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Baseline recommendations for greenhouse gas mitigation projects in the electric power sector

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Abstract

The success of the Clean Development Mechanism (CDM) and other credit-based emission trading regimes depends on effective methodologies for quantifying a project's emissions reductions. The key methodological challenge lies in estimating project's counterfactual emission *baseline*, through balancing the need for accuracy, transparency, and practicality. Baseline standardisation (e.g. methodology, parameters and/or emission rate) can be a means to achieve these goals. This paper compares specific options for developing standardised baselines for the electricity sector—a natural starting point for baseline standardisation given the magnitude of the emissions reductions opportunities. The authors review fundamental assumptions that baseline studies have made with respect to estimating the generation sources avoided by CDM or other emission-reducing projects. Typically, studies have assumed that such projects affect either the operation of existing power plants (the *operating margin*) or the construction of new generation facilities (the *build margin*). The authors show that both effects are important to consider and thus recommend a *combined margin* approach for most projects, based on grid-specific data. They propose a three-category framework, according to projects' relative scale and environmental risk.

Keywords: Climate change; Baselines; Clean Development Mechanism

1. Introduction

The threat of global climate disruption resulting from greenhouse gas emissions is rapidly emerging as one of the great sustainable development challenges. The Kyoto Protocol to the UN Framework Convention on Climate Change (UNFCCC) represents an important step toward meeting this challenge. The Kyoto Protocol creates two distinct types of market-based mechanisms to assist its Annex I Parties (the industrialised and transition economies) in achieving their binding emissions targets. The first, international emissions trading, is an *allowance* trading ("cap-and-trade") system, whereby emissions rights can be traded among Annex I countries. The second type is *credit* trading, embodied in the Clean Development Mechanism (CDM) and Joint Implementation (JI), which enables Annex I countries to purchase the emission reductions generated by specific project activities in developing (non-Annex I) countries, and in other Annex I countries, respectively.

The success of all credit trading regimes depends on clear rules: technical, methodological, and administrative processes that ensure credits are awarded to projects in a fair, consistent and transparent manner. One of the principal challenges in awarding credits for GHG mitigation projects is the determination of emission baselines. A project's emissions baseline is a best estimate of what would have occurred in the project's absence. Emission reductions are then calculated as the difference between a project's emissions and its baseline. These credits are termed Certified Emission Reductions (CERs) in the case of CDM and Emission Reduction Units (ERUs) in the case of JI.

Determining a project's emission reductions poses two related and difficult counterfactual questions: (1) Is the project *additional* to normal practice? In other words, is it being implemented because of the incentive provided by the credit-trading program? ("the additionality question"); (2) Assuming the project is additional, what is the quantity of net emissions reductions relative

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to what would have occurred in the absence of the proposed project? ("the baseline question"). These two questions are inseparable as both involve an examination of the counterfactual situation. While presenting ways to address additionality, this study focuses on baselines.

Since baseline methods determine how many emission credits a project will accrue, much is at stake. Systematic error in baseline estimation could result in a variety of undesirable outcomes. Overly lax (high) baselines will simply increase global emissions, since spurious credits will enable increased emissions without compensating emissions reductions.[1] On the other hand, baselines set too stringently (low) will reduce crediting and the economic incentive for GHG mitigation projects, and could result in lost opportunities to invest in truly additional GHG reductions in developing countries, and presumably higher costs for compliance with emissions targets.

As the Executive Board (EB) of the CDM (or any other body concerned with the development of project rules) takes on the task of developing and recommending "general guidance on methodologies relating to baselines (UNFCCC, 2001)," it must balance these concerns, while ensuring the reliability, consistency, and transparency with manageable transaction costs. Environmentally beneficial projects might not be initiated if developers perceive the transaction costs and uncertainty involved with baseline determination as a major barrier. While most of the projects under the Activities Implemented Jointly (AIJ) pilot phase and other early credit trading projects have conducted project-specific baseline studies, they have not been particularly transparent or consistent and were often costly (UNEP/OECD/IEA, 2001; Parkinson et al., 2001). As a means to address these and other issues, the notion of baseline standardisation has gained considerable attention and support. Baseline standardisation (i.e. standardised emission rates, parameters and/or methodologies), if done well and tailored to appropriate project types, can simultaneously promote consistency, limit the opportunities for gaming (selecting advantageous baselines), and reduce transaction costs. With this in mind, the Conference of the Parties (COP) to the UNFCCC also tasked the EB to provide specific guidance on: "the appropriate level of standardisation of methodologies to allow a reasonable estimation of what would have occurred in the absence of a project activity wherever possible and appropriate (UNFCCC, 2001, Appendix C)."

The electricity sector is a natural starting point for baseline standardisation because of the sizeable market opportunities in this sector,[2] the diversity of project types that require an electricity baseline,[3] the need for simplified procedures for small-scale electricity projects, and the substantial research on and experience with standardised electricity baselines.

1.1. Electricity baselines: literature and experience

Over the past 5 years, research, case studies, and pilot projects have generated substantial literature and lessons learned related to electricity baseline methodologies. This experience is summarised in Table 1. Many projects have established baselines using project-specific, scenario analysis methods. Scenario analysis involves creating a set of plausible scenarios reflecting what would happen in the absence of a CDM investment (including the project itself), and then identifying the most likely baseline scenario among them. This baseline identification process can either be done on an ad hoc basis (e.g. as often the case for AIJ projects) or using more well-defined and reproducible methods, such as regulatory and policy assessment, investment analysis, market barrier analysis, risk analysis, and conservatism principles.[4] Once the most likely baseline scenario is identified—e.g. a lower-efficiency power plant that will no longer be built as a result of the project—then it can be translated into a baseline emission rate in g CO_2 eq/kWh (grams of carbon dioxide equivalent per kilowatt-hour).

However, such ad hoc project-specific methods have tended to result in inconsistent and non-transparent baselines, and can introduce costs and uncertainties that some projects would not be able to bear. Thus, this paper focuses on opportunities and approaches for standardised baseline methodologies (actual values or algorithms to determine them, often referred to "multi-project" baselines), based on pre-determined notions of what the baseline scenario is for all relevant electricity projects. Standardised baseline approaches have already been adopted by the Dutch CERUPT and the Oregon Climate Trust to award emission credits to electricity

[1] Note this concern exists largely for the CDM. In the context of JI, where host countries have a fixed emission target, overly high baselines will simply reduce the host country's access to emissions rights cover domestic emissions and to sell through emissions trading.

[2] Based on International Energy Agency data (IEA, 2002), roughly 560 GW of new power plants will come on-line in non-Annex B countries 1997–2010, producing roughly 2000 Mt C (or 7200 Mt CO_2) during that time.

[3] For the purposes of this analysis, electricity projects encompass activities that affect either power supply or demand, including new generating units, retrofits at existing facilities, off-grid electricity, energy efficiency, and cogeneration. In addition to requiring a baseline for avoided electricity generation, energy efficiency and cogeneration activities also require a baseline for on-site energy consumption levels, which is not addressed here. Thus, the principal focus of this paper is on the *supply-side* of the electric power sector.

[4] Sources include ERUPT (2001), CERUPT (2001), PCF (2000a, b, 2001a, b), UNIDO (2001), USDOE (2001), and many others.

Table 1
Emission credit trading programmes and efforts to standardise electricity baselines

Sponsoring Institution or Emissions Trading Initiative	Relevant documents	Executed credit trades/sales	Standardisations discussed/proposed (D) or implemented (I)
Activities Implemented Jointly under UNFCCC	Project documents available at UNFCCC website	Not under UNFCCC	None (Projects used ad hoc project-specific methods)
Prototype Carbon Fund (PCF)	Several baseline studies for electricity projects. Methodology papers	Yes	None (Learn-by-doing approach and use of several scenario-based, project-specific methods)
ERUPT	Step-wise guideline documents, including specific to the electricity sector	Yes	Parameters for project-specific scenario analysis. T&D loss factors (I)
CERUPT	Similar to ERUPT	Yes	Parameters for project-specific scenario analysis Electricity baseline emissions rate for small-scale projects (I) T&D loss factors (I)
OECD/IEA (for the Annex I Expert Group on the UNFCCC)	Research papers and books	No	Several standardised electricity baseline methodologies (D)
UNEP/OECD/IEA	International Baseline Workshop and Proceedings	No	Recommendations on elements of standardised electricity baselines (D)
Japanese Government Working Group	"Simplified Methodology" proposed	No	Decision trees for guiding project-specific baseline scenario analysis
PROBASE/EU	Research Papers	No	Standardised electricity baseline methodologies (D)
US government and national laboratories) (EPA, DOE, LBNL	Research papers Case studies in non-Annex I countries	No	Several standardised electricity baseline methodologies (D)
UNIDO	Research papers on industrial projects Case studies in non-Annex I countries	No	Decision trees for additionality testing/ baseline scenario selection (D)
Oregon Climate Trust	Guidelines available	Yes	Electricity baseline emissions rate (I)
US Voluntary Reporting (1605b)	Guidelines available	No	Electricity baseline emissions rate (I)
Canadian Greenhouse Gas Emission Reduction Trading Pilot	Research papersAlberta Emissions Quantification Working Group Report	Yes	Recommended electricity baseline method ( )
Mexico (ATPAE/ CONAE)	Research papers, recommended baseline methods, decision process	No	Electricity baseline emissions rate (D/I)

projects, by various voluntary programs (such as the US 1605b program), and are under active consideration in Mexico (ATPAE/USAID, 2002). In each case, a specific methodology is used to calculate a corresponding electricity baseline emission rate (in g CO_2eq/kWh), which is then available to all approved projects that are judged eligible for the pre-determined baseline. In the case of the CERUPT procedures, for instance, only small-scale (fast track) projects are eligible for such standardised baselines.

Several institutions, including OECD/IEA, USEPA, USDOE, UNEP, and others have sponsored research and case studies to evaluate alternative methods for developing electricity baselines that are sufficiently accurate, applicable across many different contexts, and feasible given data and institutional constraints (OECD/IEA, 2002; Ellis and Bosi, 1999; Sathaye et al., 2001; USDOE/SAIC, 2001; Lazarus et al., 1999, 2000). These reports have raised a number of issues that need to be addressed to standardise baselines: basis (underlying suppositions about sources of avoided generation), geographical aggregation, dynamics, and stringency. These issues are discussed further in Section 2.

1.2. Criteria for evaluating baseline methodologies

The baseline literature includes several key criteria to use in evaluating baseline methods and selecting specific baseline scenarios. Most of these criteria are well summarised in a few lines from the COP7 decision that, "recognising the need for establishing *reliable*, *transparent* and *conservative* baselines...", issues terms of reference for baseline methodologies in order to: "promote *consistency*, *transparency* and *predictability*…; provide *rigour* to ensure that net reductions in anthropogenic emissions are real and measurable, and an *accurate* reflection of what has occurred within the project boundary…; ensure *applicability in different geographical regions* and to those project categories which are eligible in accordance with decision 17/CP.7 and relevant decisions of the COP/MOP…; [and] be *conservative* [in standardisation] in order to prevent any overestimation of reductions in anthropogenic emissions." (UNFCCC, 2001, App. C, (a)(ii)–(iv) and (b)(v)) These recommendations echo criteria that have been presented in several preceding baseline studies (e.g., Ellis and Bosi, 1999; UNIDO, 2001; Lazarus and Kartha, 2001). This study used the following criteria to judge baseline methodologies:

- *Accuracy and rigour*: To ensure that reductions are real and measurable and projects are additional;
- *Transparency*: To enhance credibility by making methods and assumptions clearly explained and to make baseline reports accessible for review;
- *Cost-effectiveness*: To ensure that the transaction cost of baseline development is justified by its contribution to a more accurate baseline, and acceptable given the scale of the project and the economic value of credits likely to be awarded;
- *Maintenance of adequate incentives*: To ensure that baselines are not unduly stringent, thereby discouraging CDM projects that would in fact be additional and beneficial to host countries in terms of sustainable development;
- *Practicality*: To account for data and institutional constraints and ensure ease of implementation;
- *Wide applicability*: To enable use across many national contexts;
- *Consistency*: To level the playing field among similar projects in similar circumstances, and to assist the verification/validation process;
- *Reproducibility*: to yield similar results each time method applied, as a sign of objective, systematic procedure;
- *Conservatism*: to promote environmental integrity, e.g. by selecting the lower end of a range of plausible baseline emissions if there is uncertainty.

Clearly, tradeoffs among these criteria must ultimately be made. One key criterion for this study is "practicality", as data availability is essential for developing practical baseline recommendations.

1.3. A typology of potential GHG mitigation projects in the electric power sector

Electricity baseline procedures need to anticipate and address a wide diversity of projects—from remote and off-grid solar installations to new, large-scale power plants to refurbishment of aging infrastructure to innovative efficiency programs. Table 2 provides a scheme for classifying the various project types, and matches types of electricity projects with recommended baseline methods. As mentioned above, it will be more challenging to develop simple, comprehensive emission baseline methods for energy efficiency and cogeneration projects. This analysis considers, for these projects, only the part of the baseline exercise dealing with emissions savings attributable to displaced electricity generation.

2. Electricity baseline issues and options

2.1. Build, operating, or combined margin?

Many studies have pointed out the need for emission baselines to take into account what is happening at the *margin* (rather than on *average*), as it is a better reflection of "what would happen otherwise" (e.g. Lazarus et al., 1999; OECD/IEA, 2002). But there are different methods and approaches to estimate this *margin*.

The choice of baseline for electricity projects often revolves around the choice between *operating margin* versus *build margin*, and the question of which best represents the source(s) of avoided generation. Some baseline scenarios or methodologies reflect the belief that a given project will have no effect on other power sector investments, either because it is too small or because it brings additional investment to a sector that is short on capital for new power plant investments. These scenarios are *operating margin* scenarios—they assume that the principal effect of a new project would be on the operation of current or future power plants.

In contrast, some baseline scenarios and methodologies implicitly presume that a proposed project is an alternative to investing in another specific new source of electricity (e.g. "if not this geothermal facility, a coal plant would be built"), or, if not displacing another source of electricity, the project delays its online date. Indeed, this "delay effect" is a reasonable assumption where: (a) there is a planned or unplanned sequence of new facilities to be built, and (b) the timing of construction is affected by the need to balance supply and demand, either through maintaining the reserve margin above a threshold level (in planned systems) or through the price signals created by rising demand that motivate new investments. By increasing generation or reducing load, a new project will increase reserve margins or dampen price signals, delaying the timing of the series of planned or market-induced investments in new power supply, as illustrated in Box 1. All of these scenarios are, in essence, *build margin* scenarios, since

Table 2
Typology of potential CDM electricity projects

Code	Project type	Examples
Fast track (FT)[a]		
FT1a	New renewable on-grid electricity projects (<15 MW)	10 MW windfarm
		5 MW hydro facility
FT1b	New remote and off-grid renewable electricity projects	Solar PV home system project
		Remote hydro mini-grid
FT2	Energy efficiency projects (<15 GWh/yr)	Efficient motor replacement program
FT3	Other small projects (<15 $kTCO_2eq/yr$)	Gas-fired combined heat-and-power project
		Fuel switch from higher carbon to lower carbon fuels (e.g. gas or biomass)
Non-fast track (NFT)[b]		
NFT1a	New/Greenfield (zero or low carbon)	New 100 MW windfarm
		New 500 MW hydro
NFT1b	New/Greenfield (fossil)	New 500 MW supercritical (high-efficiency) coal plant
NFT2	Energy efficiency	Major industrial process change (>15 GWh/yr saved)
NFT3	Cogeneration	300 MW combined heat-and-power project
NFT4a	Existing/brownfield—Higher efficiency or increased output, same fuel	Repowering a single cycle gas-fired turbine to combined cycle operation
		Retrofitting and improving performance at poorly performing fossil-fired plant
		Adding turbines to an existing hydro dam
NFT4b	Existing/brownfield—Fuel switch	Converting coal or fuel oil plant to burn gas
		Co-firing biomass at a large coal plant

[a] The sizes shown for "fast-track" projects reflect the decision in the Marrakech Accords on simplified modalities and procedures for small-scale CDM projects. Further guidance from the CDM Executive Board is expected on the project types and sizes eligible under each of these categories. "Non-fast track" projects are those currently excluded from this decision.

[b] Non-fast-track (NFT) project types might conceivably include some off-grid projects, such as large-scale generation for industrial facilities that choose to self-generate their electricity. Additional work would be needed to examine baselines for such projects.

they assume that the project affects what and/or when new facilities will be built.

It is important to consider the "delay effect", especially given that it is more likely to occur under most power sector circumstances than the "cancel effect" (i.e. not building another plant altogether)[5]: the effect of a demand-reducing or supply increasing project should be manifested in the delayed construction, even if slight, of a series of new facilities, not just the next plant in line. Therefore, build margin baselines should ideally reflect a composite of power plant investments, and not necessarily a single one. As a consequence, unless a project can be clearly shown to displace another specific power plant (e.g. a high-efficiency coal plant being built instead of a lower efficiency one at the same site), standardised *build margin* baseline emission rates that are drawn from a mix of likely capacity additions are preferable to "single plant" baselines.

Another implication of the delay effect is that, up until the time at which the delay effect takes hold—and it could take several years if there are plants with long lead times under construction, the CDM project could have an effect only on the *operating* margin. This in turn suggests that the ideal baseline approach might be one that combines both the *operating* and *build* margin effects, evolving from the former in early years, toward the latter in later years.

[5] It can be argued that CDM projects, especially smaller ones, will have no effect whatsoever on other plant construction in situations where local price signals and reserve margins are not the main drivers for new investment. Indeed in many countries, capital availability and other intangible factors (e.g. politics) may be a principal driver. These situations will generally be difficult to identify and may be short-lived.

2.2. Baseline dynamics and crediting lifetimes

There are several issues of baselines "dynamics" that have been discussed extensively in the literature (OECD/IEA, 2002; Lazarus et al., 2000), most notably:

- Should a standardised baseline be determined on an *ex ante* or *ex post* basis?
- Should an ex ante baseline emission rate be fixed or perhaps decline over time?

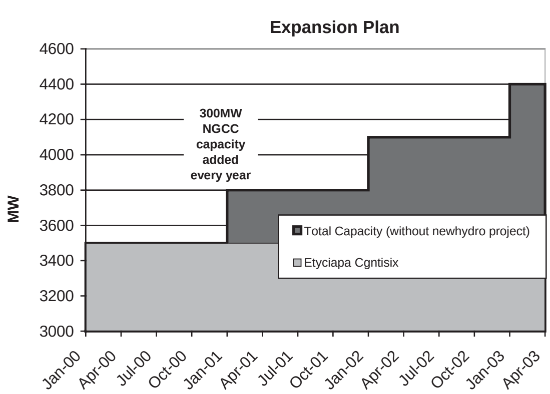
Box 1
The delay effect: how even small projects can affect new construction

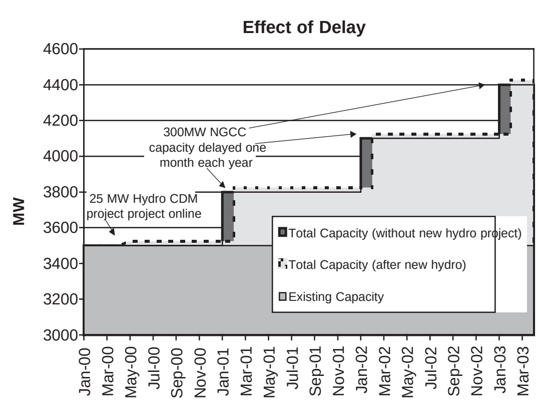
It is sometimes argued that emission reduction projects, especially smaller energy efficiency and renewable energy projects, will have little or no effect on what plants are built or retired, and thus avoid generation only from existing plants. Such an argument suggests that for smaller projects the *operating* margin provides a more relevant baseline than the *build* margin. However, it is worth examining this assumption more closely.

Consider, for example, a power system of 3500 MW total generating capacity. Due to rapid growth in electricity demand, a new 300 MW natural gas combined cycle (NGCC) plant is expected to be built approximately every 12 months. This expectation might be based on an expansion plan in centrally-planned single utility system (e.g. Mexico or India), or on expected response to price signals in a competitive wholesale electricity market (e.g. Chile or Argentina). This expansion is reflected in the chart on below.

Now assume a new 25 MW hydro project comes online, as shown by the dotted line beginning on the right of the second chart below, which shows total system capacity versus time. (In this fictive example, the hydro plant begins operating in May of year 0.) This project adds about 1/12th the electricity of a new NGCC plant, a small amount, but sufficient to delay the need for this new plant by one month. In a planned system, delaying the series of plant additions by one month could save the utility (and its ratepayers) a considerable sum in plant operating costs and interest payments on the capital required. In a fully-functioning competitive market situation, the addition of the hydro plant will delay the time at which supplies get tight by about one month, and dampen price signal sufficiently for investors to delay their investments by one month on average.

If this delay does occur, as shown in the right-hand chart, the whole series of expected plant additions is put off, each by about one month. By displacing a 300 MW NGCC for one month each year, the 25 MW hydro plant is avoiding the equivalent of 25 MW of NGCC each year (300MW x 1/12 year). In other words, in this simplified example, there is a one-to-one correspondence between the amount of credit generation and avoided generation at the *build* margin, beginning with the delay of the first NGCC plant. Reality of course is more complex. Due to the inertia of power system investments, it may take a few years for a project to actually have this effect, and in the meantime it might be affecting only the operating margin. Yet the effect demonstrated by this example should hold in most power systems: even small projects should have some effect on displacing electricity generation from new plants on the *build* margin.





- How long should a given baseline methodology apply before being revised for a given project?
- How often should one update ex ante standardised baseline emission rates for new projects?

While many of these questions may still not been fully answered for JI/CDM projects, they can at least be put to rest for the time being in light of recent COP decisions, and some can be answered by relying on the recommendations of the May 2001 UNEP/OECD/IEA baseline workshop (UNEP/OECD/IEA, 2001) and insights from baseline studies. The COP decision on crediting periods[6] gives CDM project proponents the choice between three consecutive 7-year crediting periods, with baseline revisions possible at the start of the second and third periods, or a single 10-year crediting period. These decisions can be interpreted as a compromise between investor certainty (providing fixed periods for crediting) and environmental integrity (by fully discounting any emission reductions beyond

[6] Decision 17/CP.7. www.unfccc.int/cdm/rules/modproced.html.

years 10 or 21 in response). These decisions can be interpreted as implicitly favouring ex ante baselines, which can only be revised for a given project in years 8 and 15, if the proponent selects the 21-year crediting period. This seems consistent with the COP7 decision on the CDM stating that "any revision to an approved methodology shall only be applicable to project activities registered subsequent to the date of revision and shall not affect existing registered project activities during their crediting periods" (Decision 17/CP.7, paragraph 39 of the Annex). These ex ante baselines could take the form of either specific emission intensities or algorithms for calculating emissions intensities. While there may still be scope for an ex post approach, which can be quite well suited to standardised *operating* margin baselines, it is not further considered here

2.3. Geographic aggregation

Experts at the May 2001 UNEP/OECD/IEA baseline workshop concluded that for grid-connected projects, baselines should account for regional, national, or sub-national grid characteristics, as defined by transmission, power pooling, or other operational considerations. Ideally, then, electricity baselines should be specific to individual "grid areas", and in that way more accurately reflect the generation (and if relevant, transmission and distribution (T&D) losses) that a project would most likely avoid, based on its location. Differences in carbon emissions intensity among distinct regions of a country can often be quite significant (example here, e.g. North/South Brazil, East/West China, North/South India), due to different resource availabilities and fuel prices. The challenge is to find a workable definition of a grid area that can be based on data suitably disaggregated to allow baselines to be calculated in this manner.

The grid area can be defined by transmission constraints, planning areas, power pooling agreements, or commonly accepted norms for what constitutes a well-interconnected system that is operated in a joint manner. A country may comprise more than one such grid. For example, Mexico currently contains four semi-autonomous regions for grid operation and power plant operations. Largely due to limited transmission connections among them (Baja California South, Baja California North, the Northwest, and the rest of the country), and the availability of detailed data, baselines could be developed separately for each grid (ATPAE/USAID, 2002). Or multiple countries may plan and operate their electricity systems in a joint fashion. There are several power pooling associations around the world, including SIEPAC (Electric Interconnection System for Central America) and SAPP (the South African Power Pool). Though such associations often facilitate power sales and joint resource development, they rarely act to operate or dispatch the entire system in a joint manner. The appropriateness of aggregating baselines to regional power pool levels needs to be evaluated on a case-by-case basis and to be based on the mutual consent of all countries involved.

Therefore, we recommend that while the default level of geographical aggregation be at the country level, host countries, for the purposes of electricity baselines, be allowed to: (a) define separate sub-national grids; (b) combine with other countries with whom power pooling or other joint planning/operation agreements exist. The resulting *grid area* definitions would need to be supported by evidence of management of the individual grid areas on joint (multinational) or separate (sub-national) basis, and adequate transmission interconnections (multinational) or significant transmission constraints (sub-national).

2.4. Project boundary issues

Another fundamental question is what project boundaries to assume for electricity projects, i.e. what emissions and emission sources should be counted. Since electricity projects can result in emissions reductions or emissions savings distant from the site of project activity—e.g., a project to replace a fossil fuel with biomass fuel may cause the absorption of carbon in a distant forest—geographic and temporal limits for emissions accounting or "boundaries" are necessary. The question of which emission sources to include in the accounting for emissions reductions has been widely discussed (WBCSD/WRI, 2002; OECD/IEA, 2002; Lazarus and Kartha, 2001). It is a question that relates equally to the project and its baseline, and has important implications for how projects are monitored.

Various principles have been suggested to guide which emission sources and sinks to include: materiality (or "significance"), control over emissions and the maintenance of proper incentives, minimising leakage, avoiding double counting, and practicality. It is generally accepted practice to include all direct on-site CO_2 emissions and similarly to include those direct off-site emissions related to electricity (for energy efficiency projects) or district heat production (Ellis, 2002).[7]

It also makes sense for some types of projects (e.g. distributed generation) to account for avoided T&D losses in their baseline (Martens et al., 2001b). But for most grid-connected projects, T&D would not need to be counted as the losses would be the same for the CDM project as for the project "that would happen otherwise"—essentially creating a "wash".

[7] For a description of direct vs. indirect impacts see ERUPT (2001). An example of an indirect on-site impact would be rebound effects such as increased heating that may result from of an insulation program. Indirect off-site impacts include negative and positive leakage, such as economy-wide response to project-induced changes in market prices or project-induced increases in the penetration of low carbon technologies in other regions.

Table 3
Partial list of potentially significant direct, on-site and off-site emissions

Projects avoiding↓	Boundary impacts	Issues to consider	Current typical practice (for baselines)
Delivery of electricity across			
Distribution "D"(low voltage) wires	Average avoided distribution losses	Applies to most residential and commercial efficiency and distributed generation projects	Include combined T&D loss fraction, based on national loss figures (e.g. CERUPT/ ERUPT) (Do not include "non-technical losses")
Transmission "T" (high voltage) wires	Average avoided transmission losses	T losses typically a small fraction of overall T&D losses. Efficiency or CHP at large high voltage industrial customers usually avoids only the T losses	
Grid electricity production from			
Coal	Coal-bed methane emissions, where release rates are high	Potential for double-counting with methane capture projects	Rarely, if ever, counted
Natural gas	Methane releases from T&D, production, and storage	Potential for double counting with methane capture projects	Rarely, if ever, counted
Oil	Methane from associated gas venting and flaring, especially where rates are high	Given the global oil market it may be impossible to effectively link consumption to specific production sites	Rarely, if ever, counted
Biomass	Carbon flows and energy use in feedstock production and transport	Impacts from land conversion, and harvesting of biomass feedstock	Mixed. Often argued that sustainably harvested biomass has zero net C emissions
Hydroelectric facilities	Methane emissions where sited on terrain with decaying biomass[a]	Unlikely that project will avoid construction of a specific hydro plant Large uncertainties related to CH_4 emission calculations	Limited experience

[a] Though hydropower is generally considered to be a zero-carbon resource, flooding of reservoirs containing substantial biomass (subject to anaerobic decomposition) and can lead to significant methane emissions, especially where the ratio of flooded area to power production is low (e.g. $<0.5\,W/m^2$) (Rosa and dos Santos, 2000).

Other direct off-site emissions, as illustrated in Table 3, are rarely included in *baseline* emission calculations, even though they may be in *project* emissions calculations. In other words, upstream methane releases might be counted for a project that generates electricity from natural gas, whereas a wind project might not include the methane emissions associated with the natural gas generation assumed to be in the mix of avoided electricity sources forming the baseline. We recommend this approach (i.e. excluding direct off-site emissions) for electricity supply projects, as it is practical as well as conservative.

Indirect emissions are typically more difficult to quantify. Though they can have major impacts on calculated emission reductions for some land-use related projects (e.g. leakage in the case of some avoided deforestation projects), these will rarely have a predominant impact on electricity projects (Lazarus and Kartha, 2001). Therefore, for reasons of practicality as well as conservatism, we recommend that only transmission and distribution losses be accounted for in terms of indirect emission sources for energy efficiency projects and distributed generation projects. Some indirect and off-site emissions could also be added to the baseline on an *ex post* basis, as the result of monitoring and verification work, but this warrants further examination.

In terms of calculating a T&D loss factor (total generation/total delivered electricity), we recommend using the locally available data for the grid area (see Section 2.3), and where absent to use nationally reported data. Non-technical losses (i.e., theft) should not be counted in calculating the T&D losses.

2.5. Operating margin methods

As mentioned earlier, the operating margin approach presumes that a project's predominant effect is to modify the operation of existing power plants. Operating margin approaches have been used for numerous emission reduction projects.[8] Operating margin approaches evaluate which plants are the last to be

[8] Examples include: Ilumex (Mexico, World Bank AIJ), PROCEL (Brazil, GEF), Liepaja landfill (Latvia, PCF), Chacabuquito Hydro (Chile, PCF), Dona Julia Hydro (Chile, USIJI), and Aeroenergia Wind (Costa Rica, USIJI).

deployed to meet demand at any given time. These approaches require information such as: historical dispatch data (which plants were operated during which hours), stacked-resource load curves that assemble this data in merit order, or the hourly operating cost of different plant types (or their bid prices in competitive environments). This information is available in a number of countries, but restricted in many due to confidentiality agreements. Where these data are unavailable or more straightforward approaches are desired, simpler methods have been used to approximate the operating margin.

Below we discuss and then compare four discrete operating margin approaches, starting with the simplest. All represent algorithms or methodologies (e.g. using models) that can be applied periodically (e.g. annually) within a host country to develop *standardised baseline emission rates* (g CO_2 eq/kWh) for projects implemented in that country. Such algorithms could provide an unambiguous formula from which project developers could estimate the future CERs their project might earn. This is likely to present limited risk to investors, since the baseline emission rates are unlikely to vary much on an annual basis given the inertia of power systems, especially larger ones.[9] The data required by each algorithm is discussed below, as well as the information sources from which the data can be obtained.

2.5.1. Generation-weighted average emissions rate of all plants

The prime example of a simple and straightforward approach to assessing the operating margin is simply to assume that a project avoids a proportional fraction of all generating units on a system. This method has been applied for the US Voluntary Reporting (1605b) program (state-level averages), and some Canadian (GERT) projects. The required data are usually available within host countries, and if not, they can be drawn from international data (e.g. IEA). The results are easy to calculate on an annual basis. The most obvious concern with this approach is that it biases the baseline toward existing, and often older, baseload plants and other low running cost power plants (e.g., hydro, nuclear, and geothermal) that provide a considerable amount of electricity in many countries; these units are the least likely to be displaced by new projects. This can be inaccurate, especially in system where the carbon intensity of baseload units (say hydro and nuclear) is far different than that of the higher cost generation resources that are more often on the operating margin (e.g., oil and gas units). For such reason, Ellis and Bosi (1999) concluded that this approach would not provide a particularly credible baseline.[10] It is not recommended for use, except as a component of other methods, discussed below.

Table 4 shows the data required for this method, and the recommended data sources. Data are typically available at three levels: (A) individual power plants; (B) fuel/technology type (natural gas/steam turbine, natural gas/combustion turbine, etc.); or (C) fuel type (coal, oil, gas, hydro, etc.). Level A data are most accurate, and level B data are second. Level A generation and fuel consumption data are available in many countries, generally from electric utilities. Level C, or aggregate generation and consumption data by fuel are available from the IEA, and can be used where local data are unavailable. (IEA data, however, are only available at the national level, and would not be helpful for sub-national grid areas.)

2.5.2. Generation-weighted average emissions rate, excluding must run/low running cost facilities

By excluding baseload resources that are least likely to be on the operating margin and thus displaced by a new project, this approach partly addresses the inaccuracy problem with the average method described in Section 2.5.1. A system average can be constructed that excludes facilities that are both must-run and low running-cost resources, such as hydro, geothermal, wind, low-cost biomass,[11] and solar. It is *prima facie* unlikely in most systems[12] that these resources would operate less in response to new generation from a CDM project. The choice to exclude only renewables is based on the fact that they have no associated fuel costs.[13]

[9] Circumstances under which the operating margin might shift significantly (e.g. ±10%) include: unusually wet or dry years on a largely hydro system, very small power systems, or dramatic shifts in relative fossil fuel prices. Steps can be taken to limit investor exposure to weather fluctuations (e.g. by normalizing to average water years).

[10] In some competitive electricity markets, all generators compete on the basis of strategic bid prices, which may not reflect operating costs in the short-run. In such a context, the Alberta (Canada) Emissions Quantification Working group recommended using a straight system average approach.

[11] Examples of low cost biomass resources are bagasse (at sugar mills) and paper and pulp residues. While some residues have an opportunity cost (e.g. for use in paper, fiberboard, or other commodities), this is typically beyond the utility operator's decision framework. Examples of higher cost biomass resources would be dedicated crops, such as woody feedstocks, or residues that require costly transportation to power plant sites.

[12] The notable exception would be systems where these comprise a majority of the resource mix. According to the World Commission on Dams, 24 of 150 countries rely on hydropower for over 90% of their electricity. (http://www.dams.org/report/report_factsheet.htm) One simple option for addressing this concern is to exclude a fixed percentage of these resources (e.g. 50% of total generation) from the calculation, in order to reflect that the fact that in countries with more than this share, some hydroelectricity generation is likely to be avoided.

[13] Due to their low running costs, nuclear and coal plants usually run as baseload plants, though they may still be affected by CDM projects. The issue of which resources to exclude deserves further analysis.

Table 4
Data requirements associated with the "average" operating margin methods

Data required	Data sources (in suggested priority order)
Generation data for all plants in each grid area for a recent year ($kWh_{generated}$)[a]	National ministry
	Relevant electric utility or system operator
	International data (IEA—only available at level C, national level)
Specific fuel consumption, heat rate or efficiency (kJ_{fuel}/kWh), often reported as total fuel consumption by plant, which can be divided by generation	National ministry
	Relevant electric utility or system operator
	IEA data (for level C analysis only)
	International sources (e.g. see CERUPT's use of data from the World Bank/Oko Institute's Environmental Manual)
Fuel specific carbon content (gCO_2e/kJ)	National ministry
	Relevant electric utility or system operator
	Fuel suppliers
	IPCC National Inventory Guidelines
T&D loss factor ($kWh_{generated}/kWh_{delivered}$), calculated at the grid level	National ministry
	Relevant electric utility or system operator
	International data (IEA, only available at national level)

Note: Level A is given by individual plant; B by fule/technology type and C by fule type.
[a] Net plant generation, i.e. net of plant own use or parasitic losses as most typically reported, rather than gross, should be used.

The resulting baseline emission rate under this approach represents an average of all coal, oil, natural gas, and higher-cost biomass resources. It would be a mix of both baseload and peaking facilities, which is appropriate given that most projects will avoid a mix of both types. However, it would not give greater weight to the higher-running-cost plants (in each time period) that are more likely to be reduced in operation. Typically, these are the plants facing higher fuel and/or O&M costs, due to lower efficiencies, higher fuel costs, or higher O&M requirements, and are frequently older steam turbine plants that have relatively high carbon emission rates. This approach is embodied in the CERUPT methodology (CERUPT, 2001), and has been recommended for small projects in Mexico (ATPAE/USAID, 2002).

The data requirements for this method are identical to the previous method above, with the exception that no data is required for the low-cost and must-run facilities, although some additional information is needed to identify these facilities (e.g. low-cost biomass vs. high cost biomass).

2.5.3. Dispatch decrement analysis

Actual dispatch data gives hourly generation for every plant, revealing the precise mix of resources that are turned on and off across the year in response to increasing and decreasing loads. These data, as reflected in stacked-resource load curves, allow one to determine which plants decrease production as loads decline. Generally, several plants decrease production concurrently, because of transmission constraints, variation of fuel and operating costs by plant locations and time of year, and cycling considerations. It is important to exclude storage hydro and related storage resources, even though they sometimes appear to be on the margin as they fluctuate in production in response to changing loads. Hydro resources are unlikely to reduce overall kWh of production in response to a new CDM project, as this amounts to wasting free electricity "over the dam", but instead might simply shift the hours of power generation.

Dispatch analysis approaches have been used for several GHG mitigation projects, including the World Bank/AIJ/GEF ILUMEX lighting DSM project in Mexico, the PCF Chacabuquito (Chile) hydro project, and several NESCAUM pilot projects in the Northeastern US. A simplified load curve method was developed and applied to several Brazilian case study projects by researchers at LBNL and the University of Sao Paolo for the Brazil-Aspen Global Forum (Meyers et al., 2000). The method suggested here has been applied in Mexico, and overcomes some of the weaknesses of the simplified methods by capturing the avoided generation effects across multiple plants (Lazarus and Oven, 2002).

In sum, this method can offer a more accurate, empirically based operating margin than the two average methods discussed above. However, its application will be limited to those countries with utilities willing and able to share the required information.

This approach requires all of the data shown in Table 4 at the plant level (A), with the generation data provided by plant on an hourly (or periodic) basis.[14] Such data are usually kept by the central utility or system operator. They are rarely published, and in some instances are treated as confidential, but occasionally can be obtained by agreement.

A variant of the dispatch analysis approach involves calculating a time-varying marginal emissions rate (on an hourly basis, or by load categories such as peak, shoulder, and base periods) and applying it to the time-varying output of a CDM project. In theory, this approach provides greater accuracy for a project with a variable load profile in a system with variable marginal emissions rates. For example, it would be more accurate for peakload reducing projects where peakload generation is particularly carbon-intensive (e.g. diesels cycling on and off inefficiently). This method also demands more monitoring and verification effort, requiring project output to be tracked on an hourly or periodic basis, rather than simple annual accounting. The average methods above would yield similar results with less overall effort if the project output and the system's marginal emissions rate do not vary much over time.

2.5.4. Dispatch model simulation

A dispatch or "production cost" modelling approach may be the most sophisticated and accurate operating margin approach. A dispatch or production cost model simulates the complex operations of the electric system in response to a decrease in demand or an additional supply from a new project. One kWh of electricity savings may affect the operation (and efficiency) of several plants, some on the margin, some not. A dispatch model properly configured to represent storage hydro resources will also provide a better picture of the response of a hydro-based system. This method, however, may be considerably more labour-intensive and costly to implement. In addition, it can be non-transparent, and can require advanced technical capacities for effective review. External validation of the model and model inputs are important, since results can be highly sensitive to assumptions of parameters such as fuel prices.

Utilities that use dispatch models must develop a comprehensive data set that accounts for the various financial parameters, technical performance, and demand characteristics of their grid. No additional data will be needed to develop a baseline other than what is already assembled for the normal use of the dispatch model. But utilities rarely make publicly available their dispatch model with the entire set of data and assumptions.

The dispatch model can be run once a year to yield standardised baseline emission rates for one or more load profiles (e.g. for a plant that operates year-round as baseload generation and another that operates more heavily during peak periods).

Table 5 compares the operating margin methods against each other (rather than against the fundamentally different *build* margin methods discussed below), using the main baseline criteria discussed in the introduction. The shaded cells indicate what might be considered decisive criteria. The system average method is presently too inaccurate, especially in systems with large amounts of low-cost hydro resources to be considered widely applicable, a conclusion consistent with previous OECD/IEA reports (OECD/IEA, 2000). The dispatch data and modelling approaches might be usefully applied on a country-specific or grid-specific basis. (See Category III in Section 3.). However, both approaches present data and model constraints that will render them inapplicable (at least for the time being) in many countries.

Therefore, we recommend that for the purposes of developing widely applicable standardised baselines, the system average method excluding low cost/must-run resources be used, *if and where operating margin* approaches appear appropriate (see combined approaches below). Prima facie, it is difficult to determine whether this method will yield results that are significantly more or less conservative than the more sophisticated operating margin methods (dispatch analysis and modeling). In Mexico for instance, the result for the system average with exclusions (0.80 g CO_2/kWh) was within 2% of the dispatch analysis result for the main national grid (0.81 g CO_2/kWh). However, in one of the sub-national grids (Baja California North) the dispatch method yielded a baseline 70% higher (1.7 vs. 1.0 g CO_2/kWh). To have a better understanding of the implications of the various operating margin methods, more case study analysis would be needed (e.g. Bosi et al., 2002).

2.6. Build margin methods

The *build* margin approach opens up the difficult counterfactual question that the *operating* approach conveniently avoids. The *build* margin approach makes a "best guess" as to what type of electric facility would have otherwise been built (or built sooner) had the project not been implemented. Even in well-planned electric systems, it is very difficult to predict the timing and type of new plant additions (beyond those already well into construction). Furthermore, historical experience and current construction activity may not always be indicative of future additions. Especially in situations

[14] To apply this method, one must determine all plants that reduce generation moving from higher to lower load hours, excluding hydro, pumped storage, and other storage-capable technologies, then calculate hourly (or other period) weighted average emissions rate across entire year, and from this calculate hourly (or other period) marginal emissions rate. See Lazarus and Oven (2002) for an example of this method in practice.

Table 5
Comparison of operating margin methods

	System average	Average excluding low cost/must run facilities	Dispatch decrement analysis	Dispatch model simulation
Accuracy	*Low*	Improved	Higher, though can be difficult to determine true marginal resources in hydro-dominated systems	Depends on assumptions
Data Availability (Practicality)	High	High	*Limited. May be considered confidential*	*Limited model availability*
Cost-effectiveness	High	High	Perhaps for large peakload saving projects when using time-of-use approach	Potentially costly model runs feasible only if project and credit flow is very large
Wide applicability	High	High	Limited	Low
Transparency	High	High, though deciding what to exclude introduces judgement and potential bias	Medium to high, if calculations are clearly presented	Low, given the dependency of results on detailed and often poorly documented model parameters
Conservative (relative to dispatch methods)	No, especially in systems with a large proportion of old fossil fired plants. In systems with considerable low cost, low C may actually dissuade investment	Must be judged on grid-by-grid basis	N/a	N/a
Consistency	High	High (providing there are common definitions of what facilities to exclude)	High, providing data is adequate	High, providing models are well-calibrated to actual circumstances
Reproducibility	High	High	High if access to necessary data	Medium (only if access to the models)

Italics represent the critical drawbacks of specific methods.

where new fuel infrastructures are developing or new technologies are emerging (as has been the case with natural gas and combined cycle technologies in several parts of the world, for example), the types of new capacity can vary significantly from year to year.

At the same time, it is a difficult question that must be addressed. There are good reasons to suggest that most CDM projects, small as well as large, will ultimately affect the schedule of new plant additions, and that the net emissions impact of delaying a series of plants can resemble displacing a combination of them. The question then boils down to making a reasonable estimate of what types of plants these will be, given available data, knowledge, and the need for transparency.

2.6.1. *Average of recent capacity additions*

This method involves collecting data on the most recent (and ongoing) construction activity and deriving a weighted average emissions rate based on an appropriate cross-section or ''cohort'' of facilities. While this method has been largely applied to individual GHG mitigation projects in case study contexts, this approach has been subject to extensive analysis and discussion in the literature as the basis for standardised multi-project baselines (Sathaye et al., 2001; USDOE/SAIC, 2001; OECD/IEA, 2000; Lazarus et al., 1999, 2000). It is also an input to the CERUPT standardised methodology for small-scale projects. Among the key dimensions that have been analysed in the determination of build margin baselines are:

Cohort: Which plant additions should be used to calculate the baseline and should they be derived from historical data or projections? Arguably the appropriate cohort is for the time period when a given project would be most likely to affect new construction, i.e., in the years after a project's on-line date. Expansion plans and forecasts can be used to estimate future additions, and have been applied to baseline calculations (e.g. ATPAE/USAID, 2002). However, plans are subject to major uncertainties, and there are often significant discrepancies among different forecasts (OECD/IEA, 2000). Furthermore, projections and plans lack transparency as they are often founded on models or judgement. As a result much of the build margin analysis has focused on the use of historical capacity additions—and new plants approved or under construction—rather than on plans or projections. (see OECD/IEA, 2000; Lazarus et al., 1999) Several approaches have been used to define an historical cohort, typically based on plants built within a specified number of recent years (e.g. 5 or 10). However, the pace of new construction varies widely among countries. In South Africa, for instance, only one plant has been constructed in the past 7 years (Winkler et al., 2000). In many Eastern European countries (i.e. potential JI host countries), the number of new plants in recent years is also very low, given the slump in electricity demand. Therefore, we recommend that cohorts be constructed from the most recent 20%, or most recent 5 plants, whichever is greater. In countries where supply capacity has been growing 4% annually—a reasonable rate for a developing economy—the 20% threshold is equivalent to the past 5–6 years of growth. We also recommend including plants that have initiated construction (e.g. beyond about 10% total plant expenditures), to make the cohort as up-to-date as possible.

Aggregation: Should different fuel types, technologies, or duty cycles (i.e. peak vs. baseload) be considered separately? While baselines based on fuel types or technologies do provide an incentive for higher-efficiency projects within a given fuel, they fail to account for the option of switching between fuels. These baselines can raise concerns about environmental effectiveness; and they could, if widely applied, encourage construction of efficient coal plants where other lower carbon fuels may be otherwise competitive (OECD/IEA, 2000). We do not recommend here that fuel-specific baselines be adopted as a general standard method, given their limited applicability and environmental integrity concerns. However, they may be useful where detailed baseline studies show that a less-efficient same-fuel technology is being displaced. Distinguishing baselines based on whether a plant is baseload, peakload, or intermediate, presents other challenges. It can be very difficult to categorize many power plants (e.g. single-cycle turbines), which can be operated in any mode, often varying from season-to-season or year-to-year based on supply constraints. Data is also often difficult to find. Furthermore, it is unclear whether enough CDM projects (other than possibly some DSM) could be classified as "peakload" to warrant separate baselines.

Stringency: Should the baseline reflect average or better-than-average performance relative to the identified cohort? For instance, the baseline can be set to reflect only the top 25% of the plants in a cohort, in order to promote conservatism. Such "stringent" baselines have been examined in much of the literature. Better-than-average baselines have been suggested as a means to reduce the potential for non-additional projects to gain credit, in part because of the notion that "truly" additional (or generally desirable) projects are more likely to have lower emission rates. While this approach has particular merit in the context of fuel-specific baselines, where the intent is to raise the bar to encourage the highest-efficiency of gas, oil, or coal plants, it becomes problematic when the full system cohort includes many different fuel types with widely varying carbon intensities. The South Africa case study in Sathaye et al (2001) illustrates how different percentile choices (10th, 25th, etc.) can yield dramatically different baseline emission rates. Therefore, we recommend that instead of relying on stringency to avoid awarding non-additional credits, more thorough additionality testing or analysis be applied to those project types where the risk of significant non-additional credits is highest. Also, the build margin using the recommended cohort (above) already includes, by definition, plants on the *margin* (as opposed to the *average* of all installed plants).

Data: Data requirements for this approach can be a challenge. First, the online dates and capacity (MW) values for recent additions are needed. These can often be obtained from national ministries or electric utilities. If not, the Utility Data Institute's World Power Plant Data Base—used in studies by OECD/IEA (2000) and others—does provide an adequate listing.[15] For the plants identified, all of the data items shown in Table 4 (generation, fuel consumption, and fuel carbon content) are needed. Plant (A) level data on fuel consumption or efficiency, however, are often hard to obtain, and generation (or load factor) data for newly added plants is often unavailable or unreliable, since it can take many months before a plant reaches its full operating capability. If unavailable locally, efficiencies and load factors can be reasonably estimated based on international parameters. For instance, the World Bank/Oko Institute's Environmental Manual[16] contains a database of technology and fuel-specific efficiencies and load factors that can be mapped onto plants for which no local data are available. These data tend to be rather conservative, since often plants perform at lower efficiencies and high carbon intensities in practice (e.g. due to frequent cycling or operation at less than full capacity).

Algorithm: Calculate generation-weighted average emissions rates for the cohort of plants identified.[17]

[15] UDI data are subject to some acknowledged gaps (incomplete listing of plants in some countries) that should be taken into account should this source be used to implement this method.

[16] See http://www.worldbank.org/html/fpd/em/model/em_model.htm and http://www.oeko.de/service/em/.

[17] If generation data are unavailable, generation-weighting can be done using default capacity factors by plant type.

Updating/dynamics: The emissions rate should be calculated for the year in question (online date of the project *or, if necessary, the timing of the baseline study*). The method should then be applied again 7 years later, with cohort comprising all additions during that intervening period (years 1–7 of the project)[18].

2.6.2. Single, proxy plant type

This method is largely recommended as an alternative where data sufficient for the recent capacity additions method are unavailable or otherwise inappropriate. The data will be inappropriate in sectors that are undergoing major changes that render past plant additions largely unrepresentative of new construction. Given its current ubiquity as the resource/technology of choice, natural gas combined cycle technology can be used as a default proxy until market conditions change, unless a country/ region has limited access to gas and/ or has generating options that are clearly less costly. The choice of proxy plant can also be determined on a region-specific level as the lowest cost resource.

A weakness of the recent additions approach is that historical data are typically 5–10 years outdated compared to the capacity additions that a CDM project actually delays or displaces (e.g. assuming a 4–7 year historical cohort, and 1–3 year before a project's impacts are felt on the schedule of new construction). This can be partly corrected if the historical build margin baseline emission rate is revised at year 8 of operation, the year in which baseline must be reviewed for CDM projects opting for the 7 year with 2 renewals crediting lifetime.

Another weakness is the potential year-to-year volatility of build margin approaches based on historical data. For instance, the cohort may contain one large hydro plant that accounts for much of the 20% most recent additions in a grid area. Once other new plants are built, this plant will drop out of the cohort and the resulting average carbon intensity might rise rapidly and significantly.

Despite these weaknesses, alternative methods do not present better options. Use of projections or planning models[19] introduces the potential for inconsistency (among forecasting approaches), non-transparency, and gaming (OECD/IEA, 2000). Simple proxy plant methods may be overly conservative in some cases (e.g. where a natural gas combined cycle baseline is used, and coal plants are also a realistic possibility) and inadequately, and fail to adequately reflect local conditions. Therefore, despite its weaknesses, the system-wide recent additions approach provides the best build margin method.

2.7. Combined margin approach

Since most projects will have some effect on both the *operating* margin, especially in the short term, and the *build margin*, especially in the longer term, methods that combine both effects will, in principle, provide a more appropriate baseline. We recommend here a relatively simple *combined* margin approach that draws from elements of the operating margin and build margin approaches described above. More sophisticated approaches are also possible, but do not necessarily provide greater accuracy for the additional effort and cost (see comment in footnote 19).

For most electricity projects, we recommend combining the *operating* and *build* margin methods identified above as most suitable for broad baseline standardisation for the first 7–10 years of a project. For example, in the case of CDM projects eligible for two baseline crediting lifetime options, the following baseline calculation are recommended:

For years 1–7 (projects choosing a 7-year crediting lifetime with the option of renewal) or years 1–10 (projects choosing one 10-year crediting lifetime, without renewal), with year 1 being the first year of project operations: Use the straight average of the emissions rates of the operating margin and build margin calculated as of year 1. The *operating* margin is based on the system average excluding low-cost/must-run resources, unless detailed dispatch data or models allow a more sophisticated approach. The *build* margin is based on historical data for the generation-weighted average of the most recent 20% of plant additions, or if data are inadequate using the proxy plant method.[20]

$$Combined\_margin_{1st\ \ crediting\ \ period} = \frac{OM_{year\ \ 1} + BM_{historical}}{2}.$$

For years 8–14 (for projects choosing 7×3 year crediting lifetime), the baseline is the build margin recalculated in year 8 to represent the average of new plant additions during the first 7 years of project operation ($BM_{\mathrm{years}1-7}$). And the same baseline

[18] The method could, in theory, also be revised more frequently with more recent plant data, but the benefit of such a decision would need to weighed against the additional data updating costs.

[19] For example, electric sector models that can simulate both the construction of new capacity and system dispatch can be run with and without the project in question to deduce a baseline from both build margin and operating margin projections. For instance, in the US, such models have been applied to develop standardised regional baseline emission rates across planning regions (Cadmus Group, 1998). Such models lead to an accurate electricity baseline emission rate to the extent that their projections of future behaviour are accurate. Model use is labour intensive and costly, and development, maintenance, and external verification of the model is an expensive proposition. Model results may be highly sensitive to key assumptions, and this sensitivity may not be particularly transparent.

[20] OM stands for Operating Margin; BM stands for Build Margin.

calculation would be done in year 15.

$$Combined\_margin_{2nd\ \ crediting\ \ period} = BM_{years\ \ 1-7},$$

$$Combined\_margin_{3rd\ \ crediting\ \ period} = BM_{years\ \ 8-14}.$$

This method seeks to reflect the typical displacement effects of projects. In essence, by averaging both a *build* and *operating* margin across the first 7 years, the *operating* margin could be considered to apply for the first 3.5 years after the project commences, while the *build* margin kicks in at year 3.5, a reasonable lag time reflective of planning, construction, and permitting period for new power plants. Since the project will truly be affecting the capacity actually built during this period (through the delay effect), at year 8 the baseline is updated to reflect actual construction during the prior period. While this will present some uncertainty, it should be noted that investors would receive a fixed baseline for the first 7 years, and can anticipate year 8 changes by observing the evolution of the power market.[21]

2.8. Special cases: Brownfield, off-grid projects and projects with specific alternatives

2.8.1. Brownfield projects

Efficiency enhancements and fuel switching at existing facilities are a potentially large source of GHG mitigation projects in the electricity sector, and an important category to consider separately given its particular features. It is useful to think of a brownfield project as two separate projects: one that "replaces" the electricity that would have been generated by original plant (using its original fuel), and another that increases electricity generation by making the plant more economical to operate. A brownfield retrofit or fuel switch could increase generation by increasing power plant capacity (e.g. repowering or generator replacement), by lowering operating costs (e.g. cheaper fuels, improved management, or more efficient boiler), or by extending the operating lifetime.

Therefore, the operating characteristics of the pre-retrofit plant provides an appropriate baseline to the extent: (a) that generation does not exceed pre-retrofit levels and (b) that the plant is likely to continue operating as it has in the past. The second condition requires close examination. Often, plants that are good candidates for efficiency upgrades or fuel switching are those with the least attractive operating characteristics in a power system, i.e. ones using high-cost fuels or inefficient combustion equipment. There may be a significant chance that in the absence of the investment, the plant would be upgraded in a manner that affects its output and carbon intensity within the project's crediting lifetime, or on the other hand decline or cease operations entirely. Therefore, we recommend that most retrofit projects be subject to more thorough analysis to better assess additionality.

To the extent that electricity production does increase as a result of the project, this added generation should be treated as other capacity addition, and use the same *combined margin* baselines described above for other projects.

2.8.2. Off-grid projects

Off-grid projects could be large in number, but due to the small amounts of electricity involved, they are unlikely to generate a significant fraction of total credits generated. For this reason, it is critical that the costs of baseline determination for this project category be kept low. Several studies have been conducted to shed light on the energy sources typically displaced by solar photovoltaic (PV) home systems and other off-grid project types, as summarised by Martens et al. (2001a). Martens et al. (2001b) look at baselines for various possible off-grid renewable projects. Using these studies, the Dutch CERUPT program has established a thorough set of baseline algorithms assuming displacement of kerosene, diesel generation, and diesel-based battery charging as relevant for several different project types, such as solar home systems, mini-hydro systems, wind-powered battery charging stations, and mini-grids.

Since it is difficult to obtain detailed data to assess the specific context of off-grid projects (especially smaller ones) in great detail, this paper does not provide original baseline recommendations for off-grid projects. However, the comprehensive Dutch effort (CERUPT, 2001; Martens et al., 2001b) provides an excellent starting point for off-grid projects. The authors therefore suggest that the CERUPT baseline guidance for off-grid projects be adopted, until further studies are done to refine these figures (CERUPT, 2001).

2.8.3. Projects with specific alternative

These projects are typically in category III (i.e. larger projects not eligible to the CDM "simplified procedures and modalities" for small-scale projects) and can clearly demonstrate that a specific type of plant is the most likely alternative for the non-project case. In these cases, *minimum performance parameters* (e.g. efficiency and load factors) should be developed for the baseline calculation to ensure that the baseline scenario facilities are based on reasonable assumptions. For example, rather than calculating the baseline based on the characteristics of a very inefficient gas plant, *minimum performance parameters* could be based on an average from the most recently built gas plants (OECD/IEA, 2000).

[21] The proposed method resembles in part the standardised methodology for small-scale renewable and efficiency projects recently adopted by the CERUPT program (Ministry of Housing, Spatial Development, and the Environment of the Netherlands, 2001, Volume 2c). The notion of a two-part operating, then build margin approach has also been considered by the Oregon Climate Trust and a PCF project in Costa Rica.

3. A decision framework for electricity projects

Section 3 embeds the standardised baseline methods described in the preceding discussion into a decision framework that can be applied to all electricity projects. It first discusses how additionality and baseline methodologies can and should be tailored to the scale and environmental risk of various project types. It proposes a three-category framework, and describes the specific baseline and additionality methods specific to each category.

3.1. Distinguishing among projects based on scale and environmental risk

No single baseline methodology can suit all the potential diversity of CDM projects in the electricity sector. These projects span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. This diversity calls for a range of baseline approaches.

In the preceding discussion, we suggested different standardised baseline approaches for grid and off-grid applications, and new vs. retrofit projects, as well as noting some more sophisticated standardisation options (e.g. dispatch-based operating margin methods) that can be applied where data and resources allow. The natural next question is which projects should be automatically eligible to use these standardised baselines, and which should be required to undertake more thorough baseline analysis to confirm additionality. The answer to this question lies in two key factors: *environmental risk*, the potential for significant crediting in excess of actual emission reductions, and *project scale*, an indicator of a project's ability to absorb the added costs of more thorough baseline analysis. Indeed, these two factors were among the rationale for the COP in approving simplified modalities and procedures (fast-track) for small-scale CDM projects. Classifying projects into one of three categories of increasing complexity can help to balance the objectives of low transaction costs and environmental accuracy.

A GHG mitigation project presents two related *risks to environment integrity*:[22] the project might have been implemented regardless of the specific GHG incentive (i.e. it is non-additional) or its baseline might be inordinately low (i.e. stringent) and therefore, no credits would accrue to a deserving project. According to Bernow et al. (2001), non-additionality may present the greatest risk, especially given the inherent difficulty of assessing investor incentives and behaviour. One can identify project types that are a priori more likely to be additional, such as fuel cells, windfarms, or high-efficiency motor programs, because of the lack of demonstrated market presence compared with well-established technologies, such as conventional combustion turbine technologies or standard motors, or because of well-identified market constraints that limit their adoption. However, Bosi (2001) found that the risk to environmental integrity of presumed additionality for small-scale renewable projects may be acceptably small, primarily because the overall power generation share of these projects is very small. More thorough baseline and additionality methodologies can therefore be reserved for projects that present greater environmental risk, i.e. larger projects employing more conventional technologies. In these cases, it will be important to look more closely not only at project additionality, but also at the variety of plausible counterfactual activities or baseline scenarios.[23]

In terms of ability to cover up-front transaction costs for baseline analysis, **project scale** can be defined by the financial value of the CER revenue stream that a project is likely to earn. Larger scale projects can earn a greater volume of emission credits than small-scale projects. Investors will balance the returns (CER value) against the transaction costs and risks (of non-approval) in pursuing a CDM project. Investors will tend to avoid projects whose expected CER revenues do not significantly exceed transactions costs, or present large uncertainties in terms of likely baselines (another rationale for standardisation).

Investors face transaction costs at a number of stages in the project cycle, from the preparation of project documents to monitoring and verification once the project is approved. Arguably, a detailed baseline study can be among the more significant costs, and now that an incipient market for project-based activities has developed, there is some empirical evidence upon which

[22] The environmental integrity criterion can be paraphrased here. The CDM is intended to displace reductions in Annex-I countries with less costly reductions in non-Annex I countries. By doing so, the CDM is intended to lower the costs of compliance with Annex I targets. Approval of non-additional projects or use of systematically high baselines, however, will generate credits that are not backed by real reductions. Parties using these credits will exceed their target, *de facto* if not *de jure*, thereby weakening the effectiveness of the CDM as a market mechanism for achieving the environmental objectives of the Kyoto Protocol.

[23] If the plausible counterfactuals span a wide range of carbon intensities, then if the wrong counterfactual were selected a project could conceivably receive a baseline emissions rate that is highly inaccurate. If the plausible counterfactuals span a narrow range of carbon intensities, the project's baseline emissions rate could not be radically incorrect even if the wrong counterfactual were ultimately selected. For example, in an electric sector dominated by one fuel, the possible counterfactuals would span a relatively narrow range of carbon intensities (corresponding to technologies with a range of efficiencies), and the environmental risk associated with selecting the wrong baseline is limited. In contrast, a CDM project in an electric sector that has several different fuels, the risk associated with the wrong baseline—especially those based on one specific alternative project—is greater.

Table 6
Baseline study costs as a fraction of 7-year CER revenues for four hypothetical CDM projects (assuming CER value of \$3/t CO_2)

	100 kW village hydro mini-grid	10 MW windfarm	200 MW hydro	200 MW natural gas CC
Assumed capacity factor	50%	30%	50%	80%
Total generation (000 MWh)	3	184	6136	9818
Baseline emission rate (t $C0_2$/MWh)	0.6	0.6	0.6	0.6
Project emission rate (t $C0_2$/MWh)	0	0	0[a]	0.5
Credit rate (t $C0_2$/MWh)	0.6	0.6	0.6	0.1
CERs (million t $C0_2$)	0.002	0.110	3.68	0.98
CER price (\$/t CO_2)	\$3.00	\$3.00	\$3.00	\$3.00
Value of CERs (7 years)	\$5523	\$331,355	\$11,045,160	\$2,945,376
Baseline study cost (at \$30,000) as % of CER value	543%	9%	0.3%	1.0%

[a] As noted above, hydro plant construction can lead to significant methane emissions from the decay of submerged vegetation, however, estimation methods have not yet been well developed.

to estimate the costs of typical baseline studies. For projects that are not very complex, the PCF suggests that the cost of presenting a case for environmental additionality and preparing a project-specific baseline study (in accord with their fairly strict norms) is approximately US\$20,000; more complex projects might double this cost to \$40,000.[24] For the purposes of discussion, let us assume a typical cost of \$30,000 per detailed baseline study. These costs can then be compared to the anticipated revenues.

Table 6 presents sample calculations for four illustrative projects: (a) a village-scale 100 kW hydro mini-grid, (b) a 10 MW wind farm, (c) a 200 MW hydro facility, and (d) a 200 MW natural gas combined cycle power plant. Assuming a \$3/t CO_2 credit price (similar to current levels in the pre-CDM market), it shows the total revenue[25] that these projects would earn over their first seven years, based on some typical assumptions about capacity factor, and project emission rates, and a hypothetical baseline emission rate of 0.6 t CO_2/MWh[26].

As illustrated, the costs of a \$30,000 detailed baseline study would overwhelm the revenues to be gained by a 100 kW hydro mini-grid project, which stands to generate about \$5500 in years 1–7. In contrast, such baseline costs would represent 1% or less of revenues of either large (200 MW) project. The 10 MW wind farm would stand to spend nearly 10% of its expected 7-year revenues. Clearly, these calculations are sensitive to assumed credit price and baseline emission rates, but the general conclusions are that:

- The cost of a project-specific baseline study could easily overwhelm the value of the revenues of a small project. In addition to providing predictability, transparency and comparability standardised baseline methodologies are essential if smaller CDM projects are to be feasible (they are also important for larger projects). Indeed, for a number of small renewable energy project proposals submitted for consideration, the PCF has noted that "project-specific baseline methodologies would be prohibitively expensive" (PCF, 2000a), and the COP has embodied this rationale in its decision on simplified procedure and modalities for small-scale CDM project activities.
- The cost of a project-specific baseline study will likely be a small fraction of the value of the revenues of a large project. If a more thorough baseline analysis adds rigour (i.e. limits gaming risks) and reduces environmental risk, then more detailed baseline study would appear warranted.
- For projects in the range of 10 MW (for zero-carbon resources) or 15,000 t CO_2/year, baseline study costs represent a non-trivial investment. Simplified methods that reduce environmental risk while avoiding the costs of full baseline analysis, e.g. by introducing simple additionality tests, would be attractive.

3.2. Matching project types and baseline/additionality methods

Based on their relative scale and environmental risk, CDM projects can be classified into three categories of baseline methods:

[24] The Prototype Carbon Fund reports \$20,000 for projects that are not very complex (PCF, 2000a), based on 3–4 person-weeks for experts with an understanding of the methodology, and private correspondence with a project developers and consultants suggests a figure of \$40,000 for more complex projects. (These cost figures are lower than the estimated transaction costs surveyed in Bosi (2001).)

[25] These calculations are *undiscounted*. One would arrive at the same results (in terms of baseline cost as % of project cost) on a discounted basis, if one assumed that CER price were to increase at the rate of discount. This is not an unreasonable assumption given that some analysts project that the real CDM market could lead to prices of \$5/t CO_2 and above during the 2008–2012 period (Grubb, 2001; Varilek and Marenzi, 2001).

[26] Though illustrative only, 0.6 t CO_2/MWh is a plausible value for many countries. For example, it is very close to the value of the build margin (i.e. weighted average of all recent plants) baseline calculated for electricity projects in India in OECD/IEA (2000).

Table 7
Categories of GHG mitigation projects in the electric power sector

	Project scale	
	Too small to absorb much transaction cost	Large enough to absorb some transaction costs
Project environmental Risk		
Lower risk	Category I Fast-track[a] new renewables (FT1a) Fast-track off-grid projects (FT1b)	Category II Fast-track energy efficiency projects (FT2) Other projects, e.g. mid-sized renewables or other technologies (subject to further analysis and agreement)
Higher risk	Category II Other fast-track projects (FT3)	Category III All projects not included in I and II, e.g. large, new (NFT1), efficiency (NFT2), cogeneration (NFT3), and brownfield (NFT4) projects Projects qualifying for I or II, but claiming that the standardised baselines methodologies are inapplicable

[a] Fast-track refers to projects eligible to simplified modalities and procedures for small-scale CDM projects, as per the 2001 Marrakesh Accords.

Category I: offers the greatest degree of standardisation and lowest transaction costs to smaller projects that present less environmental risk. Category I projects are automatically eligible for the standardised combined margin baseline. Suggested Category I projects include fast-track renewable projects and off-grid projects (that can use default baseline emission factors), because of their limited ability to support transaction costs, their less conventional nature, and thus lower environmental risk.[27] Since additionality is not tested, project types eligible for Category I should be considered carefully. For instance, small-scale hydropower and biomass facilities might be more appropriately considered in Category II, since they can use mature technologies and are often cost-effective under current conditions.

Category II: adds an additionality test to the Category I methodology, and is appropriate for projects that present somewhat greater environmental risk due to their larger size *or* use of conventional technologies. Suggested Category II projects include fast-track energy efficiency and fossil generation projects. Though small in scale, the technologies used are likely to be fairly conventional, such as fluorescent lighting or reciprocating engines.

Category III: introduces more thorough, project-specific additionality and baseline scenario analysis (see below) for larger projects that either pose more environmental risk or opt out of Categories I and II approaches. This category is recommended for all project types that do not qualify for the fast track treatment.

[27] Most, but not all, reviewers of an earlier draft of the report on which this paper is based found this proposed trade-off (i.e. no additionality test to help fast-track small low environmental risk projects get implemented) acceptable.

Table 7 summarises the recommended classification of project types into these three categories. This classification is very general, and leaves room for further adjustment, based on the assessment of individual technologies, project designs, and country contexts. For instance, it is worth examining whether larger (than fast track) advanced or unconventional technologies, which imply lower environmental risk, might be worth including in Category II. Similarly, fuel cells may be sufficiently unconventional (and higher cost) that they could be added to Category I for fast track and Category II for larger sized projects.

3.2.1. Additionality tests for Category II projects

As an inexpensive means to limit environmental risk, Category II projects would be subjected to an additionality screen or test. Since the focus of this paper is on baseline methodologies, specific additionality tests are not recommended, but options are reviewed.

Several additionality tests have been discussed in the literature, and included in submissions to the UNFCCC. A simple example of an additionality test is a penetration threshold. A technology would be deemed additional if it does not exceed a specified percent of electricity supply (USEPA, 2000). Low penetration can imply that a technology is not yet cost-effective in many situations, or faces difficult market or policy barriers. Penetration thresholds can be set at low levels and updated frequently to capture rapid institutional or technological advances. To simplify their application, and to reflect the fact that grid areas may be too small to capture the emergence of newly competitive technologies, penetration thresholds may be defined at a regional level instead of the grid areas recommended here for baseline development.

Another option is to define an additionality screen in terms of emissions rates. For example, an additionality threshold can be defined as a specified percentile (e.g. 10th) of power plant emissions rates within a grid area, and if desired by, fuel or technology type. Projects using technologies that surpass this threshold would be deemed additional by virtue of being more efficient (and presumably more technologically advanced) than most in the sector. Like penetration thresholds, such emission rate thresholds are a fairly coarse screen, making some fraction of business-as-usual (non-additional) eligible for CERs. In this case of a 10th percentile threshold, 10% of new generation sources would qualify.

Yet another option is to appeal to expert opinion and power sector surveys to define a pre-approved set of technologies that are deemed sufficiently advanced to automatically qualify as additional. This method is sometimes referred to as a technology matrix.[28]

3.2.2. *Baseline scenario analysis for Category III projects*

Because Category III requires a more rigorous assessment, the additionality of a project and its baseline emissions is determined through a process of scenario analysis, rather than being pre-determined as in Categories I and II. Scenario analysis is the predominant method used today for baselines. It involves considering a set of plausible, alternative scenarios for what would happen in the absence of a CDM project, and then using a well-defined and reproducible process to determine the most likely baseline. The overall methodology is well described in several other sources (ERUPT, 2001; CERUPT, 2001; UNIDO, 2001; various PCF documents; Lazarus and Kartha, 2001). Therefore, this section only touches on key elements.

Define candidate baselines: The candidate baselines identified for the scenario analysis should take into account other plausible options for meeting the same demand for electricity. Among these, the project developer should consider options such as the same project without emission credits (possibly with later implementation), and generation using other fuels and technologies that are already present in the electricity mix or likely to appear in the near future.

Determine most likely baseline: A variety of approaches can be used to cull the "most likely" from the plausible baseline options. No single method—regulatory and policy analysis, barrier and risk analysis, investment/economic analysis, or a conservatism criterion—is sufficient on its own to provide a robust baseline selection methodology.[29] Instead, these methods can be used together as needed, in systematic and, to the extent possible, simplified and standardised manner.[30] Three outcomes of a scenario analysis are possible:

(i) The most likely scenario is determined to be the project itself, i.e. it would have happened anyway. The project is thus non-additional and ineligible for credits.

(ii) The most likely scenario is determined to be ongoing expansion and operation of the overall grid, rather than any specific investment. This outcome could also arise if several new generation options are all plausible, and there is no compelling justification to deem one option the "most likely". In this case, it is recommended that the project adopt the same baseline emission rate (i.e. combined margin) as Category I and II projects. In such cases, the benefit of the Category III approach is a more rigorous assessment of project additionality.

(iii) The most likely scenario is determined to be a specific investment, facility, or activity. For example, the most likely baseline scenario for natural gas plant may be a coal plant at the same location. A specific alternative investment will most often be found for brownfield projects, such as retrofits or fuel switching, where continued operation of the existing facility provides an unambiguous facility-specific baseline scenario. In such cases, the baseline emissions rate can be quantified directly based on the presumed characteristics of the baseline investment or facility. The baseline emissions rate should be specified as a carbon intensity (e.g. t $CO_{2\ eq}$/MWh) rather than an absolute baseline (t CO_{2eq}), since the total MWh of electricity displaced (through efficiency or lower-carbon generation) will be unknown until the project is running and its output has been monitored, measured, and verified (OECD/IEA, 2000).[31] Since they may not be able to follow standardised rules, all assumptions and calculations should be presented clearly and transparently. M*inimum performance parameters* should be developed to ensure that baselines based on presumed specific fossil-based facilities use reasonable assumptions

[28] See SAIC/USDOE (2001) for an extensive discussion and case studies based on this option.

[29] See UNIDO (2001) for a comprehensive description of how these methods can be integrated.

[30] It is essential that in implementing this process the project proponents rigorously document information, assumption, and selection processes, so that a Designated Operational Entity can reproduce and thereby verify the project developer's choice of baseline.

[31] In certain situations, it is more accurate to express the baseline emissions rate in terms of efficiency (or heat rate, MWh/GJ of fuel). This may be the case in circumstances where the carbon intensity of the fuel supply (i.e., kg CO_2/GJ) can be expected to vary over time and this variation would occur in both the baseline scenario or project scenario.

(e.g. efficiency and load factors), as discussed earlier.

4. Conclusions

No single baseline methodology can suit all the potential diversity of GHG mitigation projects in the electric power sector. These projects span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. Furthermore, a range of considerations needs to be taken into account (e.g. accuracy and rigour, transparency, cost-effectiveness, and conservatism). This diversity calls for a range of baseline approaches, as well as additionality treatment. Although the focus of this study is on baselines, some suggestions are also made for the treatment of additionality.

Based on an assessment of the scale of projects (defined by the financial value of the emission credit revenue stream) and the potential risks to environment integrity, the different types of electricity projects are put in three categories (as shown in Table 7), each of

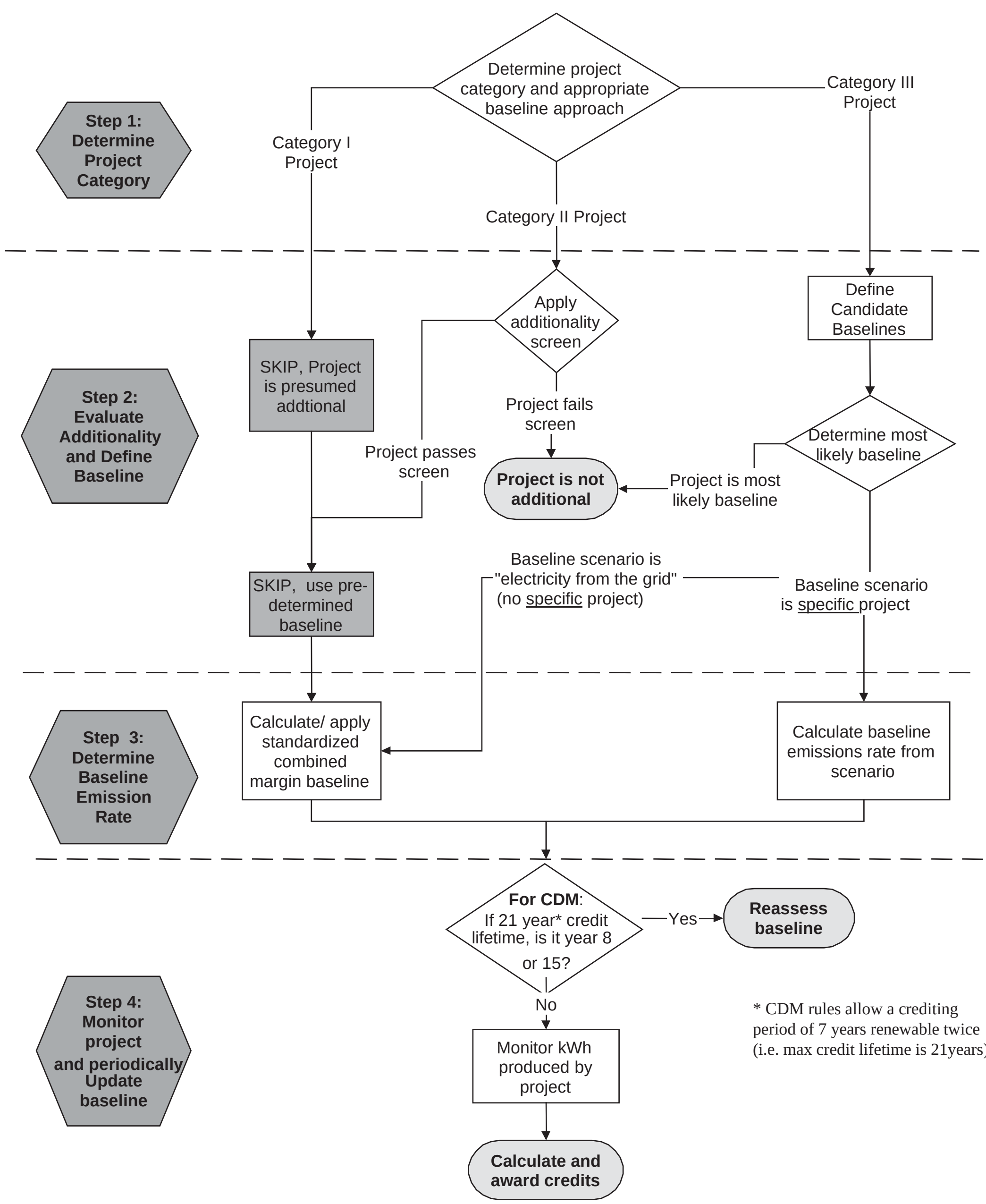


Fig. 1. Overview of recommended baseline methodology.

which has a corresponding baseline methodology and additionality treatment.

The recommended standardised baseline approach for most GHG mitigation electricity projects is a *combined margin* approach. This approach is considered appropriate to estimate avoided generation for in most cases, as it takes into account both: (i) the effect of a project on the operation of current or future power plants (this is referred to as the *operating margin*); and (ii) the effect of a project on the construction of other plants, either through delay or replacement (this is referred to as the *build margin*). It is assumed that most projects will have some effect on both the *operating* margin, especially in the short term, and on the *build* margin, especially in the longer term.

For brownfield (retrofit and fuel switch) projects, the emission rate of the existing facility may be a valid baseline (subject to more rigorous analysis) up to the amount of generation that the existing facility produces. For generation beyond this amount, the standardised *combined margin* baseline should apply.

It is critical to give standardized baselines to off-grid projects, such as solar home systems, hydro mini-grids, and biomass gasifiers, given the small amount of emission credits (and thus little capacity to absorb baseline transaction costs) and potentially large development benefits they are likely to produce, combined with low environmental risks. Given the comprehensiveness of the Dutch efforts in this regard, it is recommended that the Dutch CERUPT (2001) standardised baseline algorithms for off-grid projects be adopted, until further studies are done to refine these figures.

Other recommendations on baseline related issues include a recommendation that the default *geographic aggregation* level for standardised electricity baselines be the country level, allowing host countries to define sub-national grids or combine with other countries, if warranted by power system management practices and transmission availability. A practical and conservative recommendation for the *boundary* for power generation projects is to include direct on-site emissions (e.g. fuel combustion at the project site) only. Demand-side efficiency and distributed generation (and not the other electricity projects) should be credited with avoided T&D losses, using average grid area losses (excluding "non-technical losses"), or national average losses where grid-specific loss data are unavailable.

The methodology outlined above can be rendered as a step-by-step decision tree, as shown in Fig. 1. In Step 1, projects are placed into categories (I, II, or III). In Step 2, project additionality is evaluated and the baseline defined. Both Category I and II projects can use the pre-defined and standardised baseline methodology (combined margin) for most projects. Category II projects need to pass a simple additionality test. Category III projects must undergo a more thorough baseline scenario analysis. In Step 3, the standardised baseline emission rate can be calculated by each country once a year according to the combined margin method (calculated in t CO_2eq/MWh). This baseline emission rate is then applied to Category I projects (with the exception of off-grid projects), to Category II projects that are deemed additional, and Category III projects where the baseline is determined to be the general operation and expansion of electricity grid. Finally, in Step 4, the project is awarded credits based on its monitored generation or savings. For CDM projects choosing the 7-year-twice renewable crediting lifetime (i.e. an option for 21 years), the baseline will need to be reassessed (as described above) in years 8 and 15.

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