters fixed ex ante

(Copy this table for each piece of data and parameter.)

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
Source of data	Central Electricity Authority ,India
Value(s) applied	0.890
Choice of data or Measurement methods and procedures	Central Electricity Authority CO_2 Baseline Database version 5 Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
Purpose of data	Calculation of Baseline emissions
Additional comment	This value is fixed Ex-ante

B.6.3. Ex ante calculation of emission reductions

>>

Baseline Emissions

As mentioned in section.B.6.1, $EG_{PJ,y}$ is calculated as follows for greenfield renewable energy power plants:

$$EG_{PJ,y} = EG_{facility,y} \qquad \text{Equation 2}$$

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)

The electricity supplied by the project activity is calculated from the following equation:

$$EG_{facility,y} = EG_{gross} - EG_{aux}$$ Equation 3

Where:
EG_{gross} Gross electricity generation by the project activity in year y (MWh)
EG_{aux} Auxiliary consumption by the project activity in year y (MWh)

As per the calculations made in the DPR, the 24 MW hydro power plant operates 365 days a year at a plant load factor of 49.18 % generating *103,400 MWh* of power. The auxiliaries of the power plant are expected to consume *1,551MWh* of power @ 1.5% of the gross generation. Further, transmission losses have been assumed @ 1.5% of total generation, leading to a further reduction of *1,551MWh* of exported power.

Thus, EG_{gross} = 103,400 MWh

And,

EG_{aux} = 1,551 + 1,551 MWh
= 3,102 MWh

$$EG_{facility,y} = EG_{gross} - EG_{aux}$$
= 100,300 MWh

The gross energy generation & auxiliary consumption of the project activity will be monitored in order to meet the methodology requirement.

Since the carbon dioxide emission factor has been fixed ex-ante at 0.89 tCO_2/MWh, equation 1 reduces to:

$$BE_y = EG_{PJ,y} * 0.89$$ Equation 4

Thus,

BE_y = 89,267 t CO_2e/yr

Project Emissions

As discussed above,

$PE_y = PE_{FF,y} + PE_{HP,y}$

$PE_{FC,y} = \sum FC_y \text{ X } COEF_y$

Where:
$PE_{FC,y}$ = CO_2 emissions from diesel combustion in process, during the year y (tCO_2/yr)
FC_y = Quantity of diesel combusted in the process, in year y (mass/yr)
$COEF_y$ = CO_2 emission coefficient of diesel, in year y (tCO_2/mass)

Option B of the tool is chosen to calculate the CO_2 emission coefficient $COEF_y$ based on net calorific value and CO_2 emission factor of the fuel type, as follows:

$COEF_y = NCV_y * EF_{CO2,y}$

Where
NCV_y = Average net calorific value of diesel in year *y* (GJ/mass or volume unit)
$EF_{CO2,y}$ = CO_2 emission factor of diesel (tCO_2/GJ)

The NCV of diesel is obtained from Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories and is estimated at 43.0 TJ/Gg which is equivalent to . The CO_2 emission factor of diesel is obtained from e 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories and is estimated as 74100 kg/TJ which is equivalent to 74.1 T/TJ.

Thus,

$COEF_y = (43.0 * 74.1)/1000$

$= 3.186\ tCO_2$/tonne

&

$PE_{FC,y} = \sum FC_y \text{ X } COEF_y$

$PE_{FC,y} = FC_y \text{ X } 3.186$

It is intitally assumed that no diesel will be used in the DG set & therefore,

$\mathbf{PE_{FC,y} = 0}$

The quantity of diesel used, its NCV and its CO_2 emission factor will be monitored post project implementation as per the guidance provided in the *"Tool to calculate project or leakage CO2 emissions from fossil fuel combustion."*

Thus,
$\mathbf{PE_y = PE_{FF,y}}$
$= 0$

$\mathbf{PE_y \quad = 0\ tCO2e}$

Leakage

As per page 11 of the methodology – *"Project participants do not need to consider these emission sources as leakage in applying this methodology.*"

The leakage has therefore been neglected in line with the guidance.

Emission Reductions

As per page 11 of the methodology - *Emission reductions are calculated as follows:*

$$ER_y = BE_y - PE_y \qquad \text{Equation 8}$$

Where:

ER_y	*Emission reductions in year y (t CO_2e/yr)*
BE_y	*Baseline emissions in year y (t CO_2e/yr)*
PE_y	*Project emissions in year y (t CO_2/yr)*

Thus,

$$ER_y = BE_y - PE_y$$

= 89,267 – 0

ER_y = 89,267 t CO_2e/yr

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)
2013 (~~August~~ 10 October 2013 – 31 December 2013)	0	37,195	0	37,195
~~2012~~2014	0	89,267	0	89,267
2015~~3~~	0	89,267	0	89,267
2016~~4~~	0	89,267	0	89,267
2017~~5~~	0	89,267	0	89,267
2018~~6~~	0	89,267	0	89,267
2019~~7~~	0	89,267	0	89,267
2020~~18~~	0	89,267	0	89,267
2021~~19~~	0	89,267	0	89,267
2020	0	89,267	0	89,267
2022~~1~~(January-~~July~~09 October 2022)	0	52,072	0	52,072
Total	0	892,670	0	892,670
Total number of crediting years	10			
Annual average over the crediting period	0	89,267	0	89,267

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

(Copy this table for each piece of data and parameter.)

Data / Parameter	**$EG_{facility,y}$**
Unit	MWh
Description	Quantity of net electricity generation supplied by the project plant/unit to the grid
Source of data	Electricity meter readings from plant records
Value(s) applied	100,300
Measurement methods and procedures	The quantity of net electricity supplied will be based on the Joint Meter Readings (JMR) undertaken by SLS Power Corporation Ltd & representatives from the local grid/Tata Power on a monthly basis (based on the provisions provided in the PPA). The quantity supplied to the grid can be cross checked by measuring gross electricity generation (at the turbines) and auxiliary consumption, if any at the site. A logbook will be maintained on site to record hourly readings from the turbine energy meter/s and any auxiliaries also. The readings will be taken by the shift supervisor. This hourly data will be signed off at the end of every 8 hour shift by the engineer in charge of the shift and again at the end of each day by the power plant manager.
Monitoring frequency	Hourly Monitoring and Monthly Recording
QA/QC procedures	The generation energy meter /s will be calibrated annually as per CDM guidelines. The net electricity supplied to the grid can be cross checked against invoices raised by the PP to the grid/Tata Power.
Purpose of data	Calculation of Emission Reductions
Additional comment	All data will be kept for a minimum of 2 years following issuance of certified emission reductions or the end of the crediting period, whichever is later.

Data / Parameter	EG_{gross}
Unit	MWh
Description	Total electricity produced by the project activity, including the electricity supplied to the grid and the electricity supplied to internal loads, in year y
Source of data	Detailed Project Report
Value(s) applied	103,400
Measurement methods and procedures	The gross energy generation will be monitored on an hourly basis (in each shift) based on the readings obtained from the energy meters present on the turbines. The electricity supplied to internal loads will also be monitored on a shift wise basis (hourly in each shift) using energy meters and logbooks will be maintained for the same.
Monitoring frequency	Hourly and recorded monthly
QA/QC procedures	The gross generation values can be back calculated by adding together the quantity of electricity fed to the grid & that used within the power plant (for internal loads). This can also be cross checked against the log book readings for the same. The generation energy meter /s will be calibrated annually as per CDM guidelines
Purpose of data	Calculation of Emission Reductions
Additional comment	All data will be kept for a minimum of 2 years following issuance of certified emission reductions or the end of the crediting period, whichever is later

Data / Parameter	EG_{aux}
Unit	MWh
Description	Total auxiliary electricity used for internal loads in the year y
Source of data	Detailed Project Report
Value(s) applied	3,102
Measurement methods and procedures	The auxiliary energy consumption will be monitored on an hourly basis (in each shift) based on the readings obtained from the energy meters present on the various internal loads. A logbook will be maintained for the same.
Monitoring frequency	Hourly and Monthly Recorded
QA/QC procedures	The Auxiliary consumption values can be cross checked against the log book readings. The energy meter /s will be calibrated annually as per CDM guidelines.
Purpose of data	Calculation of Emission Reductions
Additional comment	All data will be kept for a minimum of 2 years following issuance of certified emission reductions or the end of the crediting period, whichever is later

Data / Parameter	**FC_y**
Unit	Tonnes/yr
Description	Quantity of diesel combusted in the process, in year y
Source of data	Factory records
Value(s) applied	0
Measurement methods and procedures	The quantity of diesel used in the backup DG present on the site will be measured continuously using mass or volume meters (ruler gauge in daily tank). This will then be noted in the logbooks present at the site and summarized into daily reports.
Monitoring frequency	Daily
QA/QC procedures	The consistency of metered fuel consumption quantities will be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities will also be cross-checked with available purchase invoices from the financial records.
Purpose of data	Information Purpose
Additional comment	All data will be kept for a minimum of 2 years following issuance of certified emission reductions or the end of the crediting period, whichever is later.

Data / Parameter	**NCV_y**
Unit	GJ/Gg
Description	Average net calorific value of diesel in year *y*
Source of data	Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	0.043
Measurement methods and procedures	The NCV of the fossil fuel used should be calculated using either one of the following options: a) Preferably be obtained from values provided by the fuel supplier in invoices. In case this data is not available, b) Measurements by the project participants themselves or c) Regional or national default values or d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories. For a) and b) above, measurements should be undertaken in line with national or international fuel standards.
Monitoring frequency	Annual
QA/QC procedures	The PP will verify that the values under a), b) and c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range the PP will collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories selected in a), b) or c) will have ISO17025 accreditation or will justify that they can comply with similar quality standards.
Purpose of data	
Additional comment	Applicable where Option B is used.

Data / Parameter	$EF_{CO2,y}$
Unit	tCO_2/GJ
Description	CO_2 emission factor of diesel
Source of data	Table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	74.1
Measurement methods and procedures	The CO_2 emission factor of the fossil fuel used should be calculated using either one of the following options: a) The preferred source is values provided by the fuel supplier in invoices b)Measurements by the project participants c) Regional or national default values d) IPCC default values at the upper 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 For a) and b) above, measurements should be undertaken in line with national or international fuel standards.
Monitoring frequency	-
QA/QC procedures	-
Purpose of data	Information Purpose
Additional comment	Applicable where option B is used. For a): If the fuel supplier does provide the NCV value and the CO_2 emission factor on the invoice and these two values are based on measurements for this specific fuel, this CO_2 factor should be used. If another source for the CO_2 emission factor is used or no CO_2 emission factor is provided, Options b), c) or d) should be used.

B.7.2. Sampling plan

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There is no sampling plan involved in the project activity.

B.7.3. Other elements of monitoring plan

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In accordance with the methodology all the data collected during the crediting period will be archived electronically and kept for at least two years after the end of crediting period. 100% of the data will be monitored and the meters owned by grid/project owners will be calibrated at regular intervals to ensure low uncertainty in the monitored data.

Monitoring shall consist of metering the net electricity supplied to the grid ($EG_{facility,y}$), turbine gross generation (EG_{gross})and any auxiliary consumption (EG_{aux}) of electricity due to the internal loads present in the project activity. An internal audit will be carried out every year at the power plant to ensure that these parameters are being monitored in accordance with the project PDD.

The certified emission reductions (CERs) will be determined annually based on the monthly JMRs undertaken by representatives of SLS Power Corporation Ltd & the grid. The PP will then raise monthly electricity sales invoices to the grid/Tata Power (the end user of the generated energy) based on these JMRs. The same figure will be reported to Ecolutions in order to estimate the monthly emission reductions.

In order to cross check the accuracy of this figure, the PP will also monitor Total/gross electricity generation from the turbine/s and any auxiliary consumption due to the internal loads. There will be three 8 hour shifts and the readings from energy meter/s will be taken on an hourly basis by the shift supervisor and recorded in logbooks. This hourly data will be signed off at the end of every shift by the engineer in charge of the shift and again at the end of each day by the power plant manager. The power plant manager will analyze the data every month and report to the head office. The data will be archived electronically every month and invoices of electricity sales will be maintained.

In line with the monitoring requirements of the methodology and the tools referred to in the methodology, the PP will also monitor the following parameters in order to estimate project emissions:

- The quantity of fossil fuel/diesel (FC_y) used in the backup DG present at the site, which will be determined using ruler gauges in the diesel tank available for the DG set
- The Net Calorific Value (NCV_y) of the fossil fuel/diesel used in the project activity, which will be determined using either supplier's receipts or IPCC default data
- The CO_2 emission factor of the fossil fuel/diesel used in the project activity ($E_{FCO2,y}$), which will be determined using either supplier's receipts or IPCC default data

The suppliers of the equipments will train the staff in- charge during erection, to operate and maintain the equipments efficiently. Apart from this, the equipment supplier will provide complete manuals and documentation providing details for the maintenance schedule and the required activities associated with the project. All the meters used in the project activity will be calibrated on an annual basis.

The monitored data will be reported by the PP to Ecolutions (the CDM consultant) on a monthly basis for the calculation and estimation of emission reductions. This data will be checked against initial estimates and a summary report will be provided quarterly by Ecolutions. If the project is not performing as expected or if there are any negative impacts on the volume of emission reductions obtained, on the basis of the monthly data being monitored, a report will be sent to the PP outlining where the project is deviating in its generation of emission reductions and the immediate measures which need to be undertaken to maintain the expected generation of emission reductions from the operation of this project.

SECTION C. Duration and crediting period

C.1. Duration of project activity

C.1.1. Start date of project activity

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05/10/2009 – this was the date on which an order for civil works was placed by SLS Power Corporation Ltd to Sri Lakshmi Constructions Ltd.

C.1.2. Expected operational lifetime of project activity

>>

25y-00m

C.2. Crediting period of project activity

C.2.1. Type of crediting period

>>

Fixed 10 Years Crediting Period

C.2.2. Start date of crediting period

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10/10/2013 ~~01/08/2011 or the date of registration with the CDM Board, whichever is later~~

C.2.3. Length of crediting period
10 Years

SECTION D. Environmental impacts
D.1. Analysis of environmental impacts
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The project is a run-of-river type hydro power project, therefore environmental impacts typically associated with hydro power plants such as construction of dams, inundation of large areas and change in waterways do not occur. All the guidelines provided by the Ministry of Environment and Forests will be followed during the construction and operation of the project

D.2. Environmental impact assessment
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The environmental impacts are not considered significant as it is the run-of-the river project and as per Government mandate no EIA is required. After the completion of the construction of the project, the project will be put into operation only after inspection and acceptance of Andhra Pradesh State Pollution Control Board (AP SPCB), obtained through a 'Consent to Establish/Operate'.

SECTION E. Local stakeholder consultation
E.1. Solicitation of comments from local stakeholders
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The CDM stakeholder's consultation was undertaken on 28th December 2009 at the site of the hydro project. A notice was placed in the local Telugu newspaper, the Andhra Jyothi on 22nd December 2009 and comments were invited. A total of 30 people attended the meeting. The representatives of SLS Power Corporation Ltd and Ecolutions were also present, in order to discuss the CDM benefits accrued from this project[12].

The Andhra Pradesh State Pollution Control Board had also invited the people in the surrounding areas of the project activity for a public hearing on 25th December 2007 and asked them to raise their concerns and suggestions with respect to the project activity. The public hearing was conducted in the presence of officials from AP SPCB and the local Panchayat. The project owners explained to those present the purpose of the project activity and answered queries relating to the implementation of the project. The employment benefits accruing from the project were discussed, as well as its eligibility for carbon credits under the Kyoto Protocol.

The Government of Andhra Pradesh state had made it mandatory for all hydroelectric projects proposed in the region to undertake a public consultation before the start of the implementation of work. The project data must be made publicly available by the project owners in national and local dailies and invite comments for a period of 60 days. Based on the comments received during the public consultation period and the feedback from the project participants on how the public comments are addressed, the Government of Andhra Pradesh decides whether to sanction the project.

The project activity has also obtained a No Objection Certificate (NOC) from the Gram Panchayat of the local village on 26th October 2009.

The Non-Conventional Energy Development Corporation of Andhra Pradesh (NEDCAP), the policy implementation body in respect of renewable energy projects in Andhra Pradesh has also reviewed the project documentation and awarded clearance to the project on 30th September 2009. The project has

[12] Evidence for the meeting will be provided to the DOE during validation.

also obtained clearance from the Irrigation & CAD (PW: Reforms) Department for utilizing the water resources in the Andhra Pradesh state on 17^{th} August 2009.

A national stakeholder review was carried out through the Host Country approval from Ministry of Environment and Forests (MoEF), the Designated National Authority of India. The MoEF meeting was held on 31^{st} March 2010 and the Host Country Approval was issued on 18^{th} August 2010.

E.2. Summary of comments received

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No comments have been received.

E.3. Report on consideration of comments received

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Since no comments have been received, no report has been generated on consideration.

SECTION F. Approval and authorization

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The project activity has also obtained a No Objection Certificate (NOC) from the Gram Panchayat of the local village on 26^{th} October 2009.

The Non-Conventional Energy Development Corporation of Andhra Pradesh (NEDCAP), the policy implementation body in respect of renewable energy projects in Andhra Pradesh has also reviewed the project documentation and awarded clearance to the project on 30^{th} September 2009. The project has also obtained clearance from the Irrigation & CAD (PW: Reforms) Department for utilizing the water resources in the Andhra Pradesh state on 17^{th} August 2009.

A national stakeholder review was carried out through the Host Country approval from Ministry of Environment and Forests (MoEF), the Designated National Authority of India. The MoEF meeting was held on 31^{st} March 2010 and the Host Country Approval was issued on 18^{th} August 2010.

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Appendix 1: Contact information of project participants

Organization name	M/s SLS Power Corporation Limited
Street/P.O. Box	121/1 12th Cross, 2nd Stage, West Of Chord Road
Building	Mahalakshmi Puraram, (Near G D NAIDU HALL)
City	Bangalore
State/Region	Karnataka
Postcode	560086
Country	India
Telephone	+91-80 23195162/63
Fax	+91-80 23195164
E-mail	slspowercorporation@gmail.com
Website	-
Contact person	-
Title	Joint Managing Director
Salutation	Mr.
Last name	Reddy
Middle name	Chandra
First name	Jayachandra
Department	-
Mobile	-
Direct fax	-
Direct tel.	+91-80 23195162/63
Personal e-mail	slspowercorporation@gmail.com

Appendix 2: Affirmation regarding public funding

No public funding from annex 1countries is involved in the project activity

Appendix 3: Applicability of selected methodology

Detailed applicability condition for the selected methodology is provided in section B.2

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

Please refer to B.6

Appendix 5: Further background information on monitoring plan

Please refer to B.7

Appendix 6: Summary of post registration changes

The project could not be completed as envisaged due to the reasons provided below, hence the crediting period needs to be shifted by 2 years.

There was a severe flood in July/August 2010 in Godavari river at our project site in Dummagudem, Bhadrachalam in Andhra Pradesh with a discharge of 19 lakh cusecs inflicting heavy damages. We had preferred an insurance claim of Rs.12.33crores. The settlement of our claim took around 2 years. The settlement was also not made in full and we received Rs.7.79crores as against Rs.12.3crores (63%). The inordinate delay and short settlement resulted in a severe cash flow constraint and we could not meet our commitments to suppliers and contractors since the available funds were utilized for flood restoration works and thereby the project works were delayed. The restoration works like desilting and dewatering and reconstruction of the coffer dam also took a long periods for completion.

There was another flood in September 2011 which also accounted for the delay in commissioning. In respect of the 2nd flood we have still not received the settlement and it is under process.

There was floods again in 2012 which affected our project commissioning works

We also could not obtain all the Governmental sanctions in time due to the agitations on account of the Telangana issues. In view of the above reasons which were not in our control and which were due to force majeure conditions the project was delayed.

With reference to the above we enclose the following documents:

1. The flood occurrence report in respect of the 1st flood in July/August 2010 and also newspaper reports
2. In respect of 2nd flood in Sept 2011,we enclose the flood occurrence report and newspaper reports.

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Details of settlement in respect of the 1st flood:

SL No.	Date	Amount
1.	01.02.2012	3.1crores
2.	11.01.2013	4.69 crores

	Total	7.79
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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		