CLEAN DEVELOPMENT MECHANISM
SIMPLIFIED PROJECT DESIGN DOCUMENT
FOR SMALL SCALE PROJECT ACTIVITIES (SSC-PDD)
Version 01 (21 January, 2003)

CONTENTS

A. General Description of project activity

A.1 Title of the project activity:

Magal Ganga Small Hydropower Project

A.2 Description of the project activity:

This PDD presents the Magal Ganga Small-Hydropower Project, a proposed future investment in a small-scale, run-of-river hydropower plant in Sri Lanka. The Magal Ganga small-hydropower plant will have a capacity of 9.9 MW and is expected to generate an average of 40.23 GWh/yr. The electricity from the Magal Ganga hydropower plant will be sold to the monopoly government-owned utility in Sri Lanka, the Ceylon Electricity Board (CEB), through a standard power purchase agreement available to all renewable energy based power generators under 10 MW, including small hydropower. The CEB pays producers of renewable energy an amount based on short run avoided energy costs of operating thermal power stations. Currently, the marginal thermal power plants connected to the grid operate on fuel oil or diesel and the share of thermal power in Sri Lanka is expected to increase dramatically over the next ten years. The small hydropower projects do not figure in the CEB expansion plan, nor are they factored into the annual electricity supply-demand forecasts. Operation of this small hydropower plant will result in a displacement of electricity from the highest marginal cost thermal power stations.

Applying the simplified methodologies specified for small-scale projects, this small hydropower project will result in an annual emissions avoidance of 0.863 kilograms of CO_2 equivalent per kilowatt hour generated (kg CO_2e/kWh). This figure is based on the weighted average emissions of grid-connected thermal power stations operating as of August 2003. Other project benefits include reductions in NOx and SOx pollution, generation of short- and long-term local employment, and direct financial contributions to community development projects adjacent to the project site.

A.3 Project participants:

This project has three project participants.

Eco Power (Private) Ltd. (EPL), is a private Sri Lankan company that will build and operate the Magal Ganga small-hydropower facility. EPL will do this through a subsidiary company, the Magal Ganga Power Co. Pvt. Ltd., Sri Lanka, (MGPC). EPL holds a controlling interest in MGPC and EPL will retain full rights to any and all emissions reductions that result from the implementation of this project. Up to April 2003, EPL had commissioned six (6) such plants with a combined total installed capacity of 14.5 MW.

EPL is seeking registration of this small hydropower project under the Clean Development Mechanism as a means to buffer the higher investment and financial risks associated with the renewables energy marketplace in Sri Lanka.

International Resources Group (IRG), an energy and environmental management consulting firm, is the exclusive representative of EPL for the purposes of the marketing and sale of emissions reductions from the project described in this document. IRG is also the designated official contact for the proposed CDM project activities.

The IFC-Netherlands Carbon Facility (INCAF) Facility is an arrangement under which the International Finance Corporation (IFC) will purchase greenhouse gas (GHG) emission reductions for the benefit of the Government of the Netherlands using the Clean Development Mechanism. The Netherlands will use these emission reductions to help meet its commitments under the Kyoto Protocol. EPL and INCAF have entered into a preliminary agreement (a letter of intent) by which EPL agrees to sell and INCAF agrees to purchase eligible greenhouse gas emissions reductions associated with the project described in this PDD.

See Annex I for contact information.

A.4 Technical description of the project activity:

A.4.1 Location of the project activity

A.4.1.1 Host country Party(ies):

Sri Lanka

The Government of Sri Lanka ratified the UNFCCC on 23 November 1993. The country subsequently acceded to the Kyoto Protocol on September 3, 2002. Government is in process of setting up a Designated National Authority. The contact point in government is Dr. B M S Batagoda, Director, Environmental Economics and Global Affairs Division, Ministry of Environment and Natural Resources (Tel: 94-1-887452).

A.4.1.2 Region/State/Province etc.: Sabaragamuwa Province, Kegalle District

A.4.1.3 City/Town/Community etc: West of the town of Deraniyagala, on the Maliboda Estate

A.4.1.4 Detailed description of the physical location, including information allowing the unique identification of the project activity:

The Magal Ganga Small-Hydropower Project has the following GPS coordinates:

Longitude / Latitude: N 6^0 54.6’ / E 80^0 22.1’

A.4.2 Type and category(ies) and technology of project activity

The proposed project falls under the category *I.D.,* Renewable Electricity Generation for a Grid.

The project involves installation of a run-of-river hydropower plant system using well-established technologies. Run-of-river hydropower facilities are emissions-free and considered one of the best forms of low impact renewable energy available today. The civil structures at the project site consist of a gated weir designed to store a low volume of water, an intake arrangement, a channel, a desilting/forebay arrangement, a penstock, a powerhouse and a tailrace. Run-of-river hydropower has very low impact on river flow volumes and all water diverted to the powerhouse is returned to the main stream. The Magal Ganga project will run on a Francis type turbine, which has broad application around the world and is considered optimal for the particular site being developed. Detailed engineering information on the Magal Ganga project is available on request through the project operator, EPL.

All electricity generated from the project will be sold to the CEB, the monopoly government-owned power utility. The CEB will dispatch the electricity from the hydropower project to end-users connected to the national power grid.

A.4.3 Brief statement on how anthropogenic emissions of greenhouse gases (GHGs) by sources are to be reduced by the proposed CDM project activity:

The project will result in a reduction of anthropogenic emissions of greenhouse gas by displacing an equivalent volume of electricity that would otherwise be generated by the most expensive thermal power plants tied into the national grid. This expected outcome can be traced back to the expansion plans, dispatch procedures, and small power purchase policies of the Ceylon Electricity Board. These plans, procedures and policies are discussed in greater detail in Section B of the PDD.

Each year, the CEB prepares an annual energy demand forecast for each of the 8,760 hours in a year. The CEB determines the power supply forecast based on strict merit order beginning with the power plant with the lowest generation cost per kilowatt hour. Small-scale renewables, including the project in this PDD, are not included in the supply forecast. Magal Ganga will be subject to standard terms of the CEB's small power purchase agreement (SPPA). The purchase price is derived from the CEB's estimated short-run avoided cost of electricity generation, which includes the cost of fuel plus operations and maintenance. **Based on this power pricing formula for renewable energies, all small hydropower producers will only displace electricity from thermal power plants.**

The Magal Ganga small hydropower plant is expected to operate for 30 years, beginning on or around January 1, 2006. Using a weighted average emission factor of 0.863 tons CO_2/MWh for the thermal power plants in operation as of August 2003, the annual emissions reductions from the project are estimated at 34,900 tons of CO_2 as detailed in Table 1.

Table 1: Electricity Generation and Emissions Reduction Summary

Capacity rating (MW)	Capacity factor (%)	Average annual electricity generated (10^6 kWh)	Emissions factor (kg CO2/kWh)	Annual emissions reductions (tCO_2)
9.9	46.4	40.23	0.863	34,727

A.4.4 Public funding of the project activity:

Financing for the project will come from the project sponsor, MGPC and from commercial banks in Sri Lanka. No Annex I Party public funding is directly involved in the proposed project.

A.4.5 Confirmation that the small-scale project activity is not a debundled component of a larger project activity:

The proposal consists of a stand-alone small-scale hydropower plant. The proposed project is **not a** debundled component of a larger project.

B. Baseline methodology

B.1 Title and reference of the project category applicable to the project activity:

Project category title: Category *I.D.* Renewable Electricity Generation for a Grid

Reference: Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities, category I.D taken from the document version dated February 25, 2005.

The specific technology for this CDM project is hydropower as a substitute for existing fossil fuel power.

B.2 Project category applicable to the project activity:

The project involves the sale of electricity from a small-scale hydropower plant to the national monopoly grid manager, the Ceylon Electricity Board. This scenario is the only option available to the project developer and it corresponds precisely with the SSC CDM category I.D.

B.3 Description of how the anthropogenic GHG emissions by sources are reduced below those that would have occurred in the absence of the proposed CDM project activity (*i.e. explanation of how and why this project is additional and therefore not identical with the baseline scenario)*

Power generation capacity expansion is an urgent issue in Sri Lanka. Energy demand in the country has been growing at an average rate of about 7-8% per annum in the past 20 years, a trend that is expected to accelerate over the next decade. According to the CEB, further exploitation of large hydro resources is becoming increasingly difficult owing to social and/or environmental impacts associated with large-scale developments. In addition, the extensive reliance on hydropower makes the power system of this island nation overly vulnerable to drought. Severe drought led to power cuts in 2001 and the CEB has expressed its concern that cuts could occur again in the absence of capacity expansion.

The CEB is the government-owned monopoly power utility that prepares and manages the implementation of the country's power generation expansion plan. To meet the rapid growth in energy demand, the CEB expansion plan forecasts the addition of 2,690 MW in installed capacity between 2002 and 2016. The generation expansion plan takes into consideration contributions from existing and committed power facilities, and identifies additional capacity needs to meet future energy demand at the least possible generation cost. While the existing generating system is predominantly based on hydro power (69% of installed capacity), the base case expansion plan focuses on growth in thermal power. Specifically, it includes only 220 MW of hydro power additions (in 2004 and 2008) and 2,470 MW of thermal power additions. Annex II summarizes the data, methods and results of the CEB expansion plan.

The potential for small scale hydropower to access the marketplace in Sri Lanka is restricted by the fact that CEB controls access to and the terms for power production. The CEB is the major owner and operator of most power plants in Sri Lanka and is responsible for issuance of power production licenses. All power generation licenses specify that output must be sold to the CEB. Over the past five-seven years, the CEB has increasingly turned towards commissioning power plants on build, operate, own and transfer (BOOT) contracts with private operators. Note that all BOOT contracts have been for the construction of thermal power plant facilities. The CEB nevertheless maintains control of the process of identifying and licensing these new facilities. Similarly, all small-scale projects must have the pre-approval of the CEB and developers must accept the CEB's energy purchase price that changes annually -- not based on verifiable, objective criteria, but rather changes in accordance with the CEB internal calculations.

This discussion serves to highlight the dominating role of the CEB in setting the specific market and policy conditions for sector expansion. Given the tremendous growth in electricity demand, the CEB has instituted a number of policies and practices that strongly favor investments in thermal generation combined with only two new investments in large-scale, publicly-managed hydropower facilities.

As the rest of this section demonstrates, the Magal Ganga hydropower project is considered additional to the Sri Lanka energy sector emissions baseline based on an analysis of selected barriers listed in Attachment A to Appendix B, the simplified project design document for small-scale CDM project activities (SSC-PDD). Specifically, we demonstrate that the project faces significant barriers related to (i) heightened investment risk (common to all small-scale renewable investments in Sri Lanka), (ii) low market penetration of run-of-river small hydropower technology, and (iii) non-transparent procedures in the calculation of tariff schedules for small hydropower operators.

(i) investment risk barrier

Energy generation investment opportunity in Sri Lanka is relatively limited. In that limited market, small hydropower investments are subject to much higher risks than investments in thermal power projects. The difference in levels of risk are in large part linked to the power purchase terms set by the CEB. In the case of thermal power plants the CEB pays a capacity charge sufficient to cover all up-front capital costs including an agreed rate of return on the investment. In addition, separate payments are made for energy on a pass through basis. Thus, private thermal power plant operators and investors are guaranteed a no risk rate of return on their investment provided the technical aspects of the plant are sound.

In contrast, investors and operators of small hydropower facilities (and other small renewables) do not receive a capacity charge. Instead, small hydropower developers are paid based strictly on the CEB's short-run avoided costs. These avoided costs can fluctuate considerably from year to year and small hydro developers can and have in the past suffered losses in individual years. Unlike thermal power plant operators, small hydropower investors cannot claim a payment to compensate for drought-induced generation shortfalls. These arrangements act as a disincentive to investments in small-scale hydropower and argue for the additionality of the EPL investment at Magal Ganga.

(ii) Low market penetration/uncommon practice barrier

Previous studies conclude that the country has limited potential for small-scale hydropower (100-200 MW). A World Bank project document notes that installed small hydropower was 30 MW at the end of 2001, which is equal to less than 2% of total capacity in the country. Looking at the impact of the Magal Ganga project, it is clear that it makes very marginal contributions to the current and future generation mix. For example, the Magal Ganga project will generate a mere 40.23 GWh/year, which represents only 0.58% of the national annual electricity generation of 6,843 GWh in 2000 and 0.28% of the forecast output of 14,278 GWh in 2012. With an aggressive schedule for future expansion of thermal power capacity, small scale hydropower will continue to be a marginal technology in Sri Lanka and low market penetration levels, unless CDM revenues enable small hydro developers to take on the higher risks associated with investing in small run of river hydro plants.

(iii) barriers related to uncertainties in power purchase agreement conditions

Small-scale hydropower investors like EPL also face uncertainties and risks related to power purchase terms of the CEB, a monopoly utility. Each year the CEB sets a power purchase agreement price level for the wet and dry seasons. That figure is based on a 3-year running average of avoided costs. However, the CEB does not transparently demonstrate to small power producers the methodology for calculating these rolling averages. As a result, private investors have considerable difficulty predicting the direction of price changes and the degree of fluctuation from one year to the next. For example, the CEB recently announced the 2004 prices for small hydro independent power producers. Despite one of the worst droughts in decades and a steep rise in oil prices, the CEB reduced the tariff 28% below its 2003 level. The only recourse is for producers to enter into arbitration over rate calculations. However, EPL has learned from experience that arbitration can easily continue, with no resolution, for several years.

This analysis of three different barriers suggests that small hydropower investments like the one at Magal Ganga is additional to a national baseline which is clearly oriented to favor large-scale thermal investments combined with a limited number of large-scale, publicly managed hydropower investments.

Faced with the multiple investment barriers described here, EPL began in early 2000 to evaluate the possibility of improving project rates of return and reducing its financial risks through registration of the Magal Ganga project under the CDM.

B.4 Description of the project boundary for the project activity:

The boundary of the project encompasses the physical, geographical site of the hydropower plant itself.

B.5 Details of the baseline and its development:

B.5.1 Specify the baseline for the proposed project activity using a methodology specified in the applicable project category for small-scale CDM project activities contained in appendix B of the simplified M&P for small-scale CDM project activities:

The CEB, as a monopoly entity that controls the country's power grid, prepares annual demand and supply forecasts, manages most power generation facilities in Sri Lanka (except for thermal power plants introduced in the past eight years), sets the terms of small power purchase agreements and leads development of grid expansion plans.

The expansion plan (updated every two years) is designed to respond to two key concerns. First, electricity demand in Sri Lanka is growing at an average annual rate of 7-8%, which will require major investments in new generation facilities over the next decade. Second, further exploitation of large scale hydro resources (which have historically provided a large percentage of total power) is becoming increasingly difficult owing to social and/or environmental impacts associated with such developments. The CEB's 2002-2016 national expansion plan, therefore turns to thermal power plants as the primary solution to meeting the country's growing energy needs. Specifically, the CEB forecasts thermal power generation capacity to increase from its 2002 level of 751 MW to a target level of 2,754 MW in 2016. This forecast reflects a steady trend of increasing reliance on thermal power sources since the late 1990s. For example, between 1997 and 2003, the country added 724 MW of thermal power generation capacity. On the other hand, facilities less than 15 MW in size, which includes the small hydropower plants described in this PDD, are **not** incorporated into the national expansion plan. So, all small hydropower and other renewables are not part of the default power generation baseline.

Baseline uncertainties and alternative scenarios. Based on the facts regarding how CEB prepares and guides both the dispatch of current energy supply as well as the options for future energy investments, the most likely baseline scenario in Sri Lanka is the one that conforms to the CEB's current generation mix plus the base case expansion plan. The major uncertainties related to this scenario are (i) emergency conditions that lead to generation short-falls and power outages; and (ii) delays in building new power generation facilities. Either of these scenarios is likely to increase average emissions levels because (a) older, higher emissions thermal power plants will have to be used longer and for more operating hours per year, and (b) emergency diesel generators will be required to overcome generation shortfalls. A third possible scenario is a substantial increase in small-scale renewable energy or a greater investment in large-scale hydropower. However, as the earlier discussion emphasized, small-scale hydropower and wind power have very limited potential (100-200 MW for small-scale hydropower) compared to the total expected growth in generation over the next 15 years. Similarly, the country has nearly exhausted its options for large-scale hydropower because of environmental and social concerns.

The latest version of the small-scale CDM project guidelines issued on January 24, 2003, offers two options for calculating baseline emissions of category I.D. projects. The baseline for the Magal Ganga project is based on the second option identified in Appendix B of the simplified modalities and procedures for small-scale CDM.. According to this option the baseline is defined as the kWh produced by the small hydropower plant multiplied by an emission coefficient (measured in $KgCO_2/kWh$) calculated in a transparent and conservative manner as follows:

The average of the "approximate operating margin" and the "build margin: where:

(i) The "approximate operating margin" is the weighted average emissions (in kg CO2equ/kWh) of all generating sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation;
(ii) The "build margin" is the weighted average emissions (in kg CO2 equ/kWh) of recent capacity additions to the system, which capacity additions are defined as the greater (in MWh) of most recent 20% of existing plants or the 5 most recent plants.

The operating margin and build margin are derived from information available in the CEB 2002-2016 expansion plan. The plants that are included in the operating margin are those known to be on-line as of August 2003, when this PDD was first prepared. The calculations that quantify the baseline and expected emissions offsets are shown in Section E. In looking at the expansion plan, the CEB's intent is clearly to build up coal power. However, experience over the past five years shows that the CEB expansion plan rarely adheres to schedule – delays in commissioning new plants can continue for many years. Thus, to be conservative, the PDD calculates the baseline emissions based uniquely on the power plants already operational as of August 2003.

The remainder of this section is dedicated to an overview of the CEB expansion plan in order to clearly show the specific power plants that are part of the baseline. The expansion plan study results in the following base case demand forecast, which includes existing plants serving the grid. Note that only *grid-connected* facilities are included in this table. The two, small non-grid facilities do not impact the baseline issue.

Table 2: Ceylon Electricity Board base case supply forecast

Existing and Committed Hydro Power Plants		
Plant Name	Capacity (MW)	Annual Average Energy (GWh)
EXISTING		
Laxapana	335	1432
Mahaweli Complex	660	2100
Samanalawewa	120	361
Inginiyagala	11	---
Uda Walawe	6	---
Nilambe	3	---
Private hydro power	12.25	---
COMMITTED		
Kukule (End 2003)	70	303
Upper Kotmale (2008)	150	530
TOTAL HYDRO POWER	**1367.3**	**4726**
Existing, Committed and Additional Thermal Power Plants		
EXISTING		
Kelanitissa station		
Old gas turbines	96	600
New gas turbines	115	813
Steam (fuel oil)	40	250
Combined cycle plant (early 2003)	165	1253
Sapugaskanda Station		
Diesel	72	488
Diesel extension	72	444
Independent Power Producers		
Lakdhanavi	22.5	156
Asia Power Ltd	41	330
Colombo Power (Pvt) Ltd	60	420
Diesel Plant Matara (2002)	20	136
COMMITTED		
Pielstick (Jan 2003)	22	149
Independent Power Producers*		
Kelanitissa AES CCY (2003)	163	1314
Diesel Plant Horana (2003)	20	136
TOTAL THERMAL POWER	**916.5**	**5886.6**
EXPANSION PLAN ADDITIONS (in		

sequence)		
Kerawalapitiya combined cycle (2006)	300	
Gas turbine (2007)	105	
Coal Steam West Coast I (2008)	300	
Coal Steam West Coast II (2010)	300	
Coal Steam West Coast III (2012)	300	
Coal Steam Trincomalee I (2013)	300	
Coal Steam Trincomalee II (2015)	300	
Gas Turbines (2016)	175	

* IPP facilities were commissioned as build, operate and own contracts with CEB.

The table above presents the CEB's supply response to the base demand forecast. The CEB's sensitivity analysis of key parameters (overall demand, impact of demand side management measures, changes in discount rate, and a change in oil price) shows that the timing of power plant additions may shift slightly (1-3 years) but the overall trend is still one of aggressive capacity expansion.

As per the instructions for small-scale projects, the power plants considered for the baseline include only those grid-connected power facilities in operation as of the date of preparation of the PDD (August 2003). Table 3 lists the thirteen (13) power plants included for purposes of estimating the approximate operating margin of the baseline. It is important to note that both of the combined cycle plants listed in the table (JBIC and AES) are only operating the open cycle at this time and that emissions factors at the two plants are therefore higher than they would be with both cycles in operation.

Table 3: Power plants included in the Sri Lanka approximate operating margin

	CEB-operated facilities	**Capacity (MW)**	**Date commissioned**
1	Kelanitissa gas turbines (old)	96	1980-82
2	Kelanitissa gas turbines (new)	115	1997
3	Kelanitissa steam power units	40	1962-63
4	Sapugaskanda diesel plant	72	1984
5	Sapugaskanda diesel extension	72	1997-99
6	Pielstick diesel plant	22	2003
	Independent Power Producers (BOOT contracts)	165	2002-2003
7	Lakdhanavi diesel engine		
8	Asia Power Ltd diesel engine	22.5	1997
9	Colombo Power Ltd diesel engines	51	1998
10	Matara diesel plant	64	2000
11	Combined cycle plant 1 (JBIC-financed)	24.8	2002
12	Horana diesel plant	24.8	2003
13	Combined cycle plant 2 (ADB guarantee)	163	2003

The baseline build margin is based on the list of *all* grid-connected power plants currently in operation. Table 4 summarizes that list, presented in order of the year the facility entered into operation.

Table 4: Power plants considered for preparation of the build margin

Facility	**Fuel**	**Commission date**

	Facility	Fuel	Commission date
1	Old Laxapana	Hydropower	1950 & 58
2	Kelanitissa steam power units	Fuel oil	1962-63
3	Inginiyagala	Hydropower	1963
4	Wimalasurandra	Hydropower	1965
5	Polpitiya	Hydropower	1969
6	Uda Walawe	Hydropower	1969
7	New Laxapana	Hydropower	1974
8	Ukuwela	Hydropower	1976
9	Kelanitissa old gas turbines	Auto diesel	1980 & 82
10	Bowatenna	Hydropower	1981
11	Canyon hydro	Hydropower	1983 & 88
12	Sapugaskanda old diesel	Residual fuel oil	1984
13	Victoria	Hydropower	1985
14	Kotmale	Hydropower	1985
15	Randenigala	Hydropower	1986
16	Nilambe	Hydropower	1988
17	Rantambe	Hydropower	1990
18	Samanalawewa	Hydropower	1992
19	Kelanitissa new gas turbines	Auto diesel	1997
20	Sapugaskanda new diesel ext. (4 units)	Residual fuel oil	1997
21	Lakdhanavi diesel engine	Auto diesel	1997
22	Asia Power Ltd diesel engine	Auto diesel	1998
23	Sapugaskanda new diesel ext. (4 units)	Residual fuel oil	1999
24	Colombo Power Ltd diesel engines	Auto diesel	2000
25	Matara diesel plant	Auto diesel	2002
26	Pielstick diesel plant	Fuel oil	2003
27	Combined cycle plant 1 (JBIC-financed)	Fuel oil	2002
28	Horana diesel plant	Auto diesel	2003
29	Combined cycle plant 2 (ADB guarantee)	Fuel oil	2002

The build margin is defined as the lesser of the most recent 20% or the 5 most recent plants. For Sri Lanka, the build margin is therefore the last five plants added to the grid: Matara, Pielstick, Horana, and two combined cycle power plants (shown in grey in Table 4).

Section E applies this baseline list of power plants to calculate the expected GHG emissions reductions associated with the addition of the Magal Ganga small hydropower project.

B.5.2 Date of completing the final draft of this baseline section :

The final draft of the baseline was completed on September 20, 2003. A revised presentation of the baseline was completed on June 24, 2004.

B.5.3 Name of person/entity determining the baseline:

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Mr. Keck is an employee of IRG, one of the project participants listed in Annex 1 of this document. Dr. Bandaranaike is the CEO of EPL and MGPC and is also listed as a project participant in Annex 1.

C. Duration of the project activity and crediting period

C.1 **Duration of the project activity**:

C.1.1 Starting date of the project activity:

The anticipated start of construction for the Magal Ganga project is in January 2004. Project construction would continue for approximately 24 months and the project is expected to be operational on or about June 2006.

C.1.2 Expected operational lifetime of the project activity:

The project is expected to have an operational lifetime of 30 years and 0 months.

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

C.2.1 Renewable crediting period *(at most seven (7) years per crediting period)*:

C.2.1.1 Starting date of the first crediting period :

C.2.1.2 Length of the first crediting period :

C.2.2 Fixed crediting period *(at most ten (10) years)*:

C.2.2.1 Starting date *:*

The starting date is estimated to be June 1, 2006 (01/06/2006). Actual start date will be a function of the verified date of entry into operation of the power plant.

C.2.2.2 Length (max 10 years):

The anticipated crediting period is for 10 years.

D. Monitoring methodology and plan

D.1 Name and reference of approved methodology applied to the project activity:

The approved monitoring methodology for renewable electricity generation for a grid is described as follows in appendix B of the simplified M&P for CDM small-scale project activities:

"Monitoring shall consist of metering the electricity generated by the renewable technology."

This precise methodology will be applied to the Magal Ganga small- hydropower project.

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

The choice of methodology reflects the exact recommendations of appendix B for projects that generate renewable energy to a grid. The project will generate energy that will service the national grid in Sri Lanka.

D.3 Data to be monitored:

Two types of data are proposed for the project monitoring plan. The first data type is the metered output of electricity from the power plant. The second data type tracks the two major social benefits from the project: short-and long-term employment and EPL's annual financing of $2,000 for local development projects. The ID number identifies the project by name, the month and year, and the data type. Electricity output (kWh) and social benefits data (in the form of employment and annual $2,000 contribution to local development projects) are site-specific. Baseline emissions ($KgCO_2$/kWh) of grid-connected thermal power plants are common to both projects. Electricity output will be metered and recorded monthly. Social benefits will be assessed annually.

ID number (*project/date/ data type)*	Data type	Data variable	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	For how long is archived data to be kept?	Comment
Electricity output indicators									
MG-mmyy-kWh	project electricity output	Metered electricity output	KWh	M	Monthly	100%	Electronically and on paper	Two years after the last issuance of CERs for each project	Data will be aggregated semi-annually and annually
Project social benefit indicators									
MG-mmyy-E	project employment benefits	Total short- and long-term employment positions created	Person-months	M	Annually	100%	Electronically and on paper	Two years after the last issuance of CERs for each project	
MG-mmyy-P	community development project financing	Project sponsor financial contributions to local development projects	Rupees	M	Annually	100%	Electronically and on paper	Two years after the last issuance of CERs for each project	

It is not clear from CDM EB directives whether the project proponent must update the average emissions coefficient for the grid or if the baseline weighted average emissions are to remain static for the duration of the project crediting period. If updating must be done, then the following summary indicator would also be necessary:

CEB-yyyy-BE	Baseline emissions of thermal plants on the grid	Weighted average of the current generation mix (calculated as per CDM SSC guidelines)	KgCO2/kWh	E and C	Annually	100%	Electronically and on paper	Two years after the last issuance of CERs for each project	This figure will be calculated once at the beginning of each calendar year for the lifetime of the projects.

Monitoring procedures and responsibilities. The EPL projects are remarkably simple to monitor. The key point is that the only quantitative figure that requires monitoring is the actual generation of electricity from each project site. The steps to ensure this is done correctly are as follows.

First, upon completion of construction, the CEB, as the purchaser of EPL's power, requires an independent testing of the Facility and an inspection of its equipment. The CEB witnesses the testing procedure. Second, the CEB installs and maintains a primary meter for purposes of billing and payment to EPL. The Metering Equipment is located in close proximity to the Facility and is sealed. Third, the equipment is tested and calibrated annually. Both parties also have the right to request a calibration at any time if they believe that the meter is dysfunctional.

For monitoring purposes, the project will conform the standard schedule negotiated with the CEB. This involves a CEB reading of the meter at the end of each month for determination of the electrical energy delivered to and accepted by CEB under the terms of the SPPA. EPL power plant operators back this information up by taking daily (sometimes hourly) readings of generation levels and recording them on site. Monitoring data adjustments and uncertainties can only arise if the CEB does not read the meter precisely on the same date each month. In the case of payment of energy supplied, this is handled by the CEB by pro-rating the reading for the number of days in the relevant month. The same approach can be use for emissions reductions.

There is no need for special monitoring training of EPL personnel. The power plants are all automatic and the operators take down periodic readings. If there is some problem with operation, the operator contacts a senior engineer over the phone. In addition, emergencies cannot cause unintended emissions since there is no fuel used by the plants. In the event of a shut-down of the grid, the hydropower facility will automatically switch off and water will no longer be diverted to the turbine.

At the point of project verification, records of electricity generation, meter calibration and CEB power purchase receipts will be available at EPL's offices in Colombo. The verifier will also be invited to visit individual project sites to confirm the status of operations. The EPL CEO will have direct responsibility for ensuring adherence to and review of compliance with these procedures. IRG will be responsible for assisting EPL in finalizing the data reporting and recording process and in responding to any issues or corrective actions identified by the project verifier.

D.4 Name of person/entity determining the monitoring methodology:

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Mr. Keck is an employee of IRG, one of the project participants listed in annex 1 of this document.

E. Calculation of GHG emission reductions by sources

E.1 Formulae used:

E.1.1 Selected formulae as provided in appendix B:

Calculation of the project GHG emissions reductions apply a weighted average emissions factor for all thermal plants that are operational on the national grid as of August 2003. Appendix B of the simplified M&P for CDM small-scale project activities does not provide specific formulae for this calculation. See Section E.1.2 for a description of variables and formulae used.

E.1.2 Description of formulae when not provided in appendix B:

E.1.2.1 Describe the formulae used to estimate anthropogenic emissions by sources of GHGs due to the project activity within the project boundary:

There are limited estimated anthropogenic emissions of greenhouse gases due to the project activities. These Emissions stem from investment activities to construct the hydropower facilities including emissions from vehicles transporting equipment and personnel as well as emissions from use of heavy machinery and a generator at the construction site. The project construction emissions are calculated using the following formulae:

For transportation-related emissions:

Fuel for transportation (litres of fuel)	x	Distance traveled (kilometers)	x	2.68 (kg CO_2/litre)

For small engine-related emissions (cement mixer and generator):

Fuel for operation (litres)	x	Hours of operation (hours)	x	2.68 (kg CO_2/litre)

E.1.2.2 Describe the formulae used to estimate leakage due to the project activity, where required, for the applicable project category in appendix B of the simplified modalities and procedures for small-scale CDM project activities

No leakage issues arise as a result of the proposed project.

E.1.2.3 The sum of E.1.2.1 and E.1.2.2 represents the project activity emissions:

411,219 $KgCO_2$ or 411.2 tons CO2 equivalent.

These emissions occur only during the site preparation and construction stage and are to be deducted from year 1 emissions offset totals.

E.1.2.4 Describe the formulae used to estimate the anthropogenic emissions by sources of GHG's in the baseline using the baseline methodology for the applicable project category in appendix B of the simplified modalities and procedures for small-scale CDM project activities :

The baseline for the proposed project is the weighted average emissions of the current generation mix of thermal plants expressed in $KgCO_2$/year. To ensure clarity and replicability of the results, the baseline GHG calculations are broken down into five steps. All variables are assigned a letter code (A, B, C, D….) which allows for easy cross-reference to the summary table in Section E.2. that demonstrates the values obtained using these formulae.

Step 1: Calculate the relative power contribution of each thermal power plant on the grid (expressed as a percentage of total kWh generated).

This calculation is based on the following series of equations.

a. Determine expected total operating hours/year:

The following equation assumes all power plants are operating at optimal load levels. This allows for the most conservative estimate of emissions given that emissions factors tend to rise when thermal power plants operate at low load levels.

Total operating hours/year = 8760 hours/year – maintenance days – forced outage rate (%)

[D] [(A – (B*24 hours)) – ((100-C)/100)]

Data source: CEB

b. Determine maximum annual energy output (kWh/year) of each power plant

Annual energy output (kWh/yr) = Operating hours $*$ MW $*$ 10^9

[F] [D $*$ E $*$ 10^9]

Data source: CEB

c. Calculate percentage power contribution of each power plant (% of kWh/year)

Percentage power of each plant (%)	=	Annual output of each plant / Sum of output of all plants
[G]		[F / Σ F_1….n]

Step 2: Calculate the emissions factor for each thermal power plant.

a. Determine each plant's heat rate (*MJ/MWh*)

Plant heat rate (MJ/MWh)	=	(1 / plant conversion efficiency) * 3.6 * 10^3
[J]		[(1 / I) * 3.6 * 10^3]

Data source: CEB expansion plan and annual digest figures have been used for plant conversion efficiency rates; IPCC for terajoule conversion factor of 3.6 * 10^3 joules/MWh.

b. Estimate an adjusted carbon content of fuel for each power plant

Adjusted carbon content of each fuel (TC/TJ)	=	carbon content of each fuel * combustion efficiency of power plant
[M]		[K * L]

Note: CO2 combustion efficiency of all plants is assumed to be 99%.

c. Calculate emissions factor (kgC/MWh) of each power plant

Emissions factor (kgC/MWh)	=	(Heat rate * adjusted carbon content of fuel * 10^3) / 10^6
[N]		[J * M * 10^3 / 10^6]

d. Convert kgC/MWh calculation to CO_2 emissions per kilowatt hour

CO_2 emissions (kg CO_2/kWh)	=	(KgC/MWh * 44/12) / 10^3
[O]		[(N * 44/12) / 10^3]

Step 3: Calculate the emissions coefficient for the "approximate operating margin" defined in accordance with CDM Executive Board guidance as the weighted average emissions of all sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation.

a. Determine weighted average emissions of each power plant

Weighted CO_2 emissions of each plant * percent contribution of

average emissions (kg CO_2/kWh)	=	power to the grid
[P]		[O * G]

b. Sum weighted average emissions

Weighted average emissions of all plants (kg CO_2/kWh)	=	Sum of emissions factor for power plants 1 through n [Σ P_1….n]
[Q]		

This calculation results in a figure of 0.8721 kgCO_2/kWh as the approximate operating margin of all non-renewable energy on the grid at the current time.

Step 4: Calculate the emissions coefficient for the "build margin" defined as the weighted average emissions of recent capacity additions to the system, defined as the lower of the most recent 20% of plants built or the 5 most recent plants;

The build margin includes the five most recent power plants commissioned. These were identified in Section B.5 of the PDD. The result can be summarized in the following formula:

Weighted average emissions of the five most recent power plant additions to the grid (kg CO_2/kWh)	=	Sum of the weighted emissions factors for the five most recent power plants
[R]		[Σ five most recent power plants]

The above calculation results in a figure of 0.8536 kgCO2/kWh as the weighted average build margin at this point in time.

Step 5: Calculate the average of the operating margin and the build margin:

[Q + R] = (0.8721 + 0.8536) / 2 = **0.863** kgCO2/kWh

This figure represents the estimated annual emissions offset value that would result from the implementation of the Magal Ganga small hydropower project.

E.1.2.5 Difference between E.1.2.4 and E.1.2.3 represents the emission reductions due to the project activity during a given period:

Based on the above equations, for any twelve-month period, the project will result in the following emissions reductions:

GWh/ Year	Weighted average emissions reduction (kg CO_2 /kWh)	Emission reduction for a 12-month period (tons CO_2 / kWh)
40.23	0.863	34,727

E.2 Tables providing values obtained when applying formulae above:

Step 1: Calculate the relative power contribution of each thermal power plant on the grid

	Power plants	Date commissioned	Fuel source	Hours / year	Maintenance (days/yr) [a]	Forced outage rate (%) [a]	Operating hours	Capacity (MW) [a]	Annual Max. Energy (10^9 kWh/yr)	Contribution to total energy supply (% of kWh)
Variable				A	B	C	D	E	F = (D * E *1000)/10^9	G = F / (SUM: total thermal power available)
Facilities as of August 2003										
CEB-operated Kelanitissa Power Station										
1	Gas turbines (old)	1980-82	Auto diesel	8760	40	20	6248	96	0.60	9.1%
2	Gas turbines (new)	1997	Auto diesel	8760	45	8	7066	115	0.81	12.3%
3	Kelanitissa steam power units	1962-63	Fuel oil	8760	40	20	6240	40	0.25	3.8%
CEB-operated Sapugaskanda Power Station										
4	Diesel plant	1984	Residual oil	8760	44	12	6780	72	0.49	7.4%
5	Diesel extension	1997-99	Residual oil	8760	44	20	6163	72	0.44	6.7%
6	Pielstick	2003	Fuel oil	8760	44	12	6780	22	0.15	2.3%
Independent Power Producers (BOOT contracts)										
7	Lakdhanavi diesel engine	1997	Auto diesel	8760	30	8	7397	22.5	0.17	2.5%
8	Asia Power Ltd diesel engine	1998	Auto diesel	8760	30	8	7397	51	0.38	5.7%
9	Colombo Power Ltd diesel engines	2000	Auto diesel	8760	30	8	7397	64	0.47	7.2%
10	Matara diesel plant	2002	Auto diesel	8760	30	8	7397	24.8	0.18	2.8%
11	Combined cycle plant 1 (JBIC-financed)	2002-03	Naptha	8760	32	5	7592	165	1.25	19.0%
12	Horana diesel plant	2003	Auto diesel	8760	30	8	7397	24.8	0.18	2.8%
13	Combined cycle plant 2 (ADB guarantee)	2002	Fuel oil	8760	30	8	7397	163	1.21	18.3%
Capacity sub-total end 2003								932.1	6.59	100%

Step 2: Calculate the emissions factor for each thermal power plant.

	Power plants	Plant Conversion efficiency (%) [a] I	Heat rate (MJ/MWh) J = (1/I)*3.6*10^3	Carbon Content (unadjusted) (tC/TJ) [c] K	Combustion Efficiency Factor [b] L	Carbon Content (adjusted) (tC/TJ) [c] M = K * L	Emissions factor (kgC/MWh) N = J * M * 10^3/10^6	Emissions factor (kg CO2/kWh) O = (N *44/12) / 10^3
Facilities as of August 2003								
CEB-operated Kelanitissa Power Station								
1	Gas turbines (old)	0.22	16364	20.2	0.99	20.0	327.2	1.1999
2	Gas turbines (new)	0.28	12857	20.2	0.99	20.0	257.1	0.9428
3	Kelanitissa steam power units	0.23	15652	20.2	0.99	20.0	313.0	1.1477
CEB-operated Sapugaskanda Power Station								
4	Diesel plant	0.38	9399	21.1	0.99	20.9	196.3	0.7199
5	Diesel extension	0.42	8654	21.1	0.99	20.9	180.8	0.6628
6	Pielstick	0.40	8955	20.2	0.99	20.0	179.1	0.6567
Independent Power Producers (BOOT contracts)								
7	Lakdhanavi diesel engine	0.40	9000	20.2	0.99	20.0	180.0	0.6599
8	Asia Power Ltd diesel engine	0.40	9000	20.2	0.99	20.0	180.0	0.6599
9	Colombo Power Ltd diesel engines	0.40	9000	20.2	0.99	20.0	180.0	0.6599
10	Matara diesel plant	0.40	9000	20.2	0.99	20.0	180.0	0.6599
11	Combined cycle plant 1 (JBIC-financed)	0.30	12000	20.2	0.99	20.0	240.0	0.8799
12	Horana diesel plant	0.40	9000	20.2	0.99	20.0	180.0	0.6599
13	Combined cycle plant 2 (ADB guarantee)	0.29	12414	20.2	0.99	20.0	248.3	0.9103

Step 3: Calculate the approximate operating margin of non-renewable plants connected to the grid

	Power plants	Weighted average emissions (kgCO2/kWh)	Approximate operating margin emissions (kgCO2/kWh)
		P = O * G	Q
Facilities as of August 2003			
CEB-operated Kelanitissa Power Station			
1	Gas turbines (old)	0.1093	
2	Gas turbines (new)	0.1163	
3	Kelanitissa steam power units	0.0435	
CEB-operated Sapugaskanda Power Station			
4	Diesel plant	0.0534	
5	Diesel extension	0.0447	
6	Pielstick	0.0149	
Independent Power Producers (BOOT contracts)			
7	Lakdhanavi diesel engine	0.0169	
8	Asia Power Ltd diesel engine	0.0378	
9	Colombo Power Ltd diesel engines	0.0474	
10	Matara diesel plant	0.0184	
11	Combined cycle plant 1 (JBIC-financed)	0.1639	
Commissioned			
12	Horana diesel plant	0.0184	
13	Combined cycle plant 2 (ADB guarantee)	0.1675	
Approximate operating margin			**0.8721**

Step 4: Calculate the build margin

	Power plant	Date commissioned	Annual Max. Energy (10^9 kWh/yr)	Contribution to total energy supply (% of kWh)	Emissions factor (kg CO2/kWh)	Weighted average emissions (kgCO2/kWh) R
1	old laxapana	1950				
2	Kelanitissa steam power units	1962				
3	inginiyagala	1963				
4	wimalasurandra hydro	1965				
5	polpitiya	1969				
6	uda walawe	1969				
7	new laxapana	1974				
8	ukuwela	1976				
9	Kelanitissa old gas turbines	1980				
10	Bowatenna	1981				
11	Canyon hydro	1983				
12	Sapugaskanda old diesel	1984				
13	victoria	1985				
14	kotmale	1985				
15	randenigala	1986				
16	nilambe	1988				
17	Rantambe	1990				
18	Samanalawewa	1992				
19	Kelanitissa new gas turbines	1997				
20	Sapugaskanda new diesel ext. (4 units)	1997				
21	Lakdhanavi diesel engine	1997				
22	Asia Power Ltd diesel engine	1998				
23	Sapugaskanda new diesel ext. (4 units)	1999				
24	Colombo Power Ltd diesel engines	2000				
25	Matara diesel plant	2002	0.18	6.2%	0.6599	0.0411
26	Pielstick	2003	0.15	5.1%	0.6567	0.0333
27	Combined cycle plant 1 (JBIC-financed)	2002	1.22	41.5%	0.8799	0.3650
28	Horana diesel plant	2003	0.18	6.2%	0.6599	0.0411
29	Combined cycle plant 2 (ADB guarantee)	2002	1.21	41.0%	0.9103	0.3730
	Capacity sub-total end 2003		2.97	100%		
	Approximate build margin					**0.8536**

Step 5: Calculate the average emissions of the operating margin and the build margin:

Operating margin emissions	0.8721
Build margin emissions	0.8536
Average emissions (kgCO2/kWh)	**0.863**

Table footnotes:

[a] Figures are based on data in the CEB's expansion plan and the annual statistical digest for the years 1999 and 2002. Figures for independent operators are based on similar CEB-managed facilities

[b] Variables from World Bank GHG Handbook

[c] Carbon content values taken from WB GHG Handbook except for fuel oil values taken from CEB own estimates. Both sources report their figures as derived from IPCC 1996 guidelines.

Baseline emissions uncertainties. Section B.5 presented the possible alternative scenarios to the emissions estimates calculated here. The primary sources of emissions uncertainties stem from slower than expected power plant expansion and energy shortfalls related to drought or powerplant failure. Both scenarios will result in higher, not lower emissions as older power plants remain on-line longer and the gap from any generation short-fall will be filled by emergency generators. Given these alternatives, the baseline emissions calculated above are conservative estimates.

Deduction of construction-related emissions. Section E.1.2 provides formulae for calculating the project-related emissions. The following table illustrates the actual emissions resulting from the Magal Ganga project. These emissions occur only once during the construction phase of the project. The total project-related emissions from the Magal Ganga project site is 411,219 kg CO2e, or 411.2 tCO2e.

Emissions During Construction – Magal Ganga Plant

Construction Item	Units	Quantity	No of Truck Loads	Round trip distance to site (km)	Diesel Fuel Consumption of Truck (km/liter) or Liters/Hour for Cement Mixer/Generator	Total Diesel Fuel Consumption (liters)
Tunnel excavation	Cu. Met.	2,100	700	8	6	1,120
Aggregate transport	Cu. Met.	5,550	555	60	5	6,660
Sand transport	Cu. Met.	2,750	275	60	6	3,300
Cement transport	50 kg Bags	44,000	220	160	6	7,040
Steel transport	Tons	550	110	160	6	3,520
Penstock pipe transport	No.	120	60	160	5	1,920
Cement mixer	Hours	2,200			5	11,000

Generator (250 kVa)	Hours	8,000			15	120,000
Total						153,440

Total Diesel Fuel Consumed		Emissions coefficient		Total emissions	
153,440	x	2.68 kg CO_2/litre	=	411219.2	**411.22**
				kg CO_2	**tons CO_2e**

F. Environmental impacts

F.1 If required by the host Party, documentation on the analysis of the environmental impacts of the project activity:

<u>Environmental impacts</u>

Every proposed small hydro power plant in Sri Lanka requires approval from the Central Environmental Authority (CEA) which looks at both environmental and social aspects. Because of the small size of the investment, developers prepare an Environmental Report rather than a full blown Environmental Impact Assessment. This Environmental Report corresponds to a format provided by the CEA and the CEA visits the site with a team of experts and grants approval for the project if they are satisfied, after obtaining all necessary clarifications. As part of the review process the Central Environmental Authority explicitly looks into issue of the potential negative impact of any proposed small hydropower plant on the persons in the vicinity and only grants approval after satisfying itself that there are no such negative impacts.

The Environmental Report includes the following sections:

- Project description (area, weirs/intake, desilting tank, head race channel/spill, forebay/desilting tank, tunnel/penstock, power house/tailrace, access roads, and transmission line).
- List of clearances and authorizations obtained, including:
  - Approval of CEB for sale of electricity.
  - Approval from Divisional Secretary for diversion of water.
  - Approval for construction activities.
  - Approval from the Mahaweli Authority if water streams are controlled by them.
- Description of site topography, geology, hydrology, fauna and flora, upstream and downstream users, and social/cultural sensitive areas.
- Discussion of possible impacts such as erosion, land scarring, migration, construction hazards, changes in land use patterns, relocation, etc.
- Description of monitoring program and any mitigatory measures of the project.

A general comment on the nature of small-scale run-of-river hydropower projects is helpful in order to provide a clear understanding of the extremely low impact of this type of investment. Small-scale run-of-river hydropower has a very low impact on river flow volumes and all water diverted to the powerhouse is returned to the main stream. A very small ponding area occurs behind the low weir constructed across the river to facilitate the diversion of water into a channel. The volume of water accumulated behind the weir varies depending upon the site conditions but is typically less than five (5) minutes of the average water flow of the river. It is also relevant to point out that small hydropower plants do not create any type of atmospheric, noise or other pollution and they cannot therefore have any negative impact on persons living in the close vicinity of these plants.

The Magal Ganga project is somewhat larger in scale than the other plants that EPL has built or will build. The weir for this project will be built across an improved river section and include two large gates that will open automatically during floods thereby ensuring that the area of inundation during flood situations even with the weir will be no different than it is at present without the weir. An area of approximately 5 ha will be ponded up as a result of the weir whose top will be 1 meter above the present normal water level. Note that the additional land involved compared with that already occupied by the Magal Ganga river under normal flow conditions is approximately 0.1 hectares. The 1 meter height of the weir is still below the normal flood level of the river at that point and the additional area to be indundated is land that is in any event inundated periodically during normal floods. Frequent flushing will be carried out at the weir in order to hold down possible accumulation of silt due to the ponding. This resulting stored quantity of water – around 8,000 cubic meters – will be comparatively small in relation to the design flow of the plant (17 cubic meters per second) and the water flow rate in the river, and will typically only be sufficient to operate the plant for about 8 minutes. Water flows at the intake will be continuous and stagnation of water will not occur.

The CEA issued an Environmental Clearance for this project on December 22, 2002. The Environmental Report and authorization letter from the CEA are available through the offices of EPL. The CEA clearance for the Magal Ganga project reflects the overall finding that the environmental impact of the project is negligible. The general and specific conditions of approval of the EAs are in most instances generic, i.e., guidance on minimizing impacts of site preparation. Also, all projects require an environmental monitoring plan that cover surface water (not relevant in practice for run-of-river projects), flora and fauna within the river and below the diversion point, river bank erosion, and sediments upstream of the weir. One noteworthy specific condition in the CEA approval letter is that the MGPC must maintain a continuous uninterrupted flow of 500 litres/sec through a suitable opening in the weir. This opening must be uncontrolled (ie, without a gate), and must be designed to convey 500 litres/sec when the upstream water level is at the weir crest.

<u>Social and Economic Benefits</u>

Although not required in the PDD, the following summarizes the social benefits associated with the Magal Ganga project:

- During the two year construction phase of the plant the civil engineering firms undertaking the construction of the plant will hire a large number of skilled and unskilled workers from the nearby communities, thereby providing additional employment during the period.

- After commissioning the plant will have a small complement of staff of 10-15 persons including plant operators, labourers, security staff, etc. Over 50% of these persons are likely to be hired from the nearby communities.

- Additional roads have been/will be built by EPL to access the power house and weir. These roads are available for use by the local people and in some cases provide motorable access to their homes where there were only footpaths before.

- During the construction phase various additional work beneficial to the local communities will be carried out by EPL free of charge. A specific undertaking has been given to use the earth dug out for the tunnel to fill a large indentation in the ground and to create a new playground for a school which is located some distance away from the power house.

- After the project is commissioned MGPC will provide a separate Rs 200,000 ($2,000) per year budget for the local communities to use for community development projects of their choice.

- All power from the power plant will be carried to the CEB grid through the existing 33 kV distribution lines in the area. If these lines are not working for any reason MGPC cannot sell its power. In rural Sri Lanka where the MGPC plant is to be built, there are frequent breakdowns in supply and the CEB local authorities take their own time to repair these breakdowns. After MGPC builds this power plant it will pay a retainer to the local CEB authorities to cover costs associated with repair of the distribution lines. As a result the grid outage rates suffered by others consumers in the area are also reduced significantly.

- The project generates electrical energy using water. If it is not constructed the same amount of energy will have to be generated using oil which is imported. The country will therefore save on the foreign exchange required to import the oil.

G. Stakeholder comments

G.1 Brief description of the process by which comments by local stakeholders have been invited and compiled:

The entirety of the lands on which the project is located fall within Government owned tea and rubber plantation lands which have been given on long term lease by the Government to a large private plantation company. These company in turn has sub leased the land necessary for the projects to MGPC on commercial terms agreed between the parties. To the extent that the company is considered to be a stakeholder in the project its interests will clearly be looked after through the commercial agreement entered into between MGPC and the company.

The remaining local stakeholders of the project are villagers and plantation workers living in the vicinity of the projects and users of the river sections between the point of diversion of the water and its release back into the river after generation of power.
The stakeholders in this project were identified as part of the process of seeking environmental clearance to proceed with the project. To this end, meetings were held with the individuals living and working in the vicinity of the project site to explain the project's objectives and benefits. Due to the remote nature of the project there are very few local residents or structures and in this case are limited to only a few households. In this process MGPC personnel examined the potential impact of the project on persons who use water in the river between the diversion point and the point at which the water is put back in the river, an issue that is also explicitly considered in the environmental assessment of the project carried out by the CEA. The CEA has granted approval for the project only after satisfying itself that these project stakeholders are not adversely affected by the project.

In practice, there are no significant users of the water in the stretch of river in question, except for use for bathing by a few one or two families living close to the relevant rivers/streams. In these cases, the remaining waters available in the rivers after diversion, because of other smaller streams feeding into the river below the intake points and the requirement of the CEA that a minimum amount of water be released through the weir, are more than sufficient for the purpose of these families.

As a result of the consultations with local stakeholders the developer was able to design the project so that it will not interfere with current land use and economic activity.

In addition to this informal consultation process, MGPC has received approval (in writing) from the elected local government authority which represents the local community. This local government authority is called a "Pradeshiya Sabha" (PS). A typical PS in a rural area would cover about 2,000 families living in several villages. The members of the PSs are close to the village communities which they represent. In terms of the applicable regulations every small hydropower plant developer must obtain approval from the local PS prior to start of construction of a plant. Such approval has been received for the Magal Ganga plant.

G.2 Summary of the comments received:

Comments received from local stakeholders are generally positive. Participants are eager to participate as employees of the project and are enthusiastic regarding MGPC's commitment to provide an annual Rs 200,000 ($2,000) budget for the local community to use for community development projects of their choice.

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

As was stated in G.1., the stakeholder consultation process allowed MGPC to map and take into account current land uses and economic activities in the final project design.

Annex 1

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The Magal Ganga project does not require public funding.

Annex 3

SUMMARY OF THE CEB EXPANSION PLAN METHODOLOGY

The CEB 2002-2016 expansion plan study identifies the expected future power generation investments using a systematic process, summarized below. First, the CEB prepares feasibility studies on several possible project candidates. The estimated capital costs of the various candidate projects are shown, below.

Table: Capital Cost Details of Expansion Candidates Considered

Plant	Capacity (MW)	Pure Const. Cost (US$/kW)		Total cost (US$/kW)	Const Period (yrs)	IDC* at 10% of pure costs	Const cost incl. IDC (US$/kW)		Economic life (yrs)
		Local	Foreign				Local	Foreign	
HYDRO POWER PROJECT CANDIDATES									
Gin Ganga	49	389.2	2095.2	2484.4	4	18.53	461.3	2483.5	50
Broadlands	40	523.9	2219.7	2743.6	4	18.53	621.0	2631.0	50
Uma Oya	150	395.2	2001.0	2396.1	5	23.78	489.1	2476.7	50
Moragolla	27	408.2	3123.2	3532.4	4	18.53	483.9	3701.9	50
THERMAL POWER PROJECT CANDIDATES									
Coal Trincomalee	300	147.2	844.2	991.4	4	18.53	174.5	1000.7	30
Coal West Coast	300	237.2	770.7	1007.9	4	18.53	281.2	913.5	30
Gas Turbine	35	62.0	488.5	550.6	1.5	6.51	66.1	520.3	20
Gas Turbine	105	42.2	332.2	374.4	1.5	6.51	44.9	353.8	20
Combined Cycle (Kera)	150	155.7	680.5	836.3	3	13.54	175.6	767.4	30
Combined cycle	300	113.9	474.8	588.6	3	13.54	129.3	539.0	30
Diesel-Fuel oil	10	110.0	1238.4	1348.4	2	8.79	119.6	1347.3	25
Diesel-Residual oil	10	110.0	1238.4	1348.4	2	8.79	119.6	1347.3	25
Steam – Fuel oil	150	177.4	825.9	1003.2	4	18.53	210.2	978.9	30
Steam – Fuel oil	300	150.0	698.1	848.0	4	18.53	177.7	827.4	30

* IDC = Interest During Construction.

For each of the candidate plants listed in the table, the CEB prepares estimates of fixed and variable operations and maintenance costs, establishes full load efficiencies, determines heat rates for thermal plants, etc. The result is an estimate, summarized in the following table, of the specific cost of generation of each of the candidate plants used in the expansion plan study.

Table: Specific Cost of Generation of Candidate Plants used in the 2002-2016 Expansion Plan.

PROJECT/PLANT	CAPACITY (MW)	SPECIFIC COST (Jan 2001 border prices)	
		USCts/kWh	Rs/kWh
HYDRO			
Gin Ganga	49	6.86	5.49
Broadlands	40	9.05	7.24
Uma Oya	150	10.04	8.03
Moragolla	27	10.27	8.22
THERMAL			
Coal Trincomalee (80% PF)	300	3.99	3.19
Coal West Coast (80% PF)	300	4.13	3.31
Combined Cycle (60% PF)	300	5.70	4.56
Diesel-Fuel Oil (80% PF)	10	6.35	5.08
Diesel-Residual Oil (80% PF)	10	5.82	4.66
Steam-Fuel Oil (80% PF)	150	6.19	4.95
Steam – Fuel Oil (80% PF)	300	5.45	4.36
Gas Turbine (30% PF)	35	9.91	7.93
Gas Turbine (30% PF)	105	8.47	6.78

The CEB uses the System Simulation package (SYSIM) developed during the Master Plan Study in 1989 and the Energy and Power Evaluation Program (ENPEP), developed by the International Atomic Energy Agency (IAEA) to conduct expansion planning studies. The ELECTRIC module of ENPEP is used to determine the optimal generation expansion plan.

The following assumptions are applied to calculate the least-cost expansion plan:

- For the most recent study, the period of analysis is 2002-2021.
- All analyses were performed based on economic border prices for investments and operations.
- The exchange rate used is 80.04 Rs/US$ (rate as of 1st January 2001).
- All costs are in constant January 2001 US Dollars.
- It is assumed that the power plants are commissioned at the beginning of each year.
- Capital costs are shown in two components, foreign cost and local cost.
- A conversion factor of 0.9 is applied to all local costs to obtain a border price equivalent.
- No taxes and duties are added to costs.
- Whenever results of project feasibility studies were available, these figures were adopted after adjustment to 2001 values.
- The fuel prices used are taken from World Bank price projections published in September 2001.
- The average loss to the economy due to electrical energy not supplied is estimated at 54.51 Rs/kWh or 0.68US$/kWh (in 2001 prices). This figure comes from an evaluation published in 2000.