Understanding CDM Methodologies

A guidebook to CDM Rules and Procedures

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Introduction

The success of the Clean Development Mechanism (CDM) is a key feature of the Kyoto Protocol, engaging the private sector in mitigation and delivering substantial investment to developing countries. The CDM and the EU Emissions Trading Scheme are cornerstones of the global carbon market. Linking the two has been one of the most significant policy decisions undertaken in building that market. The UK is currently at the centre of the market, and UK approved project participants form a major proportion of the total CDM projects.

This is why I am delighted to support the publication of this guidebook to methodologies, which I hope will make some small contribution to increased transparency in the system. The process of project quantification is admittedly complicated and the detailed rules are not always fully understood. The robustness of these calculations is essential to confidence in the market.

The CDM Executive Board and the UNFCCC Secretariat has shown it is committed to the continuous improvement of the CDM, ensuring efficient and robust decision making. This guidebook is intended as a contribution to that improvement. The book was commissioned to help clarify the area and processes surrounding it, but it does not give the views of the UK government. The opinions expressed in this book are the authors' own and offer an independent guide to the implementation and interpretation of the CDM methodologies. It aims to provide a reference for practitioners, foster debate, and most of all help those not directly involved in the process to gain an understanding of the key principles involved in the CDM methodologies.

I hope this book can play a part in assisting host country governments and the private sector in countries currently not participating in the CDM to engage in the process and begin to implement projects in their own countries.

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1. Introduction

Climate Change is an important Problem

Climate change due to anthropogenic greenhouse gas emissions has become an issue of key political and economic importance. The scientific background has become quite clear, as shown by the summary for policymakers of the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report published in 2007. It states that "warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level" and that "most of the observed increase in globally averaged temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations".

Cornerstones of the Climate Policy Regime

The international climate policy regime has developed at a rapid pace during the last 15 years. The UN Framework Convention on Climate Change (UNFCCC) was agreed in 1992, the Kyoto Protocol followed and was finalized in 1997, and the Marrakech Accords negotiated in 2001 have set the cornerstones of the regime.

Distribution of Mitigation Effort

As greenhouse gas emissions are distributed across all economic sectors, their mitigation is a difficult task. So far mitigation technologies are costly and cannot address the whole range of emissions. To achieve stabilization of greenhouse gas concentration at a level which prevents dangerous climate change, an intense mitigation effort is required. Countries have very different levels of economic development and current as well as historical emissions and have argued that these differences should be taken into account to determine their participation in sharing the burden. The UNFCCC has thus defined the principle of common, but differentiated responsibility, where industrialized countries – that have been listed in Annex I – take the lead in mitigation. Non-Annex I countries provide reports on their greenhouse gas emissions.

Kyoto Protocol and Carbon Market Structure

The Kyoto Protocol has allocated emissions commitments to industrialized countries that are listed in the Protocol's Annex B[1]. These commitments have been specified in terms of greenhouse gas emissions budgets for the period 2008-2012. To reduce costs for the countries that took up commitments, a set of market mechanisms has been defined that are unprecedented in international economic policy. One of these mechanisms, International Emissions Trading (IET), allows governments of countries with commitments to sell unused shares of their emissions budgets to other countries. The second mechanism, Joint Implementation (JI), permits the generation of emissions credits through projects that reduce emissions. These credits can be used by the acquiring country to fulfil its Kyoto commitments; an equivalent amount has to be deducted from the emissions budget of the country hosting the projects. Finally, the Clean Development Mechanism (CDM) allows projects that reduce emissions in countries that do not have an emissions budget to generate emission credits that can be used by countries that have commitments. The CDM is the only instrument of the Kyoto Protocol that started before 2008; CDM credits (Certified Emission Reductions, CERs) can be generated from 2000 onwards.

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[1] Annex B differs from Annex I of the UNFCCC by the omission of Belarus and Turkey.

Institutional Set up of the CDM

A complex array of institutions has been set up since 2001 to guarantee the environmental integrity of the CDM. At the core, the CDM Executive Board (EB) decides about the technical rules for projects. Over time, the EB has created a number of supporting panels that provide technical expertise and prepare EB decisions. Within the last two years, a sizeable number of staff has been hired by the UNFCCC Secretariat to support the EB's work. Over time, the rules for formal acceptance of projects under the CDM have been elaborated by these institutions. This guidebook aims to explain the key elements of these rules and also provide an understanding about the decision making process of the CDM institutions.

Development of a multi-billion Euro Market

Many observers argued that the complicated CDM system would never work. However, since 2005, the CDM has witnessed a spectacular expansion as billions of Euros have been earmarked for the acquisition of CERs. Hundreds of projects have been formally registered as CDM projects and thousands of projects are under preparation. Project documents estimate a CER generation of several billion before the end of 2012. A whole new industry of project developers and other service providers has mushroomed creating the first carbon millionaires. Carbon market fairs draw thousands of participants. TV stations show features on the CDM at prime time. NGOs complain CERs lack environmental integrity, while industry associations argue for less stringent CDM rules.

Key Role of the Regulator to make CDM Credits credible

Never before has a market of this size been generated by pure government intervention. In contrast to other markets, the commodity traded on the CDM market does critically depend on the rulemaking of regulators. While a commodity market can be influenced by government intervention, the intrinsic characteristics of a commodity will not be affected by governments.

Will Surplus of Emissions Units in Countries in Transition be a Substitute for CDM Credits?

A market can only survive if a good is scarce. The surplus of the emissions budgets of Russia, Ukraine and Eastern Europe is larger than the shortfall of Western Europe, Japan and Canada. Therefore, there would not be a demand for CERs if the surplus would be sold in the market. However, institutional uncertainties in the countries with large surpluses, the possibility of early implementation of CDM projects and higher environmental credibility of CERs have enabled the CDM to take the lion's share of the international market. A key reason for that has been the EB's willingness to ensure that emission reductions are real, additional and credible through definition of rules for baseline determination and the additionality of projects. The EB thus acts like a guardian of the "currency" that the CERs embody.

Importance of CER Quantification Rules – Baselines and Additionality

The key principles of quantification of CERs have developed over time and are sometimes controversial. Not all available technologies that reduce emissions can generate CERs. Even if a technology has in principle been allowed to generate CERs, this does not mean that each implementation of such a technology in a developing country is able to claim CERs. Over the past three years the rules regarding CER generation have seen a substantial development and in some cases, sudden changes have had severe impacts on the attractiveness of certain project types.

Aim of Guidebook This guidebook will explain the principles and detailed rules underlying CER generation, as well as trace how they have changed. It will concentrate on key technologies[2] and where possible, examples will be used to illustrate rule application. Decisions have been assessed including the 34th meeting of the CDM Executive Board in September 2007.

[2] We for example do not cover afforestation and reforestation despite a wealth of rules that has been defined for these project types.

2. CDM principles and institutions

Sources of CDM Principles and Rules

The CDM is based on a huge body of rules. These rules have differing sources that define a de facto hierarchy. The highest level of rules is defined by international treaties that have been formally ratified by states, such as the Kyoto Protocol. The second level is an agreement by representatives of countries at a meeting of the international climate negotiation process, such as a COP decision. The third level is a decision of institutions created through an international treaty or the negotiation process, such as an EB decision. And on the lowest level, advisory bodies to an institution shape important parts of rules even if they formally do not decide on them – such as the Methodology Panel does with respect to proposed baseline methodologies.

Framework Decisions and Discretionary Decisions

Need for Hierarchy of Decisions

Depending on their hierarchical level, rules will have different characteristics and lifetimes. We differentiate them according to their stability over time into fixed "pillars" of the CDM regime which we call framework decisions and into discretionary decision making that often has a short lifetime. Up to now, there is no formal catalogue of decisions, nor a hierarchy of decisions which is a key weakness of the system and should be remedied to generate greater transparency and consistency of decision making.

2.1 CDM Framework

System of Russian Dolls

There is a clear hierarchy of pillars of the CDM that can be compared with a system of Russian dolls, with the UNFCCC being the outermost shell, the Kyoto Protocol the second layer and the Marrakech Accords the third.

The UNFCCC and the Kyoto Protocol

UNFCCC and Kyoto Protocol

The UNFCCC and its Kyoto Protocol are treaties that had to be ratified by countries and cannot be changed easily after ratification.

The UNFCCC is likely to remain the foundation of international climate policy for a very long time. Legally the provisions of the Kyoto Protocol could remain intact while only the first commitment period expires in 2012. However, it is likely that the post-2012 climate policy regime will be based on a new protocol. Further new protocols to the UNFCCC are likely to emerge over time as has been the case in the ozone regime.

COP/MOP Decisions

COP/MOP Decisions

Guidance and Interpretation of Framework through COP

As countries will not ratify treaties of thousands of pages, the pillars have gaps that need to be filled by detailed rules. Moreover, in some places ambiguous text is found that is due to the need to find a consensus in the negotiations without being able to agree on certain points. These ambiguities need interpretation. Thus, generally the pillars are not sufficient to implement CDM in practice. They define principles that have to be supplemented by further more detailed guidance, decisions on rule details and technical explanations. Such decisions will be taken by the annual Conference of the Parties to the UNFCCC and the Meeting of the Parties to the Kyoto Protocol, which are customarily held at the same time.

Special Status of the Marrakech Accords

The Marrakech Accords – a special form of COP/MOP Decisions

The Marrakech Accords are a group of decisions by COP 7 in 2001 and defined the details that could not be specified in the Kyoto Protocol[3]. So in theory they can be changed easily. However, there has been a tacit consensus that changing a part of them would destroy the carefully crafted equilibrium and jeopardize the implementation of the Kyoto Protocol. Nevertheless, some amendments have been made over time.

"Ordinary" COP decisions

During each COP, a decision on CDM issues will be made which is usually framed as "guidance" to the EB. This type of decision belongs to the discretionary decision making.

2.1.1 General CDM Principles

The UNFCCC

UNFCCC Principles regarding Market Mechanisms

As the term CDM was only defined in the Kyoto Protocol, the UNFCCC obviously does not contain CDM-specific rules. However, it contains a number of important principles that were preconditions for development of the CDM. The principle of common but differentiated responsibilities means that countries with a low degree of economic development and historical responsibility do not have to take up commitments, while those with a high development status and high responsibility do so[4]. However, all states participate in some action against climate change. While the UNFCCC did not introduce any legally binding emission commitments, it specified that industrialized countries (so-called Annex I countries) should take the lead in combating climate change and that they can implement commitments jointly[5]. This clause is the foundation stone of all market mechanisms in international climate policy.

The Kyoto Protocol

Annex I Commitments

The cornerstone of the Kyoto Protocol is the set of legally binding emission commitments for a group of 38 industrialized countries and countries in transition (so-called Annex B countries). These commitments relate to a basket of six types of greenhouse gases that are converted into CO_2 equivalents by using their Global Warming Potentials for a 100-year timeframe, as specified in the IPCC's 2nd Assessment Report of 1995. The commitments are to be reached in the commitment period 2008-2012 and quantified in comparison to a base year of 1990[6]. On this basis, an emissions budget is defined for the commitment period.

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[3] They were put in the form of a COP decision to be substituted by a decision of the first Conference of the Parties serving as a Meeting of the Parties to the Kyoto Protocol (COP/MOP) once the Kyoto Protocol had entered into force. As entry into force of the Kyoto Protocol took until 2005, the first COP/MOP was only held in December of that year in Montreal and rubber-stamped the decisions made in Marrakech, repeating them word by word. The references used here relate to the Annex of Montreal decision 3/CMP.1, which was derived from the Annex to Marrakech decision 17/CP.7

[4] UNFCCC, Art. 4,1

[5] Ibid., Art. 4,2 a

[6] Countries in transition were allowed to use a different base year; some countries chose the year or period in the late 1980s when their emissions reached their peak.

The Kyoto Mechanisms

To enable agreement on the commitments, an unprecedented array of market mechanisms, the so-called Kyoto Mechanisms, was introduced. While International Emissions Trading[7] allows the transfer of parts of the emissions budget between states, Joint Implementation[8] makes it possible for greenhouse gas reduction projects in countries with commitments to generate emission reduction units that can be sold to other states. The amount sold will then be deducted from the project host country's emissions budget.

The CDM Rules in the Kyoto Protocol

The CDM, also a project-based mechanism, is outlined in Article 12. It has two aims: to generate emission reduction credits for countries with commitments and to promote sustainable development in the project host countries[9]. CDM projects can only be implemented in countries without commitments[10] by private or public entities[11]. The emission reductions resulting from CDM projects have to be "real, measurable and long-term"[12]. As CERs cannot be offset by an equivalent reduction from the host country's emission budget, emissions reductions have to be "additional to any that would occur in the absence of the certified project activity"[13]. CERs can be generated from the year 2000 onwards[14].

CDM Principles in the Marrakech Accords

Small Scale Project Rules

The Marrakech Accords

The Marrakech accords establish basics principles of emissions assessment. Emissions reductions from CDM projects are derived from the comparison of baseline with project emissions adjusted for leackage. Baseline and project emissions are established in accordance with approved methodology which deals with issues of project boundaries, baseline emissions, emissions monitoring and adjustments for leakage.

The Marrakech accords also establish key eligibility rules and distinguish between large and small scale projects. **Nuclear power** is excluded from the CDM[15]. Regarding forestry, only **afforestation** and **reforestation** projects are allowed[16], whose rules were only decided by COP 9 in 2003[17]. **Small-scale projects** benefit from simplified rules[18]. Pre-defined baseline methodologies and a barrier test for additionality determination (see Chapter 3) can be used. Projects are allowed to use the same DOE for validation and verification. Moreover, the period within which a request for review can be raised is shortened to 4 weeks. The rule on the thresholds for small-scale projects is one of the few elements of the Marrakech Accords that was changed ex post (see Box 1)

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[7] Kyoto Protocol, Art. 17
[8] Ibid., Art. 6
[9] Ibid., Art. 12, 2
[10] Ibid., Art. 12, 3 (a)
[11] Ibid., Art. 12, 9
[12] Ibid., Art. 12, 5 (b)
[13] Ibid., Art. 12, 5 (c)
[14] Ibid., Art. 12,10
[15] Decision 17/CP.7, preamble which says that Annex B countries are "to refrain" from the use of nuclear power in the CDM. The text of 17/CP.7 was not repeated in decision 3/CMP.1 but only mentioned in its preamble.
[16] Decision 17/CP.7, para 7 (a)
[17] Decision 17/CP.7, para 11. Rules for forestry projects differ substantially from other project types but will not be discussed in this guidebook.
[18] Decision 17/CP.7, para 6 (c)

Small Scale Thresholds over Time

Box 1: Changes of definitions of small-scale project thresholds over time

The question of thresholds for definition maximum size thresholds for small scale CDM projects has led to repeated changes in the definition with huge impacts for project developers. Initially, the thresholds were 15 MW for renewable energy projects (type I), 15 GWh annual savings for energy efficiency projects (type II) and direct emissions of 15,000 t CO2 equivalent for other project types (type III)[19]. The threshold for type III projects immediately gave rise to a discussion[20] as the wording "both reduce anthropogenic emissions by sources and directly emit less than 15 kilotonnes" could be understood in two ways:

a) CER volumes as well as project emissions have to be below the threshold,

b) only project emissions have to be below the threshold.

COP 8 chose the second definition[21]. Unsurprisingly, many project developers submitted type III projects with substantial annual CER volumes[22], reaching up to several hundred thousand per year. Therefore, the EB reopened the discussion on small-scale thresholds in general[23]. Finally, COP 11 increased the threshold for type II projects to 60 GWh/year and applied interpretation a) to type III projects whose threshold was increased to 60,000 t CO_2/year[24].

Crediting Periods and Early Start Projects

CERs can only accrue from the date of registration of a CDM project for a **crediting period** of 10 years or for a period of three times 7 years with an update of the baseline after each interval[25]. For projects submitted for registration before 31 December 2005 that had started between 1 January 2000 and 12 November 2001, CERs would accrue from the starting date[26]. The deadline has subsequently been shifted several times (see Box 2).

Box 2: The snail's pace of early start projects

Establishment of the CDM institutions and approval of methodologies took more time than envisaged at Marrakech. When December 2005 approached, it became clear that many projects would not be able to submit a request for registration in time due to the lack of approved methodologies for many project types. Therefore, COP 11 expanded the definition of early start projects to those that had started by 18 November 2004 and submitted a new methodology or have requested validation by a designated operational entity by 31 December 2005 and extended the deadline to *registration* by 31 December 2006[27] As even this interpretation was immediately felt to be insufficient, the EB decided that "request of validation" was to be interpreted that a PDD had been submitted to a DOE by 31 December 2005 and that the methodology submission cut-off date was 11 January 2006[28]. Finally, COP 12 extended the deadline to 31 March 2007 and (incorrectly!) referred to decision 7/CMP.1 as relating to *submission* for registration, which obviously was equal to another extension…[29]

Quantification – Choosing Baselines and Additionality

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19 Decision 17/CP.7, para 6 (c)

20 See SSC_030

21 Decision 21/CP.8

22 Sources of greenhouse gases generated by the anaerobic decay or burning of manure, agricultural waste or other organic matter waste with biomass origin.

23 EB24 requested the SSC WG to develop new Type III categories, that include procedures for more precise estimations of emissions reductions and requested more details on monitoring by the SSC WG 07 meeting. Later, the EB agreed to allow a 25 kt CO2eq./yr limit on annual emissions reductions for all Type III categories as an interim measure.

24 Decision 1/CMP.2, para 28

25 Decision 3/CMP.1, para 49

26 Decision 17/CP.7, para 12. According to the CDM glossary, the starting date is the earliest date at which either the implementation or construction or real action of a project activity begins.

27 Decision 7/CMP.1, para 4

28 EB 23, para 90

29 Decision 1/CMP.2

Baseline Approaches

The Marrakech Accords define the basic idea of **baseline** determination, while they do not provide an operationalization of the additionality concept[30]. The concept of "baseline" is defined as "scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity"[31]. Baselines have to be project-specific[32] and defined in a way that CERs cannot be earned for decreases in activity levels outside the project activity or due to force majeure[33]. Relevant national policies and circumstances[34] and current practices in the host country or region[35] as well as least cost technology for the project type[36] are to be taken into account.

Three principal approaches are available for defining a baseline methodology:

- Existing actual or historical emissions, as applicable[37]
- Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment[38]
- The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category[39]

Section 4.1.1 describes how these approaches have been incorporated into baseline methodologies.

Project Boundary

Leakage

Principles for Baseline Determination and Monitoring:

The concept of **project boundary** encompasses "all anthropogenic emissions by sources of greenhouse gases under the control of the project participants that are significant and reasonably attributable to the CDM project"[40]. On this basis, **leakage** is defined as "net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project"[41]. Leakage shall be deducted from the emission reductions calculated against the baseline[42].

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30 Decision 3/CMP.1, para 43 just repeats the additionality principle of Article 12, 5 (c) of the Kyoto Protocol.
31 Decision 3/CMP.1, para 44. This is derived from the principle of "real…measurable…long-term" reductions in Article 12, 5 (b) of the Kyoto Protocol.
32 Decision 3/CMP.1, para 45 (c)
33 Decision 3/CMP.1, para 47
34 Decision 3/CMP.1, para 45 (e)
35 Appendix C to decision 3/CMP.1 "Terms of reference for establishing guidelines on baselines and monitoring methodologies", para (c) (i)
36 Ibid., para (c) (ii)
37 Decision 3/CMP.1, para 48 (a)
38 Decision 3/CMP.1, para 48 (b)
39 Decision 3/CMP.1, para 48 (c)
40 Decision 3/CMP.1, para 52
41 Decision 3/CMP.1, para 51
42 Decision 3/CMP.1, para 50

Transparency, Conservativeness, Consistency, Predictability, Rigour, Additionality, Accuracy, Completeness

Baselines have to be *transparent* and *conservative* and take into account uncertainty[43]. *Consistency*, *predictability*[44] and *rigour*[45] are necessary to ensure that emissions reductions are "real and measurable and an accurate reflection of what has occurred within the project boundary". Baseline methodologies have to address *additionality* determination[46] and shall "reasonably represent what would have occurred in the absence of a project activity"[47], if possible by an appropriate level of standardization[48]. **Monitoring** methodologies are to provide an "*accurate* measurement of actual reductions […] taking into account the need for consistency and cost effectiveness"[49]. Documentation of monitoring has to be *complete*[50]. Decision trees and other methodological tools are to be developed.

The CDM Institutions defined in the Kyoto Protocol: EB, DOEs

2.1.2 CDM institutions

Besides the principles, the ***institutional setting*** of the CDM is outlined in the Kyoto Protocol. Its rules are to be set by COP/MOP and it is to be "supervised" by the CDM Executive Board[51]. CDM projects are voluntary and to be approved by each country involved[52]. CERs are to be certified by independent auditors, the so-called Designated Operational Entities (DOEs)[53].

COP/MOP as Supervisor of EB in Marrakech Accords

The Marrakech Accords specify the competences of the different CDM institutions outlined in Article 12 of the Kyoto Protocol and define requirements they have to fulfil[54]:

COP/MOP has "authority" over the CDM[55]. It elects the CDM EB[56] and gives guidance to it. COP/MOP decides on the EB's rules of procedure[57] as well as acceptance of DOEs[58] and their suspension[59].

EB decides on Small-scale Rules, Baseline and Monitoring Methodologies and DOE Accreditation

The ***EB*** can make "recommendations" regarding CDM rules[60] and definitions of as well as simplified rules for small-scale projects[61]. It approves baseline and monitoring methodologies[62], accredits DOEs[63], does spot checks on their performance[64] and can suspend DOEs with immediate effect[65]. It maintains the CDM registry[66] for CERs, where each host country shall have at least one holding account for CERs[67]. Project participants can also have registry

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43 Decision 3/CMP.1, para 45 (b)
44 Appendix C to decision 3/CMP.1 "Terms of reference for establishing guidelines on baselines and monitoring methodologies", para (a) (ii)
45 Ibid., para (a) (iii)
46 Ibid., para (a) (v)
47 Ibid., para (b) (ii)
48 Ibid., para (b) (v)
49 Ibid., para (b) (iii)
50 Decision 3/CMP.1, para 62 (d)
51 Kyoto Protocol, Art. 12,4
52 Kyoto Protocol, Art. 12, 5 (a)
53 Kyoto Protocol, Art. 12,5
54 See Annex to decision 3/CMP.1
55 Annex to decision 3/CMP.1, para 3
56 Ibid, para 8 (a)
57 Ibid, para 3 (c)
58 Ibid, para 3 (a)
59 Ibid., para 21
60 Ibid., para 5 (a)
61 Ibid., para 5 (e)
62 Ibid., para 5 (e)
63 Ibid., para 5 (f)
64 Ibid., para 20 (e)
65 Ibid., para 21
66 Ibid., para 5 (l)
67 Appendix D to the Annex to decision 3/CMP.1, para 3 (b)

accounts[68]. The EB is "fully accountable" to COP/MOP, which means that it has to produce a report and a management plan[69].

The EB consists of 10 members[70] and an equal number of alternates [71], see Box 3; it has to be regionally representative[72].

Full Members and Alternates

Box 3: The changing role of alternates in the EB

While the Marrakech Accords did not envisage a role for alternates other than ensuring that members unable to attend a meeting could be replaced, EB rules of procedure allow alternates to act as de facto members[73]. They participate fully in all meetings and discussions, even if the members they are to represent are attending. As a term as alternate does not count towards the maximum time a member is allowed to serve on the EB. Over time, some persons have rotated between being a member and being alternates.

Decision Making and Voting

The EB can only decide if 2/3 of its members are present, including a majority of members from Annex I and Non-Annex I countries[74]. Decisions should be based on the consensus principle but can be taken by a ¾ majority if "all efforts at reaching a consensus have been exhausted"[75]. Voting is rare and avoided as far as possible.

Role of Committees and Panels

The EB can establish committees, panels or working groups but has to take into account regional balance of their membership[76], see Box 4. It has made extensive use of this possibility, setting up six panels and working groups[77] which are providing the bulk of technical work. Essentially the panels and working groups fulfil the same functions for the EB that the EB fulfils for the COP. Generally the EB has expanded the role of members – as chairs of panels and in conducting reviews. A contrasting approach would be to rely on the UNFCCC secretariat and ensure the EB is genuinely focused[78].

Tension between Expertise and Representation

Box 4: Impacts of the regional representation rule

The necessity to assign membership in the EB and its panels to represent all UN regions has led to the problem that expertise required for a specific panel may be scarce within certain regions. For example, the UNFCCC Secretariat had to repeat calls for selection of a member from the Eastern European and CIS region as there were no applications. This has also led to the necessity to expand panels to ensure a critical mass of expertise.

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68 Ibid., para 6 (c)
69 Annex to decision 3/CMP.1, para 5 (d)
70 Ibid., para 7
71 Ibid., para 9
72 Ibid., para 7
73 Decision 4/CMP.1, rules 29, 4
74 Annex to decision 3/CMP.1, para 14
75 Ibid., para 15
76 Ibid., para 18
77 Afforestation and Reforestation Working Group (ARWG), Accreditation Panel (AP), Accreditation Teams (AT), Methodology Panel (MP), Registration and Issuance Team (RIT) and the Small-Scale Working Group (SSC WG).
78 Decision 2/CMP.1, para 7 (e) asks the EB "to emphasize its executive and supervisory role by, inter alia, ensuring effective use of its support structure, including its panels, other outside expertise and the secretariat, and by strengthening the role of designated operational entities."

Role of DOEs – Absence of Accreditation, Validation and Verification Standards

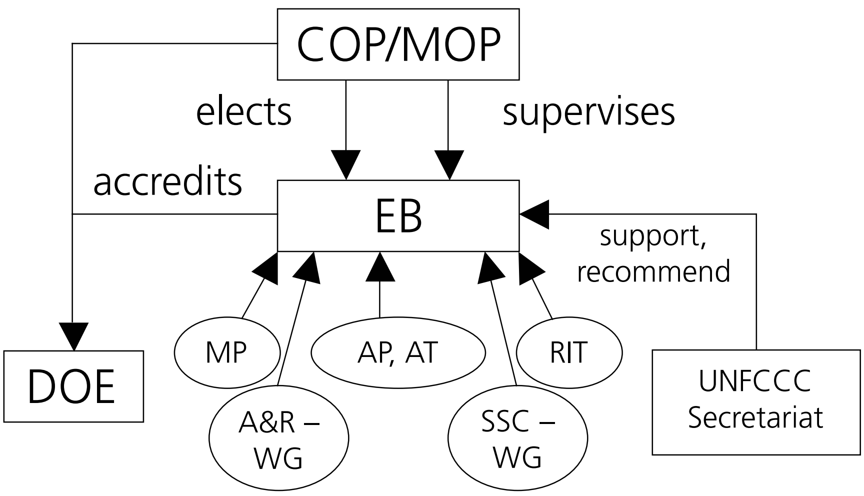
DOEs validate[79] proposed CDM projects and verify emission reductions[80]. They have to show that they are free of conflict of interest regarding the project participant[81]. To get accreditation as a DOE, companies or institutions have to fulfil a number of requirements listed in, including the need to have insurance cover[82], a management structure with quality assurance procedures[83] and documented structures which safeguard impartiality[84]. As project participants can freely select among accredited DOEs[85], an intense competition for getting validation and verification assignments has developed between DOEs. In addition, project participants not only select DOEs but contract and remunerate them for their services. Some have argued for a revision of this relationship because of a potential conflict of interest – where DOEs may have difficult rejecting validation of projects as they could lose clients whose projects did not achieve validation. There are no standards for validation and verification (see section 2.2.3). No liability other than the risk of losing the accreditation exists for mistakes in validation. DOEs are liable for "excess CERs" issued due to significant deficiencies in verification found in an EB-mandated review by another DOE[86]; however no DOE has been fined so far.

DNAs check Sustainable Development Impacts

Countries can only participate in the CDM if they have ratified the Kyoto Protocol[87]. Countries have to specify a ***Designated National Authority (DNA)*** for project approval[88]. Annex B countries can use CERs only if they fulfil the requirements of Article 5 and 7 of the Kyoto Protocol regarding their emission inventory and specification of their emissions budget[89].

Companies and public entities have to be authorized to participate in CDM projects[90]; this is usually done within the text of the approval letter by the DNA. They can only buy and sell CERs if the authorizing country is allowed to use CERs.

Figure 1: CDM institutions



[79] Annex to decision 3/CMP.1, para 27 (a)
[80] Ibid., para 27 (b)
[81] Ibid., para 27 (d)
[82] Appendix A to decision 3/CMP.1, para 1 (c)
[83] Ibid., para 1 (g)
[84] Ibid., para 2 (a) (i)
[85] Annex to decision 3/CMP.1, para 37
[86] Ibid., para 22
[87] Ibid., para 30 and 31 (a)
[88] Ibid., para 29. The preamble of 17/CP.7 had specified that sustainable development impacts of a proposed CDM project are only checked by the host country.
[89] Ibid., para 31. These requirements have been elaborated in decisions 12, 13, 15, 19, 20 and 21/CMP.1
[90] Ibid., para 33

Stakeholder Comments and Publication of Documents

The CDM is the ***most transparent*** international mechanism that currently exists. All rules[91] as well as all CDM project design documents of registered projects[92] are published by the EB. Documents received by DOEs from project participants for validation or verification purposes have to be published by the DOEs[93] except for information defined as confidential. Confidentiality cannot be invoked with respect to information related to baseline and additionality determination. Stakeholders can provide comments within the following periods from publication of the respective document on the UNFCCC website:

- 8 weeks for new methodologies[94]
- 30 days for PDDs[95], to be taken into account by the validator[96].

Moreover, a consultation with local stakeholders affected by the project is to be held and reported in the PDD[97], but the type of consultation process has not been specified[98].

Attendance of EB Meetings

EB meetings can be attended[99] by member countries of the Kyoto Protocol, accredited observers to the UNFCCC process and stakeholders[100] "except where otherwise decided by the EB". The latter phrase has been interpreted extensively by the EB, leading to closure of the meetings for about 50% of their time.

2.1.3 The CDM project cycle

The CDM principles and their supervision by the institutions have given rise to a sequence of procedures that every CDM projects has to complete before it gets CERs. This sequence is commonly called the CDM project cycle (see Figure 2).

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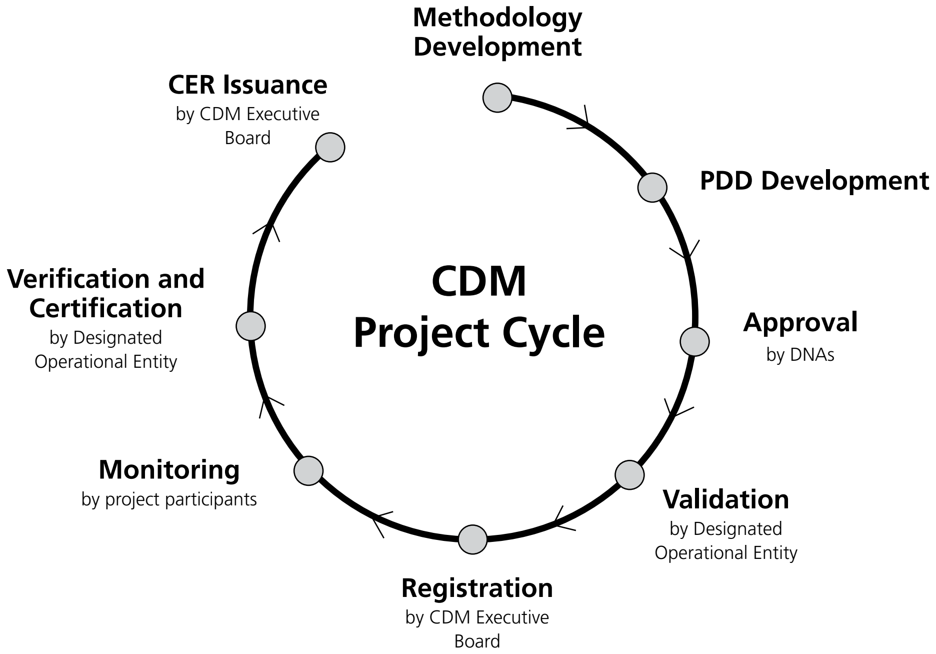
91 Ibid., para 5 (k)
92 Ibid., para 5 (m)
93 Ibid., para 27 (h)
94 Ibid., para 5 (j)
95 Ibid., para 40 (b), referring to "states, stakeholders and UNFCCC accredited non-governmental organizations". Some validators have thus not addressed comments submitted by non-UNFCCC-accredited NGOs from industrialized countries.
96 Ibid., para 40 (d)
97 Ibid., para 37 (b). Stakeholders are defined here as "public, including individuals, groups or communities affected, or likely to be affected, by the project" (para 1 (e)).
98 Project developers have invited stakeholder meetings, sent around questionnaires or used hearings required by the host country environmental impact assessment process.
99 Providing a webcast of the meetings that can be watched in a separate room has been interpreted as fulfilling this rule.
100 Annex to decision 3/CMP.1, para 16

Figure 2: The CDM project cycle



Need for approved Baseline and Monitoring Methodology, otherwise New Methodology Submission

The project cycle starts with the submission of a new baseline and monitoring methodology if no methodology approved by the EB exists for the project type[101]. These methodologies have to be developed by project participants[102]. A new methodology submission has always to be submitted together with a Project Design Document (PDD) describing the application of the methodology to a project[103]. As frequently new methodologies have been developed without having a sufficiently developed project, project developers have resorted to developing a PDD for a fictitious project ("dummy").

Revision of Existing Methodologies

Approved methodologies can be revised at any time but the revisions do not apply to projects that have been registered earlier as long as their crediting period is not renewed[104]. This means that several versions of a baseline methodology can be in use at the same time depending on the registration date of projects. Once approved, methodologies are a public good. This and the high risk of rejection has led to a reluctance of the private sector to develop methodologies as this can be very costly.

Validation of PDD by DOEs

Once a PDD has been written, it is submitted to a DOE for validation[105], which then published it for public comments The DOE checks whether the PDD fulfils the CDM requirements[106], especially with regards to eligibility of host country to participate[107], local stakeholder comments[108], analysis of environmental impacts[109], correct use of an approved baseline and monitoring methodology[110] and existence of an approval letter of all countries involved in the project[111]. A monitoring plan has to describe collection and archiving of all relevant data necessary to determine baseline

[101] Ibid., para 37 (e)
[102] Ibid., para 45 (a)
[103] Ibid.,para 38
[104] Ibid., para 39
[105] The key elements of a PDD are defined in Appendix B to decision 3/CMP.1
[106] Annex to decision 3/CMP.1, para 35
[107] Ibid., para 37 (a)
[108] Ibid., para 37 (b)
[109] Ibid., para 37 (c)
[110] Ibid., para 37 (e)
[111] Ibid., para 40 (a)

and project emissions as well as leakage[112]. It has to include quality assurance and control procedures[113]. If the monitoring plan is revised during the crediting period, it has to be revalidated by a DOE[114]. This rule has tacitly been reinterpreted (see Box 5)

> **Box 5:** Changes in monitoring plan after registration
>
> As practice has shown that the original monitoring plan can be applied only in a few cases, it has become common practice to have the monitoring plan simply changed as recommended by the verifying DOE.

Validated Monitoring Plans often amended on Verification

Registration and Request for Review

If the DOE thinks that the PDD conforms to the rules, it publishes a validation report which forms the basis of a request for registration[115]. The project is registered automatically within 8 weeks from the receipt of the registration request (4 weeks for small-scale projects)[116], unless at least three EB members launch a request for review[117]. If the EB reviews the project, it can be rejected or corrections to the PDD requested.

Verification and Certification of Emissions Reductions

Once the project is operational, project developers monitor the emissions reductions according to the approved monitoring plan. Verification and certification of the emission reductions achieved during a certain period is then done by a DOE[118] based on a monitoring report[119]. It has to include an on-site audit to review records, interview project participants and local stakeholders and test accuracy of monitoring equipment[120]. Recommendations have to be made to change monitoring for subsequent crediting periods[121]. A verification report has to be published[122] on which the quantity of emissions reductions achieved is to be certified[123].

CER Issuance

The certification report is the request for CER issuance[124]. Three or more EB members can launch a request of review of CER issuance within 15 days, on grounds of "fraud, malfeasance and incompetence" of the verifying DOE[125]. CDM projects have to pay an administration fee to the EB[126] and an adaptation fee of 2% of CERs in kind[127] from which projects in least developed countries are exempt[128]. After deduction of this fee, CERs can be transferred to the account of project participants[129]

[112] Ibid., para 53
[113] Ibid., para 53 (e)
[114] Ibid., para 57
[115] Ibid., para 40 (f)
[116] Ibid., para 36. The PDD and validation report are published on the UNFCCC website. However, sometimes these documents have been uploaded by the UNFCCC Secretariat only six weeks after receipt of the registration request, extending the time period for registration considerably.
[117] Ibid., para 41
[118] Ibid., para 61
[119] Ibid., para 62 (a)
[120] Ibid., para 62 (b)
[121] Ibid., para 62 (e)
[122] Ibid., para 62 (h)
[123] Ibid., para 63
[124] Ibid., para 64
[125] Ibid., para 65
[126] Formally called "share of proceeds" (see Art. 12, 8 of the Kyoto Protocol); Annex to decision 3/CMP.1, para 66 (a)). Regarding the fee level see section 2.2.4.
[127] Decision 17/CP.7, para 15 (a)
[128] Ibid., para 15 (b)
[129] Annex to decision 3/CMP.1, para 66 (b)

EB Decision Making and the Role of COP/MOP

2.2 COP/MOP Rules and Guidance and the CDM Executive Board's Decision Making Power and Discretion

On the basis of COP/MOP decisions the EB has developed detailed rules and guidance. Frequently, these have been subject to specific guidance of the COP/MOP. However, COP/MOP only meets once per year and has a full agenda covering all aspects of the climate policy regime. Therefore, it will not be able to take many decisions on CDM matters. The scarce time requires concentration on important issues, which will only be reopened by countries in very important cases. Generally, COP rubber-stamps technical items submitted by the EB such as the rules of procedure of the EB and small scale project rules[130] and rules for review of registration and issuance[131], all three confirmed by COP 11[132]. This shows a tendency that the COP/MOP is formally responsible for decisions but decisions are taken by the EB. Some COP/MOP decisions also take the form of lists of tasks for the EB[133].

Between the COPs the Board has a broad Decision Making Power and Discretion

The EB takes discretionary decisions in several formats. The largest share of decisions is reflected in the EB meeting reports and their annexes. Decisions that in the past were Appendices to the EB report have been put in the body of the report (e.g. reasons for reviews and rejections of projects). Moreover, there exist occasional documents entitled "guidance".

Generally the EB is reluctant to give extensive and detailed reasons for its decisions – and does not have a clear doctrine of precedent it is not strictly bound by previous decisions. There are different views within the board regarding the relative importance of predictability and certainty, over discretion and ability to rectify mistakes. Over time, the EB has changed the formats of decisions.

Panels set Basis for many EB Decisions

Changes and reinterpretation of rules have been most frequent where pillars are ambiguous or outright controversial. This is due to the interaction of interest groups with the institutions. Moreover, accumulation of practical experience generates new need for discretion, especially regarding baseline and monitoring methodologies).

Sometimes, EB does not follow Panels

On most issues consensus can be reached fairly fast and within the Panels and Working Groups, i.e. on lower tiers of institutions. In these cases, the EB rubber-stamps the panel/working group recommendations.

In a minority of issues, the EB does not agree to the recommendation of the Panels/Working Groups. Sometimes, they refer the issue back to the Panel, which had made the recommendation and sometimes the EB takes a decision without consulting the Panel again.

Controversial Issues referred to COP

On some controversial issues, the decision was referred to COP/MOP as the EB did not reach consensus and did not want to vote. Sometimes even COP/MOP was not able to take a decision and thus postponed the topic. Such currently stalled topics are the eligibility of carbon capture and sequestration, new capacity of HCFC-22 production and of projects reducing the use of non-renewable biomass in the CDM; between 2001 and 2003 it was the case for afforestation and reforestation.

Policies excluded but Programmes allowed

130 Decision 21/CP.8

131 Decision 18/CP.9

132 Decision 4/CMP.1. A unique exception is the definition of eligibility of land for afforestation and reforestation which had been decided by EB 22 and EB 26 and where COP/MOP 2 did not support these decisions (1/CMP.2, para 25).

133 See e.g. decision 1/CMP.2

2.2.1 Decisions on overarching political questions by COP

Some overarching non-technical questions, some of which are of key importance for the future of the CDM, have been decided by COP/MOP.

Programme Documentation Need

Policies and standards are not possible as CDM whereas projects can be coordinated under a **programme of activities (PoA)**[134], for which rules have been defined by the EB (see Box 6).

> **Box 6:** Rules for Programme of Activities[135]
>
> For registration of a PoA as a single CDM project activity and issuance of CERs, the coordinating/managing entity shall develop a Programme of Activities Design Document (CDM-POA-DD) setting a framework for the implementation of the PoA and clearly defining a CDM programme activity (CPA) under the PoA. The stakeholder consultation and environmental impact assessment can be done on the PoA level. In a second step, a PoA specific CDM Programme Activity Design Document (CDM-CPA-DD) needs to be developed that contains generic information relevant to all CPAs under the PoA. Subsequently, the standard procedures of the CDM project cycle will be applied. In contrast to standard CDM projects, CPAs are added to a PoA but are not registered by the CDM EB. Templates for POA-DD and CPA-DD were published in August 2007.

2.2.2 EB decisions on overarching political questions

EB Reluctance to address political Questions

The EB has avoided taking many key political decisions and which has not helped to reduce, and arguably has added to the confusion surrounding many issues. To name a few:

- How to deal with ODA/subsidies in the additionality assessment?
- How to deal with exports, e.g. grid exports?
- Can CERs be earned for projects satisfying suppressed demand?
- Is it possible to turn a project into a CDM project that is already operational? For a long-time this was unclear but today seems to be commonly accepted, without any formal decision being taken.

Unilateral Projects allowed

Nevertheless the Board has taken some decisions which are politically significant

Double Counting of Biofuels

A critical question, which had led to an intense controversy during the negotiations of the Marrakech Accords was solved by a simple EB decision – the acceptance of **unilateral** CDM, requiring approval by the DNA of the buyer country once the CERs are sold[136].

Another decision was made on **double counting**, allocating ownership rights to the consumers of biofuels[137]. This decision is however inconsistent with the practice in other sectors. For instance, no one would question allocation of ownership rights to the producers of renewable energy.

[134] Decision 7/CMP.1, para 20
[135] EB 32, Annex 38 and 39
[136] EB 18, para 57
[137] EB 26, Annex 12

While COP/MOP has provided that Large projects can be bundled without any limit[138], the board has placed a limit of bundling of small-scale projects to the overall small-scale threshold[139].

An official glossary defines key CDM terms; it has been regularly updated but never been subject to a COP/MOP decision.

2.2.3 Active COP/MOP guidance for the EB

Missing Validation and Verification Standards due to Existence of Validation and Verification Manual

Sometimes, COP asks the EB to work on regulatory issues that it feels insufficiently addressed.

COP 12 asked the EB to promote quality and consistency in verification and validation by DOEs by providing guidance to DOEs[140], as no rule of the Marrakech Accords provides validation and verification standards. In an attempt to make DOE operations comparable and consistent, Det Norske Veritas Certification (DNV) in cooperation with TÜV Süddeutschland and KPMG had developed a Validation and Verification Manual (VVM) in 2003. The VVM introduced the terms "Corrective Action Request" (CAR) and Clarification Request (CL). The former shows that the DOE deems the CDM rules be violated by the PDD, whereas the latter indicated that information is insufficient, unclear or not transparent enough to establish whether a requirement is met. Under the VVM, DOEs follow a validation protocol which contains a set of 86 questions. Despite substantial changes in the PDD and the EB practice, the VVM has not been revised so far. While most DOEs (DNV, TÜV Süd) use the template provided by the VVM to structure the validation report, others (SGS) have used their own structure. However, the EB was slow to address the task given by COP after deciding that the VVM should be reviewed and a revised version should be formally adopted after inputs by DOEs and the general public had been solicited[141]. Until COP 13, this issue had not been resolved.

Formal Adoption of revised VVM planned

2.2.4 Administrative decisions by EB vetted by COP/MOP

With regards to purely administrative decisions, COP/MOP essentially vets proposals made by the EB.

Administration Fee

The Marrakech Accords had specified that for financing of the EB and the regulatory structure, an administration fee could be levied. On suggestion of the EB, COP 11 accepted a fee of 0.1 $ per CER up to 15,000 CERs per year and 0.2 $ for CER volumes above this level. The fee is collected when CERs are issued[142]; at registration an advance payment calculated on the average annual issuance level forecast in the PDD is levied[143].

EB can ask for Corrections after Review

The EB felt that the Marrakech Accords were too constraining regarding the outcomes of a review of a registration or issuance request. Instead of only allowing acceptance or rejection as a result of a review, the EB can ask project developers to make corrections to the PDD[144]. The same

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138 Ibid., para 21
139 EB 21, Annex 21
140 Decision 1/CMP.2, para 12
141 EB 32, Annex 1
142 Decision 7/CMP.1, para 37. Previously, a staggered registration fee had been levied, ranging from 5000 to 30,000 $ depending on the size of the project (EB 6, Annex 5)
143 EB 23, Annex 35, which also specifies that the advance payment is capped at 0.35 million $ in the case of rejection, any fee above 30,000 $ will be paid back to the developer.
144 Annex II to decision 18/CP.9, para 18 (b)

changes were applied for a review of CER issuance. This decision has given the EB substantial discretion in evaluating projects. Since the setup of the Registration and Issuance Team (RIT) and with the increasing availability of UNFCCC staff, scrutiny of registration requests has increased substantially. The option to register or issue "with corrections" is now chosen frequently (see Tables 1 and 2 below) and corrections are even asked for if a request for review is not agreed by the EB.

Table 1: Rejections, corrections and requests for review and reviews of registration requests (by Sep. 28, 2007)

	2004	2005	2006	2007
Registrations (=100%)	1	62	408	329
Requests for review	2 (200%)	5 (8.1%)	73 (17.9%)	134 (40.7%)
Reviews	2 (200%)	4 (6.5%)	22 (5.4%)	59 (17.9%)
Corrections required*	–	1 (1.6%)	32 (7.8%)	59 (17.9%)
Rejections	–	–	10* (2.5%)	25 (7.6%)

* Includes registrations "as corrected"
** One further rejection was withdrawn in 2007

2.2.5 Administrative decisions taken only by EB

PDD Template

Increased Emphasis on Monitoring Sections

For development of the PDD, a template has been provided since August 2002. It has been revised twice, with considerable impacts on the presentation of emissions reduction and application of the baseline and monitoring methodology. The first version contained 6 generic sections on general project description, baseline methodology, choice of crediting period, monitoring methodology, calculation of greenhouse gas emissions, environmental impacts and stakeholder comments. In its second version of July 2004, the titles of the sections were changed and the section on monitoring expanded considerably to differentiate between data needed to determine the baseline and those that determine project emissions; an option for direct monitoring of emissions reduction was also included. Data for leakage calculation would feature in another subsection. A description of the management structure used for monitoring was now also required. The third version of July 2006 combines the baseline and monitoring methodology sections and eliminated the section on estimation of greenhouse gas emissions. This took into account the change in the methodology procedures where baseline and monitoring methodologies were now combined. Description of data sets is now differentiated into data available at validation and data sets that are monitored. Measurement methods have to be described for each data unit. The monitoring sections of the PDD have thus gained importance over time; they are the sections which are most likely to generate problems during validation.

Format of DNA Approval Letters

After initial problems with differing formats of DNA approval letters, the EB decided that an approval letter should contain the following statements: The country has ratified the Kyoto Protocol; the approval of voluntary participation in the proposed CDM project activity; and for host countries the statement that the proposed CDM project activity contributes to sustainable development[145].

[145] EB 16, Annex 6

Verification

Regarding verification, according to the CDM glossary, there is no prescribed length of the verification period. It shall, however, not be longer than the crediting period. The first monitoring report made publicly available by DOEs on the CDM website shall be the one prepared by the project participants prior to the verification[146]. If activity levels or non-activity parameters have not been monitored in accordance with the registered monitoring plan, the verifier shall make the most conservative assumption theoretically possible[147]. In case the verifier has requested corrections, the revised monitoring report shall be submitted as an additional document. If a verifier finds that there has been a deviation from "the provisions contained in the documentation related to the registered CDM project" it can either reject certification or lodge a request for deviation with the EB[148]. Verifiers shall ensure that all monitoring parameters required by the registered monitoring plan are reported by the project participants at the intervals required by the registered monitoring plan. These data should be contained in the monitoring report before a request for issuance is made, and submitted to the secretariat in a format which allows for assessment by the RIT member appointed to conduct the appraisal[149].

Shift of Start Date of Crediting Period

Start dates of crediting periods can be changed once after registration for up to one year into the past or future from the date indicated in the PDD, provided that the start date in the past is not earlier than the date of registration. A shift of more than 1 but less than 2 years into the future can be made if a confirmation from a DOE is submitted that no changes have occurred which would result in a less conservative baseline and that substantive progress has been made by the project participants to start the project activity. Moreover, a confirmation from the host country DNA is required that the revision to the crediting period will not alter the project's contribution to sustainable development[150]. This has led to the bizarre situation that a project with already issued CERs was able to change the start date of its crediting period afterwards[151].

CER Issuance

In contrast to registration, issuance practice has not changed substantially over time. Reviews are more infrequent and rarely have led to a reduction in CER issuance (see Table 2). Requests for permission to resubmit requests for issuance for previously rejected requests for issuance have to be lodged within 60 days from the date of rejection[152].

Table 2: Rejections, corrections and requests for review and reviews of issuance requests (by Sep. 28, 2007)

	2005	2006	2007
Issuances (=100%)	4	126	239
Requests for review	–	15 (11.9%)	41 (17.2%)
Reviews	–	6 (4.8%)	8 (3.3%)
Corrections required	–	3 (2.4%)	18 (7.5%)
Rejections	–	2 (1.6%)	–

146 EB 25, para 107
147 EB 26, para 109
148 EB 22, Annex 6
149 EB 26, para 109
150 EB 24, annex 31
151 EB 25, para 105
152 EB 31, para 86

3. Additionality rules determined by EB

3.1 Additionality tools

EB drives Additionality Rules

Regarding additionality determination, the EB has been driving the rules, as COP/MOP has never been able to agree on a technical definition of additionality with the exception of the rules for small-scale projects. While COP/MOP has repeatedly stressed that the additionality rules defined by the EB are not mandatory, it did not cancel the rules specified by the EB.

Barrier Test for Small-Scale Projects – Investment Barrier, Technological Barrier, Prevailing Practice Barrier

For small scale projects, additionality testing has been defined by EB 7 in January 2003[153]. Its aim is an explanation to show that the project activity would not have occurred anyway and enumerates four types of barriers used to prove additionality – investment barrier, technological barrier, barrier due to prevailing practice and other barriers. Investment barriers are defined as availability of a financially more viable alternative that would have led to higher emissions. The technological barrier requires existence of a less technologically advanced alternative that involves lower risks due to the performance uncertainty or low market share of the new technology adopted for the project activity and so would have led to higher emissions. The prevailing practice barrier says that prevailing practice or existing regulatory or policy requirements would have led to implementation of a technology with higher emissions. Other barriers include institutional barriers or limited information, managerial resources, organizational capacity, financial resources, or capacity to absorb new technologies Project participants have to demonstrate to a validator that the project activity would otherwise not be implemented due to the existence of one or more barriers listed. A short explanation of each barrier is provided.

Consolidated Additionality Tool

Subsequently, the EB decided that a baseline methodology has to demonstrate that a project activity is additional and therefore not the baseline scenario[154]. It added later that this could be done through a flow-chart, a series of questions, a qualitative/ quantitative assessment of different potential options describing why the non-project option is more likely, a qualitative/quantitative assessment of one or more barriers facing the proposed project and proof that the project type is not common practice in the proposed area of implementation, and not required by recent/pending legislation/regulations[155]. As these options were seen as too broad, a **consolidated additionality tool** was agreed as a general framework for additionality testing, but with a voluntary character[156]. It contained a series of steps (see Figure 3):

Steps of Additionality Tool

0. (only applicable to early start projects): Evidence that the incentive from the CDM was seriously considered in the decision to proceed with the project

1. Identification of alternatives to the project

2. Investment analysis, with the aim to determine that the project is not the most economically or financially attractive, ***or***

---

[153] EB 7, attachment A to Annex 6, later confirmed by decision 4/CMP.1
[154] EB 8, Annex 1
[155] EB 10, Annex 1
[156] EB 16, Annex 1

3. Barrier analysis, with the aim to check the existence of prohibitive barriers
4. Common practice analysis
5. Impact of CDM registration. Subsequently, the EB clarified that this step could be applied qualitatively[157].

The consolidated tool was revised in November 2005, which defined that step 0 would even be fulfilled if the project only could state the objective to mitigate climate change. In the second revision of the tool in February 2007[158], step 0 and 5 were removed. Barriers that could be assessed under step 4 were described more clearly (see Box 6).

Examples of Barriers

Box 6: Examples of barriers that prevent project implementation

- Similar activities have only been implemented with grants or other non-commercial finance terms
- No private capital is available from domestic or international capital markets
- Process/technology failure risk in the local circumstances is significantly greater than for other technologies

Validators have to document the Additionality Check in Validation Report

It was also stated that if the CDM does not alleviate the identified barriers that prevent the project, the project is not additional. Moreover, it was added that DOEs should carefully assess and verify the reliability and creditability of all data, rationales, assumptions, justifications and documentation provided by project participants and document conclusions transparently in the validation report (see also discussion about validation and verification standard in section 2.2.3).

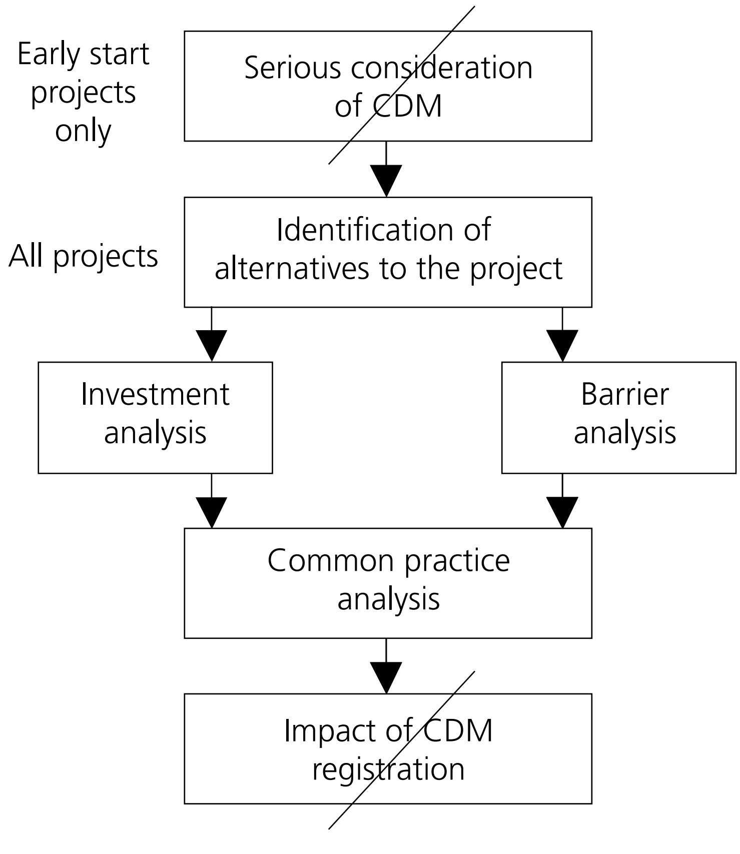
Serious Consideration of CDM

Alternatives to Project

Investment or Barrier Analysis

Common Practice Analysis

Figure 3: Steps in the consolidated additionality tool and changes over time



[157] EB 17, para 17
[158] EB 29, Annex 5

EB wants the Tool to be used

COP stresses its voluntary Character

EB has approved many methodologies that require the use of the consolidated additionality tool, as the use of the tool was proposed by the methodology developers. Methodology developers did not want to run the risk of suggesting new approaches for additionality determination. So there has been a tendency for the additionality tool to become mandatory. However, a mandatory character of the tool has repeatedly been rejected by COP/MOP[159]. In the same spirit, COP/MOP has consistently repeated the need for new proposals to demonstrate additionality[160] .

Combined Baseline Scenario and Additionality Tool – Limited Applicability

EB 27 approved a further "Combined tool to identify the baseline scenario and demonstrate additionality" in October 2006[161]. This tool is only applicable if all potential alternative scenarios are available to the project developers[162], which is often not the case. This tool thus has not been applied frequently. It has 4 steps (see Figure 4):

4 Steps of Combined Tool

1. Identification of alternative scenarios
2. Barrier analysis, with the aim to eliminate alternative scenarios which are prevented by the identified barriers
3. Investment analysis for the remaining alternatives
4. Common practice analysis

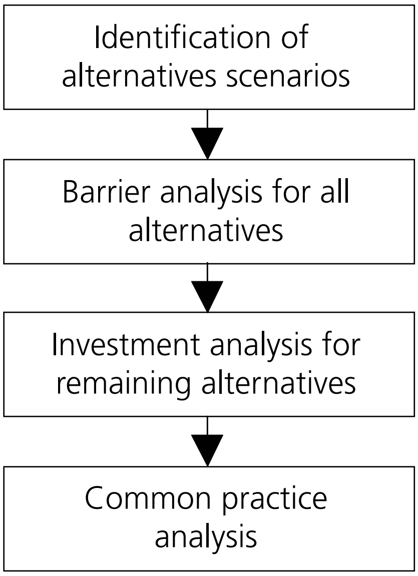
Figure 4: Steps in the combined baseline scenario identification and additionality tool

Scenario Identification

Barrier Analysis

Investment Analysis for remaining Options

Common Practice Analysis



Originally, the applicability conditions were more stringent as options had to be "under control" of the project developers.

[159] Decision 12/CP.10, para 9, 28; decision 7/CMP.1, with the latter stating that this even applies to methodologies that require use of the tool

[160] Decision 7/CMP.1, para 25-27, decision 1/CMP.2, para 16 (c)

[161] EB 27, Annex 9

[162] EB 28, Annex 14

3.2 Checking additionality determination through reviews of projects

Rejections due to Lack of Additionality

Projects failing to accurately demonstrate their project's additionality have been subject to requests for review by the EB and a sizeable share of rejections of projects is due to problems with additionality determination, affecting a number of different project types. Challenges abound in all steps of the additionality test.

Lack of Specification of Parameters for Investment Test

Regarding the calculation of financial parameters for the investment analysis, often not all investment cost and revenue parameters, discount rate and time horizon are specified that are required to derive the IRR transparently for all relevant alternatives. If the benchmark test is used, an internal company hurdle rate often is not adequately documented.

Prohibitiveness of Barriers not shown

Regarding the barrier test, project developers often list a host of barriers in very general form and do not provide an explanation why the barriers listed are prohibitive.

With respect of the common practice test, developers sometimes use a very narrow definition for assessment of similar projects.

Registration Practice of EB

The EBs approach to implementation of additionality determination has evolved over time, as the board has sought to establish a clear standard for valistion of key requirements. The Board has not always recognised potential review questions, and when it has done so it has struggled to in cases to establish and apply an evidential burden with regard to financial calculations has not been applied consistently in all cases.

Wind Project rejected due to Description of its Attractiveness in Company Report

Regarding projects using ACM 0002, two wind power projects (UNFCCC no. 0221 and 0224) were rejected by the Board, probably on the basis of contradictory external statements. The project developer's annual report described the projects as follows: "The project is extremely beneficial on a standalone basis and has a payback period of three years with an internal rate of return in excess of 28 per cent. In addition to hedging Bajaj Auto's power costs, this investment also provides sales tax incentives and an income tax shield." CDM or carbon credits were not mentioned in the report. Nevertheless a large number of wind projects arguably with similar characteristics have been registered perhaps without a similar level of scrutiny (see box 7).

Wind Project registered despite very high IRR

Box 7: Registration of wind power projects despite high IRR

A 125 MW wind project in the Indian state of Karnataka (UNFCCC no. 0315) applied the benchmark test and argued that its IRR was 7.3%. The project was registered, though there are reasons to suggest that IRR calculation did not take into account that such as wind energy investments attract accelerated depreciation of 80% in the first year and get a 10 year income tax holiday IRR in PDD. An independent observer has calculated that IRR with these tax benefits and realistic investment costs could be in the region of 22%.

Regarding energy efficiency, two projects using AMS II.D were rejected due to a failure of applying the barrier test (UNFCCC no. 0311 and 0317). Waste heat recovery projects using ACM 0004 have generally been registered even though some projects exhibit features that put their additionality in doubt (see Box 8).

Waste Heat Recovery Project registered despite artificial Transfer Price

> **Box 8:** Waste heat recovery projects registered despite artificial transfer pricing
>
> The JSW Vijayanagar Steel plant in India uses waste gas for electricity production (projects UNFCCC no. 0325 and 350). The projects were registered without a review in early 2007. In this case JSW Steel operates the steel plant, JSW Energy the power plants. Due to regulatory reasons in the Indian power sector, JSW Steel charges JSW Energy a transfer price for the waste gas equal to the coal price that would have been paid for coal delivered to the power plants. Because JSW steel may be able to provide the gas at no cost except an investment in a gas storage tank, which pays off after just 100 GWh of electricity produced from waste gas there are reasons to question the IIR calculation.

Cement Blending Projects increasingly rejected

There has been a shift in the treatment of projects using methodology ACM 0005 on blending of cement with fly ash or slag. While in 2006 and early 2007, 14 projects of this type were registered and one rejected, since then five projects have been rejected and none registered, mainly due to an evolution in policy with regard to the application of the barrier test (see box 9).

Cement Blending Project rejected due to unsubstantiated Barrier

> **Box 9:** Reasons for rejection of cement blending project
>
> A project blending with blast furnace slag in Brazil (UNFCCC no. 0754) listed the following barriers:
>
> - Development of logistics for additives supply is costly and difficult
> - Use of slag increases the production costs of cement
>
> However, the project developer argued in an external report that use of additives enhanced profitability. When a request for review was made, the company argued that long distance transport of slag increased its costs. However, the data provided could not corroborate this argument.

Biomass Power Projects rejected due to flaws in Benchmark Analysis

Several biomass power projects have been reviewed or rejected by the EB mainly because of problems related to the application of the benchmark analysis. The project UNFCCC no. 1033 was under review due to the use of a spot market electricity tariff in the benchmark analysis, but assuming that the tariff is fixed in the long term. Under such circumstances, the EB could argue that the project proponent should have taken into account that using a spot market electricity tariff in the benchmark analysis does not reflect price fluctuations over time. The project UNFCCC no. 1014 was rejected by the EB where the project proponent argued that the minimum investment rate of return used in the palm oil industry should be a valid benchmark for an investment in the electricity supply industry, based on the underlying assumption that “project activities under similar conditions developed by the same company should be allowed to used the same benchmark”. However, according to the EB, the proponent failed to properly demonstrate why.

4. Methodologies

Methodology Case Law developed over Time

Baseline methodologies have to address the challenge of quantifying a counterfactual situation, whose characteristics can never be proven ex post. Therefore, a general approach has to be developed that is relatively robust with respect to simulating the situation that would have existed in the absence of the project. Such an approach has the aim of limiting the incentive for projects to claim emission reductions that are higher than those actually achieved. Over the last years, such approaches have developed through case law. They have become increasingly complex over time.

4.1. Principles underlying methodology development

Application of a methodology should result in a baseline scenario that "reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity". To achieve this target, principles have been defined that a methodology shall fulfil. These principles are reflected in the methodology desk review form.

Methodology Principles

The methodology has to be described in a ***transparent*** manner. It should be ***conservative*** and internally ***consistent***. Calculations and assumptions used have to be ***appropriate*** and ***adequate***. Data have to be ***accurate*** and ***reliable***; uncertainties shall be limited. Preferably data should be ***measurable***.

Lower Bound of 95% Confidence Interval determines Conservative Data

Some of these principles have been operationalized through procedures that have evolved over time. Transparency means that assumptions are explicitly explained and choices are substantiated[163]. Conservativeness means that in the case of doubt, values that generate a lower emission reduction, e.g. through lower baseline projection or higher project emissions shall be used[164]. It is increasingly interpreted in the sense that a 95% confidence interval has to be calculated for a parameter[165] and the bound is to be chosen which leads to a lower emission reduction calculation. For small-scale projects. the confidence interval is defined by one standard deviation[166].

Use of IPCC Default Factors

Uncertainty is often to be limited by using default factors from the 2006 IPCC guidelines for national greenhouse gas inventories, as required by the small scale rules (see 4.3. below). Measurability is given a high value by the CDM EB, which has led to instances where costly and not easily available measurement equipment has to be used. Scientific evidence in form of references to articles in peer-reviewed journals has played an important role regarding approval of methodologies or definition of parameter values.

Internal consistency has so far played a more important role than consistency across methodologies. However, the EB is addressing the latter through definition of tools for calculation of certain processes that are to be applied for all methodologies alike. So far, besides the additionality tools discussed in Chapter 3 tools have been defined for emissions from flaring methane and methane emissions avoidance from solid waste landfilling (since 2006),

163 EB 5, Annex 3

164 Ibid.

165 EB 21, Annex 7 in the context of the use of regression analysis and EB 22, Annex 2 regarding parameter definition through sampling.

166 EB 23, Annex 33, para 11

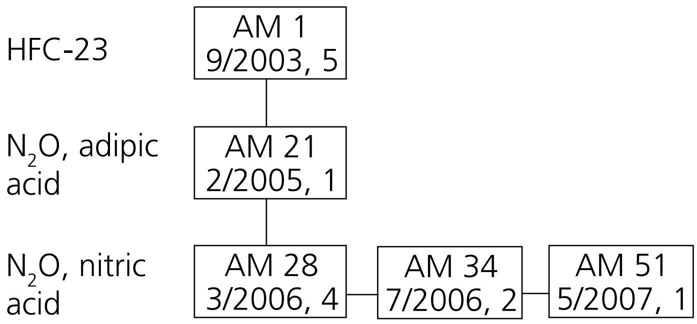
project emissions from electricity consumption and emissions from fossil fuel consumption (since 2007).

Methodology Case Law developed over Time

There has been a distinct development of methodologies over time, leading to “families” and family trees when one methodology spawns a whole series of other methodologies. Figures 5-14 show the families of methodologies in form of family trees. They are designed as follows: Each methodology is denoted by a box. The boxes show the name of the methodology, its approval date and the number of versions since its first approval. A stroke through a methodology denotes that it has been withdrawn. Vertical lineages show influences across project types whereas horizontal lineages show methodology development within one project type.

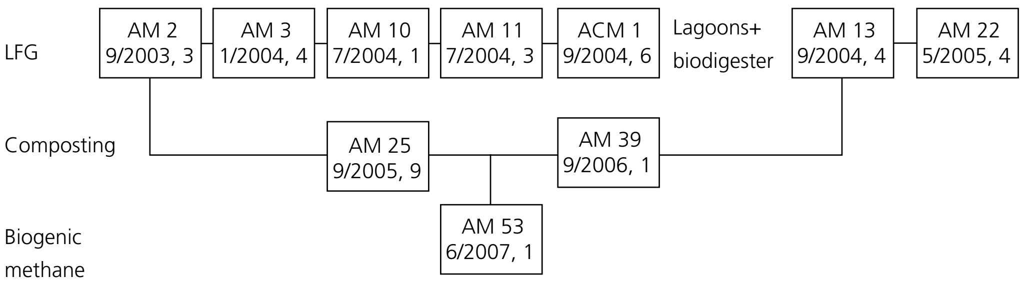
Methodologies for Industrial Gases

Figure 5: Industrial gas family tree



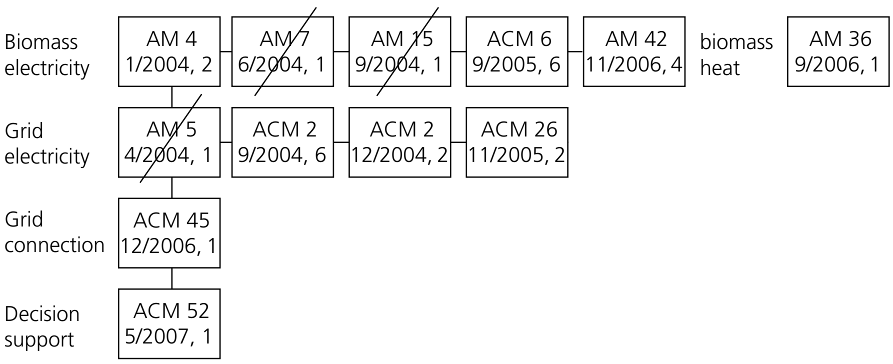
Methodologies for Landfill Gas and Wastewater

Figure 6: LFG and wastewater family tree



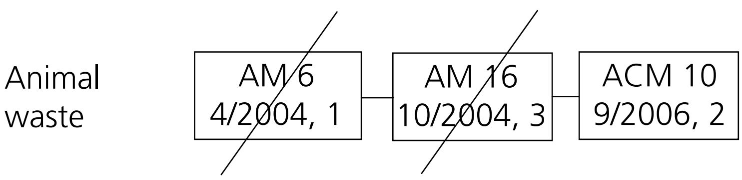
Methodologies for Renewable Electricity fed into a Grid

Figure 7: Renewable grid electricity family tree



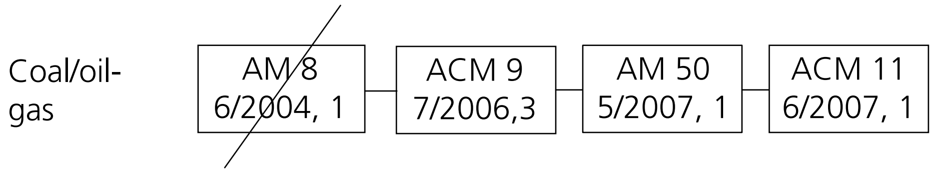
Methodologies for Methane Capture from Animal Waste

Figure 8: Animal waste family tree



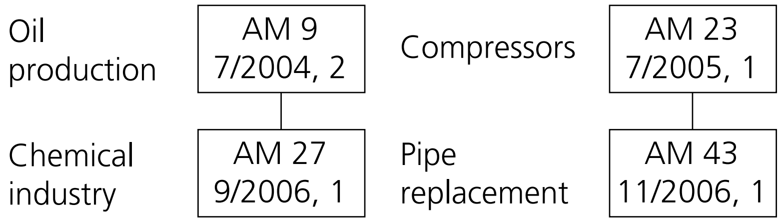
Methodologies for Fuel Switch

Figure 9: Fuel switch family tree



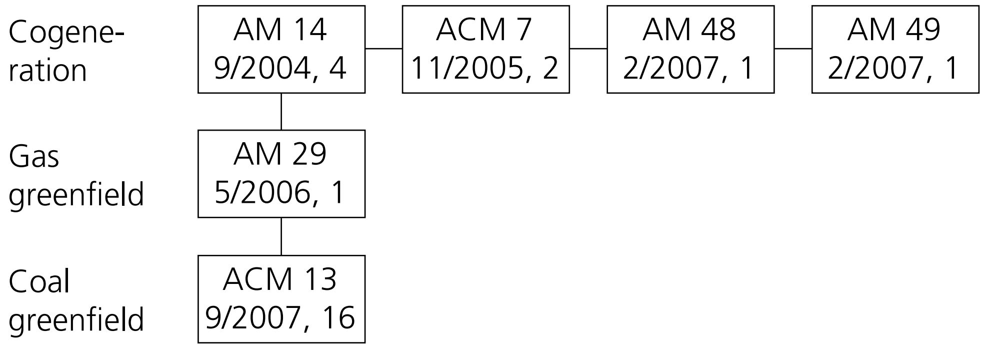
Methodologies for Gas Flaring and Gas Leak Reduction

Figure 10: Gas flaring and gas leak reduction family trees



Methodologies for Efficient Fossil Fuel Power Plants

Figure 11: Fossil power plant efficiency family tree



Methodologies for Process Energy Efficiency

Figure 12: Process energy efficiency family tree

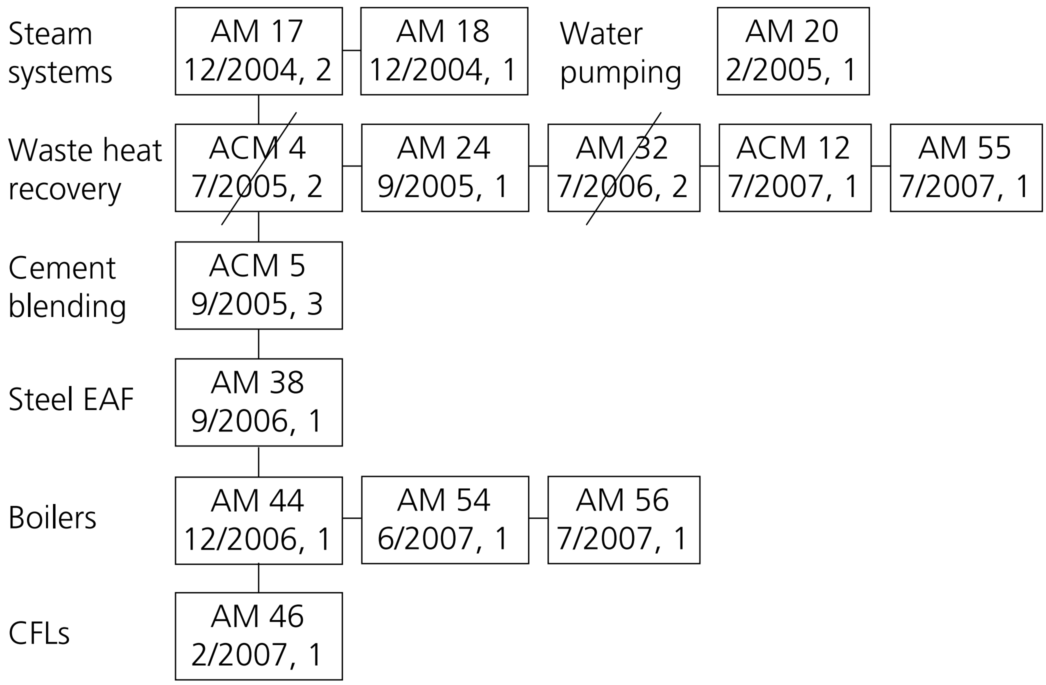


Figure 13: Renewable chemical feedstock family tree

Methodologies for Renewable Chemical Feedstocks

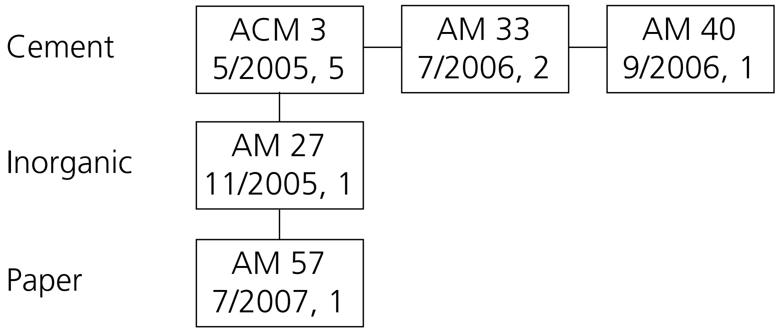
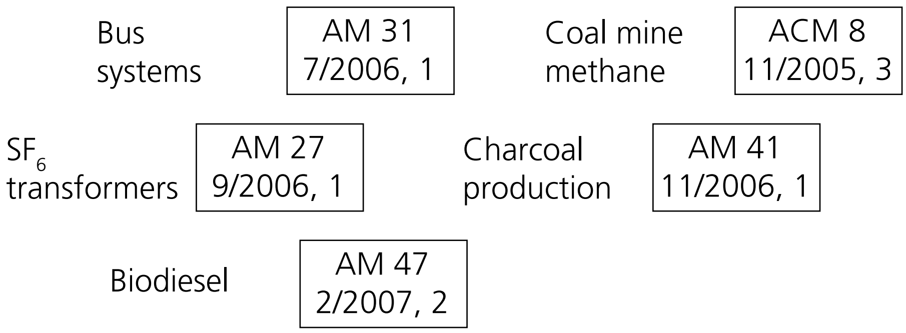


Figure 14: Singletons

Other Methodologies



Some of the singletons could be the basis for a family tree in the future, such as transport and liquid biofuel.

4.1.1 Baseline methodology approaches in the Marrakech Accords

Use of Approaches para 48 (a)-(c) of Marrakech Accords

48 (c) rarely used due to negative Experience in early Rounds of Methodology Submission

A baseline methodology is an application of the three approaches under paragraph 48 of Marrakech Accords[167]. The approach should be the one "most consistent with the context of applicable project types, and most consistent with underlying algorithms and data sources"; in each methodology submission it has to be specified[168]. In practice, the approaches 48(a) and (b) are underlying most methodologies. Normally, 48 (b) is covered through additionality testing. 48 (c) has been used rarely, despite being theoretically attractive as many researchers have supported the principle of setting such a benchmark. This is due to the fact that in the early phase of methodology submissions, the first methodology using 48 (c), NM 0003 on CO_2 use in a methanol plant, was rejected on additionality grounds. NM 13 (methane capture from wastewater of palm oil mills) and NM 34 (methane capture from pig manure) set out with approach 48 (c) with NM 13 being rejected and NM 34 switching to approach 48 (b) during the revision process that led to AM 16. Thus, nobody dared to use 48 (c) again until the submission of NM 217 on supercritical coal power plants which led to ACM 13.

[167] EB 5, Annex 3
[168] EB 10, Annex 1

Interpretation of top 20% in Approach 48 (c)

Top 15% instead of top 20% used in First Approved Methodology using Approach 48 (c)

Box 10: ACM 13 modifies the approach 48 (c) and previous EB guidance

In approach 48 (c), the emissions factor shall be[169] the lower of

1. output-weighted average emissions of the top 20 per cent of similar project activities undertaken in the previous five years in similar circumstances
2. output-weighted average emissions of similar project activities undertaken in the previous five years under similar circumstances that are also in the top 20 per cent of all current operating projects in their category.

No methodology was ever approved using that approach. The EB did apply this approach in the case of ACM 13 on greenfield fossil power plants, where the benchmark group was reduced to the top 15% performing power plants (excluding cogeneration plants and including power plants registered as CDM project activities) among all power plants constructed in the previous 5 years that have a similar size, are operated at similar load and use the same fuel type as the project activity.

4.1.2 Baseline scenario definition

Choice of Baseline Scenario has to be explained

Baseline has to be Output-based

Suppressed Demand Question

The definition of the baseline scenario is a key step in any baseline methodology. Each methodology has to include an explanation of how the baseline is chosen[170]. The additionality test should show that the project is not identical with the baseline scenario[171]. As the baseline scenario should not grant CERs for decreases in activity levels outside the project activity or due to force majeure, the baseline should be defined on an output- or product-linked basis as an emissions factor per unit of output, at least when the project produces and sells an output. This has given rise to a discussion about whether in situations of suppressed demand, only that demand should be taken into account in determining the baseline activity level. The EB registered a project (Kuyasa low-cost urban housing energy upgrade project, Khayelitsha (Cape Town; South Africa), UNFCCC no. 0079) where the baseline is calculated on the basis of an activity level (indoor temperature of houses due to heating) that has increased due to the project.

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[169] EB 8, Annex 1
[170] EB 8, Annex 1
[171] Ibid. According to EB 17, para 16, additionality determination shall be consistent with the determination of a baseline scenario.

National Policies and Regulations in the Baseline

E+ E- rule

The consideration of national policies and regulations in determination of the baseline scenario is a key issue. "National and/or sectoral policies and circumstances are to be taken into account on the establishment of a baseline scenario, without creating perverse incentives"[172], this is commonly known as the E+/E- rule. For national and/or sectoral policies or regulations that give comparative advantages to more emissions-intensive technologies or fuels over less emissions-intensive technologies or fuels implemented since the adoption of the Kyoto Protocol (December 11, 1997), the baseline scenario should refer to a hypothetical situation without the policy. The same applies for policies giving comparative advantages to less emissions-intensive technologies over more emissions-intensive technologies implemented since the adoption of the Marrakech Accords (November 11, 2001)[173]. The EB has never clarified whether this rule also applies to the application of the additionality test, e.g. whether a subsidy for renewable energy should be disregarded in the investment calculation. In many baseline methodologies, mandatory policies, regardless of their date of introduction, lead to an immediate change of the baseline to become equal with the project.

Greenfield vs. Retrofits

Definition of technical Lifetime

The baseline scenario depends on whether a project is retrofitting existing equipment or a greenfield installation. A retrofit should not increase the output or lifetime of the existing facility[174]. For any increase of output or lifetime of the facility which is due to the project activity, a different baseline shall apply. Lifetime should be determined either as typical average technical lifetime, taking into account common practices in the sector and country, e.g. based on industry surveys, statistics, technical literature or replacement practices of the project developer, e.g. based on historical replacement records for similar equipment[175]. For projects involving a large number of individual equipment installations, the baseline should reflect the expected improvements in emission characteristics for the equipment type as a result of replacements or retrofits of equipment in the absence of the project.

4.1.3 Project boundary

Unclear Definition of Project Boundary

The concept of project boundary and the definition of "under control of, significant and reasonably attributable" has not been specified in detail. Conservativeness should guide the choice of assumptions, for example the magnitude of emission sources omitted in the calculation of project emissions and leakage effects should be equal to or less than the magnitude of emission sources omitted in the calculation of baseline emissions[176].

Significant Emission Sources: 5% or 1%?

Significance of emissions sources to be covered has only been covered in the context of forestry projects, where a tool states that "GHG emissions are considered insignificant if their sum is lower than 5% of net anthropogenic removals by sinks"[177]. Many methodologies use a value of 1% of total emissions as threshold for a significant emissions source.

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172 EB 16, Annex 3
173 EB 22, Annex 3.
174 EB 8, Annex 1
175 EB 22, Annex 2
176 Ibid.
177 EB 31, Annex 16

4.1.4 Leakage

Unclear Definition of Leakage

As with the concept of project boundary, a detailed explanation of how to approach leakage has not been provided by the EB. After identification of leakage sources one has to explain which sources are to be calculated, and which can be neglected[178]. This has led to inconsistencies across methodologies, with some methodologies requiring a full life-cycle analysis, whereas in other methodologies it was seen as sufficient if emissions of one process level upwards and downwards were taken into account.

4.1.5 Monitoring, data sources and quality

Requirements regarding Data Sources

Data Vintages

Data are key to monitor emissions reductions and to apply a baseline methodology. They should be referenced with possible sources being official statistics, expert judgement, proprietary data, IPCC, commercial and scientific literature[179]. Data have to be SI units[180]. Vintages and spatial level have to be defined[181]. Regarding data vintages, it was discussed whether baseline parameters can be fixed ex-ante or have to be monitored ex post. "Ex post calculation of baseline emission rates may only be used if proper justification is provided. Notwithstanding, the baseline emission rates shall also be calculated ex-ante and reported in the draft CDM-PDD"[182].

Accuracy of Measurements

Data have to be conservative, adequate, consistent, accurate and reliable. For some methodologies, accuracy played an important role, for example in the context of measurement of methane content of flare exhaust gas. Generally, monitoring of methane emissions has been more demanding than of other greenhouse gases.

Standard Variables

Frequency of data collection and quality assurance/control procedures have to be specified. In this context, the specifications of the monitoring plan are important which should "reflect good monitoring practice appropriate to the type of project". A list of 56 standard variables has been specified[183]. Alternatively ISO or other standards can be used for variable name definitions. Methodologies should specify a priority order for use of alternative data if the preferred sources are not available[184].

Baseline and Monitoring Methodology belong together

A strong link between baseline and monitoring methodologies is to be provided[185]. If project participants want use different combinations of approved baseline and monitoring methodologies they have to get Meth Panel and EB approval. No one has ever asked for such approval as over time it has become clear that monitoring is intrinsically linked to the baseline methodology. The submission forms have been revised accordingly (see section 4.2)

[178] EB 20, Annex 2
[179] EB 8, Annex 1
[180] EB 9, Annex 3
[181] EB 8, Annex 1
[182] EB 10, Annex 1
[183] EB 24, Annex 16
[184] EB 9, Annex 3
[185] EB 10, Annex 1

4.2. Submission of a new methodology: the bottom-up process for large scale methodologies

Frequent Changes in Submission Process

Desk Review and Meth Panel Recommendation

Feedback Loop

Methodology Grading

Submission Fee

Longer Deadlines, limited Resubmissions

Increased Role of the UNFCCC Secretariat in Methodology Evaluation

The bottom-up process of submission of methodologies has seen considerable changes over time; it has been changed 12 times in 4 years[186], but often only regarding administrative issues such as fee levels. Originally, a validator would do a pre-check of a new methodology with an accompanying PDD that would then be submitted to the Meth Panel, which would assign two members and two desk reviewers for evaluation of the methodology. The Meth Panel would provide a recommendation to the EB. A feedback loop between the Meth Panel and the project developer was added by EB 10, but kept very short (7 days)[187]. At EB 13, a pre-check by 2 Meth Panel members was introduced[188], to be further tightened by EB 14[189]. At the same meeting, the methodology submission form was split in two parts for baseline and monitoring methodology[190]. EB 15 decided to have the pre-check only done by one Meth Panel member[191]. At EB 20, grades A-C were introduced (A = approval, B = revision, C = rejection) and deadlines expanded due to the growing workload of the Meth Panel[192]. EB 21 introduced a baseline submission fee of 1000 $ and allowed the validator to do the pre-check. Moreover, the Meth Panel was allowed to ask the project developers for additional technical information before entering into the feedback loop. A B-rated methodology could now only be resubmitted once, within 5 months[193]. EB 23 prolonged the deadline for feedback on the preliminary recommendation to 4 weeks[194]. At EB 32, a thorough revision was made. The Meth Panel pre-checking the submission receives a pre-assessment done by the Secretariat. Once it has passed the pre-check, a methodology is assessed by the Secretariat which is allowed to ask project developers for clarifications. This assessment is reviewed by 4 Meth Panel members before desk reviewers are chosen by the chair and vice chair of the Meth Panel. Before the feedback loop starts, the Secretariat can ask the project developers for further information. The EB will only decide on A or C cases[195].

Resource Availability shapes Process

The changes in the submission procedure mirror the resource availability of the Meth Panel and the Secretariat. When the Meth Panel was swamped with methodology submissions in 2004 and 2005, additional gateways were introduced, deadlines expanded and communication with project developers strictly limited to keep the workload manageable. With the increase of CDM expert staff at the Secretariat from 2006, assessment work could be transferred from the Meth Panel to the Secretariat and new communication channels to the developers were opened.

186 It was first defined by EB 8, Annex 2.
187 EB 10, Annex 5
188 EB 13, para 22c
189 EB 14, para 18
190 EB 14, Annex 6
191 EB 15, para 13
192 EB 20, Annex 2
193 EB 21, Annex 2
194 EB 23, Annex 2
195 EB 32, Annex 13

4.3 Initial top-down-development of small-scale methodologies turning into a bottom-up process

Top-down Methodology Development for Small-scale Projects

Appendix B to the simplified modalities and procedures for small-scale CDM project activities specified a set of 12 methodologies for small-scale CDM project types as well as rules for additionality determination[196]. The methodologies have been revised repeatedly over time.

4.3.1 Principles for small-scale methodologies

No Leakage Calculation except for Biomass

Data Source Hierarchy

The project boundary is limited to the physical project activity. Leakage can be disregarded except for projects using biomass. If data for equipment performance required in the methodology are not available, a hierarchy of alternative data is specified, starting with national standards, continuing with international standard (ISO or IEC) and finishing with manufacturer's specifications that have to be certified by national or international certifiers. For emissions factors, the current values of the "IPCC Good Practice and Guidance and Uncertainty Management in National Greenhouse Gas Inventories" and the "IPCC Guidelines for National Greenhouse Gas Inventories" have to be used.

Bottom-up Methodology Development possible

Moreover, rules for development of further small-scale methodologies were defined. Project developers could propose additional project categories or revisions to a methodology through a request in writing to the EB providing information about the technology/activity and proposals on how a simplified baseline and monitoring methodology would be applied to this category.

4.3.2 Small-scale methodology rule development over time

Perceived high Success Share of Small-scale Methodologies led to Increase in Bottom-up Submissions

Key methodological concepts such as use of the operating and build margin for electricity grids, are part of the initial set of small-scale methodologies. They have set the scene for the development of large-scale methodologies. However, for a considerable time, all attention focused on the development of large-scale methodologies. Only when project developers started to realize that submission of a small-scale methodology for a difficult project type was having a much higher chance of success than a large-scale methodology due to the inability of the Small-Scale Working Group (SSC-WG) to reject methodologies except in cases where the project type suggested was clearly non-eligible for CDM, bottom-up submissions of methodologies started. The first methodology was submitted in April 2005. Table 3 gives quantities of submitted methodologies and eventual EB decisions.

[196] EB 7, Annex 6

Table 3: Bottom up-use of small-scale methodology process

	2005	2006	2007
Methodology submissions	6	8	13
Approvals	3 (III.F, III.H, III.J)	–	3 (III.L, III.M, III.N)
Rejections	–	1	1
Initial revisions	1	4	11
Subsequent revisions	2	4	12
Integration in existing methodologies	1	2	–

Small-scale Submission Rules aligned with large-scale Rules due to high Submission Rate

As Table 3 shows, in 2007 the workload of the SSC-WG increased substantially due to the high number of revisions of methodologies that nevertheless did not lead to a higher rate of approvals. Thus the EB defined a new rule for submission of small-scale methodologies which essentially copies the large-scale submission process with methodology submission forms, one desk review and the SSC-WG functioning as the Meth Panel for small-scale methodologies, which can even reject proposed methodologies without the EB having to take an explicit decision[197]. Likewise small-scale baseline revision rules were aligned with the large-scale ones[198].

4.4 Revisions and clarifications of methodologies and deviations

Definition of Terms Revision, Clarification and Deviation

A revision should be done if the project is "broadly similar" to the projects to which the approved methodology is applicable. The revisions should not lead to "exclusion, restriction, narrowing of the applicability conditions". If the revision would add new procedures or scenarios to more than half of the sections of an approved methodology, a new methodology shall be proposed. Clarifications shall be requested if a methodology is unclear or ambiguous. A request for deviation is suitable for situations where a change in the procedures for the estimation of emissions or monitoring procedures is required due to a change in the conditions, circumstances or nature of a registered project. It shall be project specific[199]. A revision of a monitoring plan needs to be done before CER issuance if the monitoring plan is not consistent with the approved monitoring methodology[200].

4.4.1 Revisions of methodologies

Approved methodologies have been revised frequently (see Table 4 and Figures 4-12) and the process for revision has also undergone significant changes.

[197] EB 34, Annex 8
[198] EB 34, Annex 7
[199] EB 30 (Annex 1) specified the differences between revisions of, clarifications of and deviations from an approved methodology.
[200] EB 31, Annex 12

Table 4: Methodology revisions

	2005	2006	2007
Requested by DOEs	3	32	27
Approved	2	8	12
Rejected	1	13	15
Initiated by Meth Panel/EB	15	21	6

All CDM Institutions can propose Revisions

Registered Projects not affected by Revisions

A revision can be proposed[201] by the EB, project developers or the Meth Panel, and the COP/MOP[202]. If the EB thinks that a methodology requires a significant revision but does not have the time or information to decide on a revision, it can put the methodology on hold. Up to two members of the Meth Panel are checking the proposed revision and prepare a recommendation that the Meth Panel is to consider at its next meeting. Revisions do not affect registered projects and projects submitted for registration. Revision rules apply to small scale methodologies as well[203]. The Secretariat prepares the draft revision for the Meth Panel[204]. The rule that there should be a minimum of 6 months between revisions, "where possible", only survived 6 EB meetings[205].

Grace Periods for Use of Old Methodology Versions prolonged over Time to 8 Months

With an increase in the frequency of methodology revisions that in extreme cases have led to a revision of a methodology in three subsequent meetings, grace periods for use of old versions have been expanded considerably: initially 4 weeks were granted after the date the methodology has been put on hold and no grace period existed at all for methodologies that had been revised[206]. Then the validity of the 4-week period was expanded to all cases of revision, including withdrawal of a methodology[207]. Subsequently, the period was expanded to 8 weeks, except for methodologies put on hold where it was kept at 4 weeks[208]. It was further prolonged by a few days as the date of revision was defined as the date of publication on the UNFCCC website instead of the date when the EB meeting took the actual decision[209]. Currently, the date of revision is 14 days after publication of the revision and the grace period for revisions and withdrawals[210] is 8 months for projects whose PDDs had been published for public comments using the previous version of the methodology[211].

[201] EB 19, Annex 3
[202] Only added by EB 21, Annex 6
[203] EB 23, Annex 3
[204] EB 32, Annex 15
[205] EB 28, Annex 16 introduced it, EB 32, para 32 scrapped it.
[206] EB 19, Annex 3
[207] EB 21, Annex 6
[208] EB 23, Annex 3
[209] EB 28, Annex 18
[210] Expansion to withdrawals was done by EB 31, Annex 2
[211] EB 30, Annex 2

4.4.2 Clarification of methodologies

Clarification essentially Task of the Secretariat Need for Deviation to be checked by DOE

Only validators are allowed to submit requests for clarification to the Meth Panel[212]. Over time, the Secretariat has got a larger role in providing clarifications: at first the Secretariat was only involved in preparation of the response[213], but now it has the power to determine that the "clarification is simple enough so as to not require the Meth Panel's consideration". The Secretariat's draft is sent to two Meth Panel members and the Chair, who then can approve the response. The EB tacitly confirms the response unless it takes up the matter actively[214].

4.4.3 Deviations from approved methodologies

EB can decide electronically

A DOE shall "prior to requesting registration of a project activity or issuance of CERs, notify the Board of deviations from approved methodologies and/or provisions of registered project documentation and explain how it intends to address such deviations"[215]. It also has to check whether instead of a deviation, a revision would be necessary and to calculate the impact of the deviation on the CER volume of the project. The Secretariat checks the request[216] and the EB chair decides whether the request has to be considered by a Panel or Working Group, whether further information is required from the submitting DOE or whether the EB can decide immediately, through electronic means[217]. With the decision, guidance will be published.

Deviations have led to important Rule Changes

Table 5: Deviations

	2005	2006	2007
Requested by DOEs	8	3*	8*
Approved	3	1	3
Partially approved	4	1	2
Rejected	1	1	2

* 5 different requests lodged on the same day referred to the same issue and are thus regarded as one request
** 32 different requests lodged on two subsequent days referred to the same issue and are thus regarded as one request. One request is still pending

Several key rules for methodology application are due to decisions on deviation requests, especially in cases of lacking data for calculation of baseline emissions factors.

[212] EB 20, Annex 6 defined the procedure for clarifications of approved methodologies.
[213] EB 32, Annex 15
[214] EB 34, Annex 3
[215] EB 21, para 66
[216] EB 24, Annex 30
[217] EB 22, Annex 20

5. Key elements and application of commonly used methodologies

Aims of Chapter

For any CDM project activity it is required to use either a methodology which was previously approved by the CDM EB or to propose a new methodology to the CDM EB for consideration and approval. Since a huge variety of projects has been developed or proposed under the CDM so far, numerous approved methodologies already exist and various new methodologies are under evaluation by the Meth Panel/EB. This chapter assesses selected, widely used approved methodologies. It describes their key features, challenges regarding their application to CDM projects and resulting changes of the methodology over time.

5.1 Background of methodology selection

Analysis of Sample of Methodologies according to Frequency of Use. Small-scale treated separately

As over 90 approved methodologies exist today, an assessment of all of them would lead to an unwieldy book of several hundred pages, we select a sample of commonly used methodologies for in-depth assessment. The selection was done by screening all existing approved methodologies. Due to the fact that small-scale methodologies have a different regulatory framework and different basic conditions compared to large-scale methodologies, this was done separately for large- and small-scale methodologies. The following criteria were used:

Share in Projects or Share in CER Volumes

1. The share of the number of projects using an approved methodology in all projects submitted for public comments; and
2. The share of the total amount of CERs expected until 2012 from all projects submitted for public comments, using an approved methodology.

5% Threshold

The threshold for inclusion of a methodology in the sample was set at 5%[219].

8 large-scale and 5 small-scale Methodologies assessed

By applying the described selection criteria, 8 large-scale and 5 small-scale methodologies were selected. Table 6 shows the selected methodologies including the title, version, number of related projects and amount of expected CERs till 2012.

[219] The UNEP RISØ CDM project pipeline available at www.cdmpipeline.org was used for this calculation (cut-off-date 27/08/2007). Due to the fact that some projects involve more than one approved methodology, the number of projects and the amount of expected CERs till 2012 cannot always be clearly allocated to one methodology. Therefore double counting of these criteria was unavoidable.

Table 6: Approved methodologies meeting the selection criteria

	Approved Methodology	Title of methodology and version	Number of projects	CERs till 20 (kt CO2)
Large Scale	AM0001	Incineration of HFC Waste Streams – Version 5.1	18	500,603
	AM0021	Baseline Methodology for decomposition of N20 from existing adipic acid production plants – Version 1	4	170,153
	AM20029	Methodology for Grid Connected Electricity Generation Plants using Natural Gas – Version 1	25	123,763
	ACM0001	Consolidated methodology for landfill gas project activities – Version 6	107	150,612
	ACM0002	Consolidated methodology for grid-connected electricity generation from renewablesources –Version 6	607	517,389
	ACM0006	Consolidated methodology for electricity generation from biomass residues – Version 6	146	81,425
	ACM0008	Consolidated methodology for coal bed methane and coal mine methane capture and use for power (electricity or motive) and heat and/or destruction by flaring – Version 3	41	158,587
	ACM0012	Consolidated baseline methodology for GHG emission reductions for waste gas or waste heat or waste pressure based energy system – Version 1	3	1,641
Small Scale	AMS-I.C.	Thermal energy for the user or without electricity – Version 12	114	26,018
	AMS-I.D.	Grid connected renewable electricity generation – Version 12	669	137,876
	AMS-II.D.	Energy efficiency and fuel switching measures for industrial facilities – Version 13	81	7,264
	AMS-III.D.	Methane recovery in agricultural and agro industrial activities – Version 13	183	17,615
	AMS-III.E.	Avoidance of methane production from biomass decay through controlled combustion – Version 13	49	29,932

* Includes registrations "as corrected"

** One further rejection was withdrawn in 2007

It should be noted that ACM0012 is a newly consolidated methodology and thus does not yet meet the criteria, but has been added to the list because the underlying methodology ACM0004 was very frequently used (227 projects; 214,849 kt CO_2 CERs until 2012).

Two Methodologies added

Nitric Acid – Monitoring Complexity

CFL Distribution – PoA Character and Huge Complexity

In addition to the methodologies in Table 6, we included two methodologies in the assessment, even though they currently do not meet the 5 % criterion[220]. AM0034 (Catalytic reduction of N_2O inside the ammonia burner of nitric acid plants – Version 2) was considered to be worth attention, because it has recently been applied to a number of projects and has unusual, quite demanding monitoring requirements. The second additional methodology is AM0046 (Distribution of efficient light bulbs to households – Version 1). It was chosen because of its important role of being a precedent for CDM programmes of activities. It is also notable for its huge complexity and the fact that it might never be used as project developers will prefer using small-scale methodology AMS-II.C instead.

Definition of seven Methodology Bundles for Analysis

In order to show commonalities and differences as well as interactions among methodologies of a similar category, the selected methodologies were subsumed into 7 bundles. To enable a comprehensive analysis of the historical development of newly consolidated ACM0012 in bundle 3, the underlying, withdrawn methodology ACM0004 needed to be taken into account. All bundles with the related methodologies are depicted in Table 7.

Table 7: Bundles of approved methodologies to be assessed

Bundle 1: Grid-connected power generation • AM0029 • ACM0002 • AMS-I.D
Bundle 2: Industrial gases • AM0001 • AM0021 • AM0034
Bundle 3: Energy efficiency • AM0046 • ACM0012 (ACM0004) • AMS-II.D
Bundle 4: Methane recovery/avoidance • ACM0001 • AMS-III.D • AMS-III.E
Bundle 5: Coal bed/mine methane • ACM0008
Bundle 6: Biomass generation • ACM0006
Bundle 7: Thermal energy for users • AMS-I.C

220 In an update of the guidebook, we could look at the biofuel methodology AM0047. If its applicability conditions are expanded, it could eventually give rise to an important CDM project category. Secondly, it touches upon many new issues (emissions from cultivation of biomass, exports of biomass to industrialized countries).

Subsequently each bundle will be analyzed in terms of the basic concept of the bundle and by describing each methodology within the bundle regarding its application, special features and historical development. Especially regarding challenges in methodology development, examples of practical application of methodologies will be given.

Power Generation Methodologies

5.2 Grid-connected Power Generation

5.2.1 Methodologies Analyzed

Large Scale	ACM 0002 (version 6) "Consolidated baseline methodology for grid connected electricity generation from renewable sources"
Large Scale	AM 0029 (version 1) "Baseline methodology for grid connected electricity generation plants using natural gas"
Small Scale	AMS-I.D (version 12) "Grid connected renewable electricity generation)"

5.2.2 Basic Concept

Category Description

Grid-connected Power Plants

No non-renewable Biomass

The category concerns grid-connected power generation projects, where a project displaces power in the grid system that the project power plant is connected to. Both new power plant construction and retrofit in existing plants are covered by the category. However, the category currently does not cover the situation in which a project yields emission reductions in a grid system other than the one the project power plant is connected to (see Box 11). In addition, it does not allow the baseline to be the use of non-renewable biomass because no agreement has been reached on treatment of leakage so far (e.g. the CDM could give perverse incentives to increase the non-renewable biomass use in the region)[221].

Export of Power to other Grids not yet covered

Box 11: Transboundary impact of the project power generation

There were several attempts to broaden the applicability of ACM0002 to renewable power projects that result in emission reductions in another non-Annex I country via power export.[222] The key issue is traceability of the impact of the project power plant, i.e. whether the displacement of power by the power generated by the project takes place in the receiving grid or in another connected grid. For this kind of project, MP 26 observed that it would be important to (i) verify the power which is delivered to the grid to which the project plant is exporting, and (ii) demonstrate that the exported power results in the displacement of generation in the grid to which the power is exported. Those attempts were not approved eventually, but MP 26/EB 31 recommended project participants to submit this kind of projects with requests for deviation. It remains to be seen if this project type can become eligible under the CDM.

[221] The non-renewable biomass issue was originally derived from small-scale projects, but the same issue applies to any power generation projects regardless its size or fuel type used.

[222] See e.g. AM_REV_0018, AM_REV_0029.

Methodological Concept

Power Generation times Difference in Emissions Factors

Emission reductions (ERs) by these projects are calculated as the amount of power generated by the project (MWh) multiplied by the difference between the emission factors of the baseline and project (tCO_2/MWh). Leakage may apply to some cases.

ERs	=	$MWh_{project}$	X	$[(tCO2/MWh)_{baseline}$	-	$(tCO2/MWh)_{project}]$	- *Leakage*
Emission Reductions		Project Power		Baseline Emissions per Unit Power		Project Emissions per Unit Power	Leakage

New Power Plants

New plant construction: For project activities that seek to construct new facility for power generation, the baseline scenario corresponds to the power that would have been delivered to the grid by the operation of grid-connected power plants and by the addition of new generation sources in the absence of the project.

Retrofits

Remaining Lifetime

Retrofit in existing plant: For project activities that seek to retrofit or modify an existing facility for power generation, the baseline is that the existing facility would continue to provide power to the grid at the historical average level until the time at which the generation facility would likely be replaced or retrofitted in the absence of the project. All project power generation above the historical average level would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources. From the baseline replacement or retrofit date onwards, the baseline is assumed to correspond to the project activity and the baseline power production is assumed to equal the project power production. Consequently, no emission reductions are assumed to occur during that period.

Baseline Emission Factor Calculation

Concept of Combined Margin

Operating Margin

Build Margin

The crux of the methodological challenge for this category resides in determining "avoided generation", or what would have happened in the absence of the power generation CDM project. The emission factor of avoided generation (or the baseline emission factor) is typically calculated based on the combined margin (CM) approach, which is a reflection of the following two effects caused by the project: (i) displacement of power in the connected grid which is generated by power plants operating on margin (i.e. operating margin, OM), and (ii) delay of future power generation capacity additions to the grid (build margin, BM). Since most power generation projects are likely to affect both the OM (in the short run) and the BM (in the long run), the baseline should reflect a combination of these effects.

5.2.3 ACM0002

Project Description

Broad Set of Renewable Power Technologies covered

ACM0002 covers a wide range of grid-connected renewable power generation technologies (e.g. hydro, wind, geothermal, solar, wave and tidal). Wind and hydro projects consists of a major share of the existing ACM0002 projects. Several geothermal projects and a tidal project are also observed in this category. No solar or wave projects have been submitted based on ACM0002 so far (status: 28/8/2007).

Applicability Conditions

Power Density Threshold for Reservoirs

ACM0002 (version 06) is applicable to grid-connected renewable power generation projects, where the geographic and system boundaries for the relevant power grid can be clearly identified and where information on the characteristics of the grid is available. The project power generation capacity must be larger than 15 MW. An additional applicability condition is applied to hydropower projects with construction of new reservoirs and/or enlargement of existing reservoirs. For such projects, the power density of the project shall be greater than 4 W/m^2 [223].The methodology is not applicable to projects that involve switching from fossil fuels to renewable energy at the project site.

Project Boundary

Definition of Grid

Connected Grids

The spatial extent of the project includes the project site and all power plants connected physically to the power grid system that the project plant is connected to. The project boundary typically consists of two sub-systems: (i) the project electricity system (PES) and (ii) the connected electricity system (CES). A PES is defined by the spatial extent of the power plants that can be dispatched without significant transmission constraints. Similarly, a CES is defined as a grid system that is connected by transmission lines to the PES and in which power plants can be dispatched without significant transmission constraints. For the purpose of the BM emission factor calculation, the spatial extent is limited to the PES, except where recent or likely future additions to transmission capacity enable significant increases in power imports. The OM emission factor shall be calculated by defining the spatial extent such as it includes the PES and the CES. Definition of grid boundaries has changed over time (see Box 12).

Within the project boundary, project participants shall only account for CO_2 emissions from fossil-fuel-fired power generation that is displaced due to the project. Further, additional emission sources shall be considered in geothermal power and hydropower projects.

Which is the relevant Grid?

Regional Grid to be used

Box 12: Problems with grid boundary definition

Project boundary definition relates to several important elements such as baseline data collection and achievable emission reductions. A request for clarification on ACM0002 (version 02) pointed out that there was no harmonized definition on the grid boundary setting for ACM0002 projects in India, where a layered dispatch system existed.[224] Different DOEs validated ACM0002 projects in India based on a different grid layer – national, regional, and state grid. It caused apparent inconsistency in emission reduction estimations[225] and data collection burden. The request for clarification triggered a revision of ACM0002 to clarify that in large countries with layered dispatch system, the regional grid definition should be used.

[223] Power density means the ratio of hydro power capacity installed to reservoir surface area.

[224] See AM_CLA_0001.

[225] For example, the North-Eastern regional grid in India had an emission factor of 0.42 tCO2/MWh in 2005, while the Indian national average grid emission factor was 0.85 tCO2/MWh. If a project in the North-Eastern grid used the entire national grid as the project boundary (which is not allowed now), it could have generated twice as much CERs.

Box 13: Exclusion of immaterial parts of a multinational grid

Grids providing less than 1% of Project Grid can be neglected

Data collection becomes cumbersome especially when the project power plant is connected to a multinational grid and the project boundary has to include all the CES connected to the PES. A request for revision of ACM0002 (version 06) sought to exclude parts of a multinational grid from which the PES imports power less than or equal to 1.0% of the total power consumption of the PES (i.e. immaterial parts of the multinational grid)[??].The request for revision was accepted by EB 31 and the revision is to be incorporated in the next version of ACM0002.

Baseline Scenario and Additionality

Renewable Power Generation Determines Energy Baseline

The baseline is the annual power generated by the renewable unit multiplied by the emission coefficient of the grid that the project power plant is connected to.

Additionality of the project shall be demonstrated by application of the latest version of the "Tool for the demonstration and assessment of additionality" (additionality tool).

Baseline Emissions

ACM0002 employs the CM approach for calculating the baseline emission factor to take into account the effects on OM and BM caused by the project.

Operating Margin

Operating Margin

ACM0002 specifies four different methods to calculate the OM emission factor: (i) dispatch data analysis, (ii) simple OM, (iii) simple adjusted OM, and (iv) average OM. These methods can yield strongly different results and thus the choice of method is crucial for determination of CER volume.

In any case, net electricity imports from the CES within the same host country(ies) shall be considered as follows:

Emission Factor for Electricity Imports from other Grids

- 0 tCO_2/MWh; or
- The emission factor(s) of the specific power plant(s) from which power is imported, only if the specific plants are clearly known; or
- The average emission rate of the exporting grid, only if the net imports do not exceed 20% of the total generation in the PES; or
- The emission factor of the exporting grid determined based on the CM approach, if the net imports exceed 20% of the total generation in the PES.

For imports from the CES located in another country, the emission factor shall be assumed to be 0 tCO_2/MWh.

Dispatch Analysis: Emission Factor of top 10% of Power Plants dispatched to the Grid

Dispatch data analysis: The dispatch data analysis should be the first choice if the necessary data (i.e. hourly dispatch data and dispatch order) is available. In this case, the OM emission factor is calculated as the hourly generation-weighted average emissions per power unit (tCO_2/MWh) of the set of power plants falling within the top 10% of the grid system dispatch order. Where the dispatch data analysis cannot be applied, project participants shall select any of the other three options subject to the

[226] See AM_REV_0027.

preconditions stipulated in ACM0002. As dispatch is usually done according to fuel costs, the top 10% dispatched will usually have a higher emission factor than the average fossil fuel power plant. Therefore, unless the system is dominated by renewable energy, the emission factor derived from the dispatch analysis will be higher than the emission factor generated through the other methods explained below.

Average of all fossil Fuel Plants, if those generate more than 50% of Grid Power

Simple OM: The simple OM method can be used if low-operating cost/must-run resources[227] constitute less than 50% of the total grid generation (i) in the average of the five most recent years, or (ii) based on long-term norms for hydropower production. The simple OM emission factor is calculated as the generation-weighted average emissions per power unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost/must-run power plants. This essentially means that the average emissions factor of all fossil fuel power plants is calculated.

If renewable Plants generate more than 50% of Grid Power, average of Fossil Fuel Plants only for Time where they are on Margin

Simple adjusted OM: If low-operating cost/must-run resources constitute more than 50% of the total grid generation and chronological load data for each hour of a year is available, the simple adjusted OM method should be applied. It is a variation of the simple OM method, where the power sources are separated into low-operating cost/must-run resources and other resources. The weighted average of these two sub-components are calculated where the weights are given by the part of the year when low-operating cost/must-run resources are on the margin and by the part when other resources are on the margin. This means that in a grid dominated by hydro, for the share of the time where hydro is on the margin, an emission factor of zero is applied. Thus the simple adjusted OM will always be lower than the simple OM.

Grid Average only as last Resort

Average OM: The average OM method is the option to choose only when all the others cannot be applied. The average OM emission factor is calculated as the generation-weighted average emission rate (tCO_2/MWh) of all generating sources serving the system, including low-operating cost/must-run power plants. In a grid which is partially served by renewable sources, the average OM will be lower than the simple OM

Strong Differences in Results of OM Calculation

Box 14: Impacts of different OM calculation methods

A grid is served by 10 power plants, all producing the same quantity of electricity per year. One plant is an old coal plant generating 1100 g CO_2/kWh, two plants are modern coal plants generating 900 g CO_2/kWh, three are gas plants generating 400 g CO_2/kWh, and four are hydropower plants. If the old coal plant runs as baseload, the dispatch data analysis would give an emissions factor of 1100 g CO_2/kWh. The simple OM would yield 683 CO_2/kWh and the average OM 410 g CO_2/kWh.

Ex ante or ex-post Calculation of OM allowed

Ex-ante vs. ex-post OM calculation: The simple OM, simple adjusted OM, and average OM emission factors can be calculated either ex-ante based on the most recent three year data for which data is available at the time of PDD submission, or ex-post and updated annually. The choice between ex-ante and ex-post vintage should be specified in the PDD and cannot be changed during the crediting period.

[227] Low-operating cost/must-run resources typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must-run, it should also be included in this list, i.e. excluded from the set of plants.

Build Margin

Build Margin: newest Plants providing 20% of Grid Electricity or last 5 Plants if generating more than 20%

The BM emission factor is to be calculated as the generation-weighted average emission rate (tCO_2/MWh) of recent capacity additions to the system. These capacity additions consist of either the five power plants that have been built most recently, or the power plant capacity additions to the system that comprise 20% of the system generation and that have been built most recently. The sample group that comprises the larger annual power generation shall be used.

Ex ante or ex-post Calculation of OM allowed

Ex-ante vs. ex-post BM calculation: The BM emission factor can be calculated either *ex-ante* based on the most recent information available at the time of PDD submission, or *ex-post* and updated annually. The *ex-post* calculation is allowed only during the first crediting period. For subsequent crediting periods, it should be calculated *ex-ante*. The choice between *ex-ante* and *ex-post* vintage should be specified in the PDD and cannot be changed during the crediting period.

Combined Margin

Weighting OM and BM: Default 50-50, for Wind and Solar 75-25

The CM emission factor is to be calculated as the weighted average of the OM and BM emission factors. The OM/BM weights are set 50% by default. But for wind and solar projects, the default weights are 75% for the OM and 25% for the BM due to their intermittent and non-dispatchable nature (see Box 15). Alternative weights can also be chosen upon justification[228].

Weighting for different Types of Renewables

Use average Plant Efficiency

Box 15: OM/BM weights for different project classes

ACM0002 has set default OM/BM weights as 50% since its original version, with possible alternative weights upon justification. Over time, several arguments and proposals have been made for the use of alternative weights. The salient example is the exclusive use of OM for small power generation projects arguing that small capacity additions would only have negligible impacts on future capacity additions to the grid. The issue was clarified by the guidance given by EB 22[229]. As per the guidance, project size is not a legitimate basis for changing the OM/BM weights. the other hand, timing of project output, predictability of project output, and suppressed demand can be important factors in determining alternative weights.

The OM weight can be increased for highly off-peak projects (e.g. solar PV projects in evening peak regions, seasonal biomass generation during off-peak seasons) or projects with output of an intermittent nature (e.g. wind or solar projects). The BM weight can be increased for highly on-peak projects (e.g. air conditioning efficiency projects) or project under suppressed demand that are expected to persist through over half of the first crediting period. However, neither weight can exceed 75% during the first crediting period given that it is unlikely that a project will impact either the OM or BM exclusively during the period.

[228] See ACM0002 (version 06) for further guidance.

[229] See EB 22, Annex 2.

Combined Margin Calculation under Data Constraints

Data Availability Problems in Brazil and China

The following two cases (see Boxes 16 and 17) describe challenges encountered in the methodology application. Both cases are related to CM calculation under data constraints. Some key points are summarized below. However, it should be noted that these are the alternative approaches deemed appropriate in the context of Brazil and China. They might not be valid in other countries.

The project boundary could exclude power plants where necessary data for emission factor calculation is not publicly available. However, it should be justified that the project is unlikely to affect the excluded power plants. In addition, it is also important that the selected grid boundary consists of a majority share of the total installed capacity in the relevant geographical area.

Data Hierarchy

In the absence of plant-specific data (e.g. fuel consumption, power generation), the following approach could be considered as alternatives for grid emission factor calculation:

- OM calculation: Calculate the average emission factor for the grid for each fuel type (based on the average efficiency of the existing power plants); and
- BM calculation: Apply conservative proxy for power plant efficiency for each fuel type (e.g. the efficiency level of the best technology commercially available in the relevant geographical area) to calculate fuel consumption necessary for the BM calculation. The use of the average efficiency of existing power plants is unlikely to be accepted because it would not lead to conservative BM calculation.

In case plant-specific power generation data is not publicly available, more aggregate data (e.g. capacity addition from one year to another) could be used as an alternative for the selection of power plants for the BM calculation.

CM Calculation in Brazil

National Grid Definition in Brazil

Default Plant Efficiency Factors for Brazil

Box 16: OM/ BM calculation where the necessary data is not publicly available (Brazil)

"Request for guidance: Application of AM0015 (and AMS-I.D) in Brazil"[230] asked for the following two deviations: (i) electricity system boundary for Brazil be restricted to National Electricity System Operator (ONS), and (ii) average plant efficiency of power plants by fuel types be used in stead of actual fuel consumption. These two deviations are due to the fact that (i) the ONS dataset does not include power plants that are locally dispatched and the data for the remaining plants is not publicly available, and (ii) the fuel consumption data of the relevant power plants is not publicly available.

The first deviation was accepted based on the following justifications:

- ONS represents about 80% of the total installed capacity; and
- The remaining plants outside ONS were unlikely to be affected by the project because they were operating based on power purchase agreements which were not under control of the dispatch authority, or located in non-interconnected systems to which ONS has no access.[231]

The second deviation was not accepted for calculation of the BM emission factor because it would not lead to conservative estimation of emission reductions. Instead, the EB recommended the use of conservative proxy for power plant efficiencies to calculate the BM emission factor for grid electricity in Brazil:

- Combined cycle gas turbine power plants: 50%
- Open cycle gas turbine power plants: 32%
- Sub-critical coal power plants: 33%
- Oil based power plant sub-critical oil boiler: 33%

[230] See "Request for guidance: Application of AM0015 (and AMS-I.D) in Brazil", available at: http://cdm.unfccc.int/UserManagement/FileStorage/66CDZWPJFJOOUFJ8HALRB1VZV7UC84

[231] See the EB response to the request for deviation, available at: http://cdm.unfccc.int/UserManagement/FileStorage/AM_CLAR_IF26PUYWE8666VS24I68BM8WBDWJTO.

CM Calculation in China

Efficiency Proxy: Best commercially available Technology

Capacity Addition accepted Proxy for BM

Box 17: OM/ BM calculation where the necessary data is not publicly available (China)

"Request for guidance: Application of AM0005[232] and AMS-I.D in China"[233] requested, among others, the following two deviations: (i) use of average efficiency of existing power plants in the grid as proxy for estimating fuel consumption, and (ii) use of annual capacity additions during the last three years for estimating the BM emission factor.

Similar to the Brazilian case described above, the first deviation was not accepted but the following alternative approaches were suggested by the EB:

- For the OM calculation, the average emission factor for the grid for each fuel type can be used; and
- For the BM calculation, use the best technology commercially available in the provincial/ regional or national grid of China, as a conservative proxy, for each fuel type.

With regards to the second deviation, the alternative approach was accepted based on the justification that the group of power plants to be considered for the BM calculation could not be selected as no plant specific power generation data was publicly available. The capacity addition from one year to another (i.e. the annual capacity addition over the last three years) was accepted as the basis for the BM calculation[234].

CDM Projects in Combined Margin Calculation

CDM Projects are not considered in OM and BM

ACM0002 stipulates that registered CDM projects shall be excluded from both OM and BM calculation. As per the underlying CDM principle on additionality, the baseline scenario should reflect the case that would have happened without the CDM project. This implies that the baseline scenario does not need to take into account registered CDM projects in baseline emission calculation. This is because such CDM projects would not have happened without the CDM, hence do not represent the baseline. This clear guidance has set important precedence on treatment of registered CDM projects in baseline emission calculation, but the MP/ EB has recently made a decision against this guidance for a specific project type (see Box 18).

For new Coal Plants, BM has to include CDM Projects

Box 18: Inclusion of CDM project power plants in baseline emission calculation

ACM0013 "Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology (version 01)" was approved, with a vote of 8:2 at EB 34, after a lengthy debate on whether coal should get credits under the CDM. Interestingly, the final outcome requires the inclusion of registered CDM project power plants in the sample group for baseline emission calculation. This decision wants to ensure that "renewable resources projects are neither impacted nor jeopardized and the potential for the application of this methodology in a particular geographic area decreases, as more of these projects are registered under the CDM" as per the explanation given by EB 34[235].

232 AM0005 was later consolidated into ACM0002.

233 See "Application of AM0005 and AMS-I.D in China", available at: http://cdm.unfccc.int/UserManagement/FileStorage/6POIAMGYOEDOTKW25TA20EHEKPR4DM.

234 See the EB response to the request for deviation, available at: http://cdm.unfccc.int/UserManagement/FileStorage/AM_CLAR_QEJWJEF3CFBP1OZAK6V5YXPQKK7WYJ.

235 See EB34.

Project Emissions

With the exceptions of geothermal and hydropower projects, the project emissions of this project category are assumed to be zero. The following project emission sources shall be taken into account for geothermal and hydropower projects:

Geothermal Plants have Project Emissions from Steam

Geothermal power: (i) Fugitive emissions of CO_2 and CH_4 due to release of non-condensable gases from the produced steam, and (ii) CO_2 emissions from operation of the geothermal power plant.[236]

Hydro Reservoirs with Power Density of 4-10 W/m² have default Emission Factor of 90g CO_2/kWh

Hydropower: Fugitive emissions of CO_2 and CH_4 due to the rotting of organic matter in the reservoir as well as carbon entering the reservoir from upstream. Hydropower plants with power densities (installed power generation capacity divided by the flooded surface area) of greater than 4 W/m² but less than or equal to 10 W/m² have to consider project reservoir emissions to be 90 g CO_2 eq./kWh. Project reservoir emissions are considered negligible for projects with power densities greater than 10 W/m2[237, 238]. No approved methodology exists for hydropower projects with a power density of 4 W/m2 and less.

Leakage

No Leakage

The leakage of this project category is assumed to be zero. Emissions arising from power plant construction, fuel handling, and land inundation need not be taken into account.

Monitoring[239]

Data to be collected before Project Registration

Ex ante: Prior to the project validation, the following parameters must be collected for *ex-ante* emission reductions calculation. Plant emission factors used for the calculation of the OM and BM emission factors should be obtained according to the priority data sources given in ACM0002 (version 06)[240]:

Data for OM Calculation

- OM calculation: (i) Fuel consumption of each power plant in the PES by fuel type, (ii) CO_2 emission coefficient of fuels used by each power plant in the PES by fuel type, (iii) power generation of each power plant in the PES, (iv) fuel consumption in the CES by fuel type, (v) CO_2 emission coefficient of fuels used in the CES by fuel type, and (vi) power imports to the PES. Additional data is required for the following OM variations:
  - Dispatch data analysis: Merit order in which power plants are dispatched;

[236] These provisions are found in ACM0002 (version 06) but not in AMS-I.D (version 12). Since there has not been any application of AMS-I.D to geothermal power projects so far and AMS-I.D (version 12) does not mention on these emission sources from geothermal power projects, it is not clear at this stage whether small-scale geothermal projects also have to consider these project emission sources.

[237] See EB23, Annex 5.

[238] The power density concept is found in ACM0002 (version 06) but not in AMS-I.D (version 12). However, small-scale hydropower projects have also applied the project reservoir emissions based on the power density criterion since the EB23 decision. See for example the registered CDM project “831: Rialma Companhis Energétuca S/A”, available at: http://cdm.unfccc.int/Projects/DB/BVQI1167161981.54/view.html.

[239] As per the official CDM terminology, “monitoring” refers only to data collection requirements after the project implementation (i.e. ex-post). The ex-ante data collection requirements are included in this guide book to provide readers with a more comprehensive picture on overall data needs.

[240] These data should be obtained in the following priority: (i) acquired directly from the dispatch center or power producers, if available, or (ii) calculated, if data on fuel type, fuel emission factor, fuel input and power output can be obtained for each plant, or (iii) calculated as (ii), but using estimates such as default IPCC values, or (iv) calculated, for the simple OM and the average OM, using aggregated generation and fuel consumption data, in cases where more disaggregated data is not available (see page 5 of ACM0002 (version 06)). Examples of the application of aggregated data are described in Box 12 and 13.

– Simple adjusted OM: Fraction of time during which low-operating cost/must-run plants are on the margin;

Data for BM Calculation

- BM calculation: (i) Fuel consumption of capacity recently added to the PES by fuel type, (ii) CO2 emission coefficient of fuels used by capacity recently added to the PES by fuel type, (iii) power generation of capacity recently added to the PES. The items for power imports (i.e. items (iv) – (vi) for OM calculation) are necessary only if the recent additions (or likely future additions for *ex-post* BM calculation) to transmission capacity enable significant increases in power imports;
- Additional data is required for the following project types:
  - Retrofit projects: Annual power supplied to the PES prior to retrofit; and
  - Hydropower projects with construction of new reservoirs and/or enlargement of existing reservoirs: Surface area of the reservoirs at the full reservoir level.

Emissions of Geothermal Plants

Ex-post: After the project implementation, monitoring shall be conducted on the following items:

- Power generation of the project;
- Data required to recalculate the OM emission factor (if ex-post calculation is chosen);
- Data required to recalculate the BM emission factor (if ex-post calculation is chosen);

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- Additional data is required for geothermal power projects:
  - Fugitive emissions of CO2 and CH4 due to release of non-condensable gases from the produced steam: (i) average mass fraction of CO2 and CH4 in produced steam, and (ii) quantity of steam produced; and
  - CO2 emissions from operation of the geothermal power plant: (i) fuel consumption by fuel type, and (ii) CO_2 emission coefficient of fuels used by the project by fuel type.

5.2.4 AMS-I.D

Project Description

Project Types include Biopower

Similar to ACM0002, AMS-I.D covers a number of grid-connected renewable power generation technologies. The salient difference between AMS-I.D and ACM0002 technology coverage is that the former can be used for power generation from renewable biomass as well. Most of the existing AMS-I.D projects are biomass, biogas, wind, and hydro projects. There is only one solar PV project (registered) in this category. By September 2007, no tidal, wave, geothermal projects have been submitted based on AMS-I.D.

Applicability Conditions

Grid has to have at least one Fossil Power Plant

Interpretation of 15 MW Threshold

AMS-I.D (version 12) is applicable to grid-connected renewable power generation projects (e.g. PV, hydro, tidal, wave, wind, geothermal and renewable biomass) that supply power to and/or displace power from a power distribution system that is or would have been supplied by at least one fossil-fuel-fired generation unit. Combined heat and power systems are not eligible under this category. The eligibility limit of 15 MW for a small-scale CDM projects applies as follows:

Addition is counted separately

Retrofit cannot increase Capacity beyond Threshold

- If the units added have both renewable and non-renewable components, the capacity of the renewable component shall not exceed 15 MW;
- If the unit added is co-fired with fossil fuel, the capacity of the entire unit shall not exceed 15 MW;
- In the case of projects that involve the addition of renewable power generation units at an existing renewable power generation facility, the capacity of the added units by the project shall not exceed 15 MW; or
- In the case of projects that seek to retrofit or modify an existing renewable power generation facility, the total capacity of the modified or retrofitted unit shall not exceed 15 MW.

Box 19: Application of the 15 MW threshold for retrofit/ expansion projects

AMS-I.D originally stipulated that "to qualify as a small-scale CDM project activity, the aggregate installed capacity after adding the new units should be lower than 15 MW". Several requests were made to revise the applicability condition so that the 15 MW threshold applies to the power generation capacity added to the facility, but not to the aggregate capacity[241]. EB28 decided to revise AMS-I.D (version 09) to clarify that "in the case of project activities that involve the addition of renewable energy units at an existing renewable power generation facility, the added capacity of the units added by the project should be lower than 15 MW and should be physically distinct from the existing units."

PoA Bundling Applicability only for Biomass

Applicability conditions under a Programme of Activities (PoA): In case of a small-scale PoA where the limit of the entire PoA exceeds the limit for small-scale CDM project activities described above, the applicability of the methodology is limited to small-scale CDM Programme Activities (CPAs) that use either biomass residues only or biomass from dedicated plantations complying with the applicability conditions of AM 0042.

Project Boundary

Count CO_2 Emissions only, not other Gases

The spatial extent of the project encompasses the physical, geographical site of the renewable generation source. Within the project boundary, project participants shall only account for CO_2 emissions from fossil-fuel-fired power generation that is displaced due to the project. As explained above, additional emission sources are to be considered for hydropower and biomass power projects (and possibly geothermal power projects).

[241] See e.g. SSC_043, SSC_050.

Baseline Scenario and Additionality

Current Grid is Baseline Scenario

For a system where all generators exclusively use fuel oil and/or diesel fuel, the baseline scenario is diesel generation. Otherwise, the scenario is grid electricity generation

In both cases, additionality of the project shall be demonstrated by application of the barrier analysis, e.g. investment barrier, technological barrier, barrier due to prevailing practice, or other barrier[242]. If project participants wish, other additionality demonstration methods, e.g. the investment analysis stipulated in the additionality tool, can also be applied in addition to the barrier analysis. This is not a mandatory requirement, but has been applied to many small-scale projects of this category to strengthen their additionality argument.

Baseline Emissions

Diesel-fired Grid: Emission Factor of Diesel Generator

Choice among CM Calculation Methods, or Grid Average

Project Emissions are Zero

As compared to ACM0002, AMS-I.D provides methodological simplifications. The main simplification is that AMS-I.D allows for the discretional choice of the weighted average emissions factor of all plants serving the grid, which is much simpler than the CM approach. This factor is calculated *ex-post*; the data of the year in which project generation occurs must be used. Even if the CM approach is chosen, projects participants are allowed to use any of the four procedures to calculate the OM emission factor, as long as the criteria to use the simple OM and average OM methods are met. The application of default emission factors is also a key advantage for projects connected to diesel generator systems. Here, the annual power generated by the renewable unit is multiplied by an emission coefficient of a modern diesel generating unit of the same capacity operating at the optimal load. AMS-I.D provides default emission factors for three different diesel generator system categories operating at the optimal load.[243]

Project Emissions

With the exception of hydropower projects with power density less than or equal to 10 W/m^2 (see the project emissions section of ACM0002 above), the project emissions of this project category are assumed to be zero. It is not clear at this stage whether small-scale geothermal power projects have to consider the two project emission sources that need to be accounted for in the context of large-scale geothermal power projects.

[242] See Attachment A to Appendix B of the simplified modalities and procedures for small-scale CDM project activities.

[243] Category 1: Mini-grid with 24 hour service – 25% load factor; Category 2: (i) Mini-grid with temporary service (four-six hours/day), (ii) productive applications, and (iii) water pumps – 50% load factor; and Category 3: Mini-grid with storage – 100% load factor.

Leakage

Leakage: Transfer of Equipment

Biomass-related Leakage

Except for biomass power projects, leakage of this project category is assumed to be zero unless the project power generation equipment is transferred from another activity[244] or the equipment replaced is transferred to another activity[245]. Biomass power projects have to consider the following three sources of leakage[246]:

- **Shifts of pre-project activities:** Decreases of carbon stocks, for example as a result of deforestation, outside the land area where the biomass is grown, due to shifts of pre-project activities;
- **Emissions from biomass generation/ cultivation:** Potentially significant emission sources can be (i) emissions from application of fertilizer, and (ii) project emissions from clearance of lands; and
- **Competing use of biomass:** Biomass may be used elsewhere, for the same or a different purpose.

Leakage in PoA over 15 MW using SSC Methodology

Leakage under a PoA: Special attention should be paid to a small-scale PoA where the limit of the entire PoA exceeds the limit for small-scale CDM project activities, i.e. 15 MW power generation capacity. In such cases, the following leakage sources shall be taken into account:

Scrapping of Replaced Equipment

- In the case of a small-scale biomass PoA, leakage shall be determined following the general guidance for leakage in small-scale biomass project activities[247] or the procedures given in AM0042; and
- In the case of a small-scale PoA that involves the replacement of equipment, and the leakage effect of the use of the replaced equipment in another activity is neglected because the replaced equipment is scrapped, an independent monitoring of scrapping of the replaced equipment needs to be implemented.

Monitoring

Ex-ante Data for CM

Ex-ante: Prior to the project validation, the following parameters must be obtained for *ex-ante* emission reductions calculation:

- Data required to calculate the OM/ BM emission factor according to ACM0002 (if the option is chosen instead of the weighted average emission factor calculation); and
- Additional data is required for biomass power projects: A specific fuel consumption of each type of biomass and fossil (if any) fuel to be used.

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244 E.g. the CDM project could divert renewable power generation away from another activity by increasing demand for the renewable generation technology. In such a case, the activity might be forced to use fossil-fuel-fired generation technology instead. This would cause higher emissions for the activity than in the absence of the CDM project.

245 E.g. suppose the replaced equipment is transferred to an area where there is no power generation capacity, the transferred equipment would cause additional emissions from power generation in the area.

246 See EB28 "Indicative simplified baseline and monitoring methodologies for selected small-scale CDM project categories – General guidance on leakage in biomass project activities (Version 02)".

247 See Attachment C to Appendix B of the simplified modalities and procedures for small-scale CDM project activities.

Ex-post Data on Power Generation

Ex-post: After the project implementation, monitoring shall be conducted on the following items:

- Power generation of the renewable component of the project. If fossil fuel is used in the project, the power generation metered should be adjusted to deduct power generation from fossil fuels using the specific fuel consumption and the quantity of fossil fuel consumed;
- Weighted average emission factor (if the option is chosen instead of CM calculation): The same data requirements as the average OM of ACM0002. But the data of the year in which project generation occurs must be used;
- Data required to recalculate the OM emission factor (if *ex-post* calculation is chosen);
- Data required to recalculate the BM emission factor (if *ex-post* calculation is chosen); and
- Additional data is required for biomass power projects: The amount of biomass and fossil (if any) fuel input shall be monitored by fuel type.

Monitoring under a PoA:

- Number of the distributed and scrapped equipment; and
- Additional data is required for biomass power projects following the general guidance for leakage in small-scale biomass project activities or the procedures given in AM0042.

5.2.4 AM0029

Project Description

Greenfield Gas Power Plants

AM0029 is a methodology for greenfield natural-gas-fired grid-connected power generation projects. After the methodology approval in May 2006, AM0029 has been repeatedly applied. By September 2007, the number of AM0029 projects reached 25, most of which were estimated to generate a large amount of CERs (500 – 3,200 kt CO_2 p.a.). All these projects were based in China and India.

Applicability Conditions

Need for sufficient Gas Availability

AM0029 (version 1) is applicable to projects that construct and operate a new natural-gas-fired grid-connected power generation plant. The geographic/ physical boundaries of the baseline grid shall be clearly identified and information pertaining to the grid and estimating baseline emissions must be publicly available. In addition, natural gas must be sufficiently available in the region or country.

Gas Supply has to be sufficient throughout the Crediting Period

Box 20: Sufficient natural gas supply in the future

A project attempted to deviate from the AM0029 applicability condition on natural gas availability because the project did not meet the condition due to the delay in production of gas blocks within the region[248].The project power plant started its commercial operation in 2002. Although the project was in natural gas supply deficit and consequently operating at a lower load factor at the time of request for deviation in 2007, it argued that the upcoming gas blocks would lead to sufficient gas availability in the region by 2008 (confirmed by the DOE). The EB decided not to accept the request because the project did not meet the applicability condition at the time of validation – natural gas shall be sufficiently available during the entire crediting period(s).

Project Boundary

Grid defines Project Boundary

The spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid as defined in ACM0002.

Only CO_2 emissions taken into Account

In calculation of project emissions, only CO_2 emissions from fossil fuel combustion at the project plant are considered. In calculation of baseline emissions, only CO_2 emissions from fossil fuel combustion in power plant(s) in the baseline are considered.

Baseline Scenario and Additionality

The most plausible baseline scenario shall be selected based on the following two-step analysis: (i) identification of alternative baseline scenarios, and (ii) identification of the economically most attractive baseline scenario alternative.

All Power Plant Technologies built or under Construction are Baseline Scenario Candidates

The identification of alternative baseline scenarios should include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project, i.e., all types of power plants that could be constructed as alternative to the project within the grid boundary (as defined in ACM0002), such as different technologies using natural gas, power plants using other fuels or power import from connected grids, including the possibility of new interconnections. The alternatives need not consist solely of power plants of the same capacity, load factor and operational characteristics but should deliver similar types of services (e.g. peak vs. baseload power). All relevant power plant technologies that have recently been constructed, or are under construction, or are being planned have to be covered, including those available to other stakeholders within the grid boundary. Alternatives that are not in compliance with all applicable legal and regulatory requirements can be excluded.

[248] See 'Deviation for not meeting one of the applicability clauses of methodology "Natural gas is sufficiently available in the region and country"', available at: http://cdm.unfccc.int/UserManagement/FileStorage/T8IHJUQB1L2IPOPY8FPGBUV34Y1XVV.

Investment Comparison for all Scenarios on Basis of Levelized Costs

Once all scenarios have been identified, the economically most attractive baseline scenario alternative is chosen using investment analysis. The levelized cost of electricity production in $/kWh should be used as an indicator for investment analysis[249]. Project participants shall include all relevant (i) costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), (ii) revenues (including subsidies/fiscal incentives, ODA, etc. where applicable), including non-market cost and benefits in the case of public investors.

Sensitivity Analysis required

A sensitivity analysis shall be performed for all alternatives to confirm that the conclusion regarding the financial and/or economical attractiveness is robust to reasonable variations[250] in the critical assumptions (e.g. fuel prices and a load factor). The investment analysis provides a valid argument only if the sensitivity analysis consistently supports the conclusion. In case the sensitivity analysis is not fully conclusive, select the baseline scenario alternative with the lowest emission rate among the alternatives that are the most financially and/or economically attractive. If the emission rate of the selected baseline scenario is clearly below that of the project activity,[251] then the project activity should not be considered to yield emission reductions, and this methodology cannot be applied.

Upon establishment of the most plausible baseline scenario, additionality of the project shall be demonstrated based on the following three steps: (i) benchmark investment analysis, (ii) common practice analysis, and (iii) impact of CDM registration.

Additionality Test repeats Investment Analysis

Step 1 – Benchmark investment analysis: Demonstrate that that the proposed CDM project activity is unlikely to be financially or economically attractive by applying benchmark analysis, calculation and comparison of financial indicators), and sensitivity analysis as specified in the latest version of the additionality tool. With the current version of the additionality tool (version 03), this is essentially the same procedure as step 2 of the baseline scenario identification procedure described above.

Common Practice Test

Step 2 – Common practice analysis: Demonstrate that the project activity is not common practice in the relevant country and sector

Impact of CDM Scenario Registration Test

Step 3 – Impact of CDM registration: Describe the impact of the registration of the project activity.

If all the three steps are satisfied, then the project is considered additional.

Baseline Emissions

Lowest of three Emissions Factors: BM, CM or Emissions Factor of Baseline Formula for Emissions Factor of Baseline Scenario

The baseline emissions are calculated by multiplying the power generated by the project plant by a baseline emission factor. The baseline emission factor is estimated as the lowest emission factor among the following three options:

- Option 1: The BM emission factor, calculated according to ACM0002;
- Options 2: The CM emission factor, calculated according to ACM0002 with 50%/50% OM/BM weights; and

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249 In calculating the indicator, risks of the alternatives can be included through the cash flow pattern, subject to project-specific expectations and assumptions (e.g. insurance premiums can be listed in the calculation to reflect specific risk equivalents).

250 Typically, a range between -10% and +10% is applied.

251 E.g. the baseline scenario is hydro, nuclear or biomass power.

- Option 3: The emission factor of the technology (and fuel) identified as the most plausible baseline scenario, calculated as follows:

$(tCO_2/MWh)_{baseline}$	=	$(tCO_2/GJ)_{baseline}$	/	$\eta_{baseline}$	X	3.6 (GJ/MWh)
Baseline Emissions per Unit Power		Fuel Emission Coefficient		Energy Efficiency of the Technology (in Fraction)		Conversion Factor from MWh to GJ

Note: The fuel emission coefficient should be based on national average fuel data, if available. Otherwise, the IPCC default values can be used.

Choice repeated at each Update of Crediting Period

The baseline emission factor determination will be made once at the validation stage based on an *ex-ante* assessment for the first crediting period and once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated *ex-post*, as described in ACM0002.

Project Emissions

Project Emissions: Fuel burned by Project

The project activity is on-site combustion of fossil fuel (mainly natural gas) to generation power. Therefore, the project emissions are calculated as the product of the amount of fossil fuel consumption and the CO_2 emissions coefficient of the corresponding fossil fuel.

Leakage

Leakage: Lifecycle Emissions of Fuel used

Project participants shall consider the following sources of leakage when applying the methodology:

- "Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant" minus "fugitive CH_4 emissions from fossil fuels (e.g. coal or oil type)[252] used in the grid in the absence of the project activity"; and
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/ power consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Emissions factors used should be derived from reliable and accurate national data; if those are not available, default values for different regions can be used. Where total net leakage effects are negative, project participants should assume the leakage as zero.

[252] The upstream fugitive CH4 emissions of coal power generation depend on the coal source (i.e. underground or surface mines). In case of oil power generation, the upstream fugitive CH4 emissions should include oil production, transport, refining, and storage.

Monitoring

Ex-ante Monitoring:

Ex-ante: Prior to the project validation, the following parameters must be collected for *ex-ante* emission reductions calculation. The following plant emission factors used for the calculation of the OM and BM emission factors should be obtained on the basis of the ranking of data sources given in ACM0002 (version 06):

- Data required to recalculate the BM emission factor (if option 1 is chosen for the baseline emission factor calculation);
- Data required to recalculate the OM emission factor (if option 2 is chosen for the baseline emission factor calculation);
- CO_2 emission coefficient of fuels used by the identified baseline scenario by fuel type (if option 3 is chosen for the baseline emission factor calculation);
- Energy efficiency of the technology used in the identified baseline scenario (if option 3 is chosen for the baseline emission factor calculation); and

Gas Availability

- Availability of natural gas in the project region.

Ex-post monitoring

Ex-post: After the project implementation, monitoring shall be conducted on the following items:

- Data required to recalculate the OM emission factor (if *ex-post* calculation is chosen);
- Data required to recalculate the BM emission factor (if *ex-post* calculation is chosen);
- Power generation of the project;
- Fuel consumption of the project by fuel type;
- CO_2 emission coefficient of fuels used by the project by fuel type;
- Emission factor for upstream fugitive CH_4 emissions of natural gas combusted by the project;
- Emission factor for upstream fugitive CH_4 emissions occurring in the identified baseline scenario; and
- Emission factor for upstream CO_2 emissions due to fossil fuel combustion/ power consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system (only if the project uses LNG).

Industrial Gas Methodologies

5.3 Decomposition of industrial gases HFC-23 and N_2O

5.3.1 Methodologies analyzed

Large Scale	AM0001 (version 5) "Incineration of HFC waste streams"
Large Scale	AM0021 (version 1) "Baseline methodology for decomposition of N2O emissions from existing adipic acid production plants"
Large Scale	AM0034 (version 2) "Catalytic reduction of N2O inside the burner of nitric acid plants"

5.3.2 Basic concept

Chemical Production releases strong Greenhouse Gases

All three methodologies deal with the "end-of-pipe" decomposition of industrial gases HFC-23 (Fluoroform) or N_2O (Nitrous oxide). The gases are un-wanted by-products from production plants of the chemical industry and have a very high Global Warming Potential (1t N_2O = 310 t CO_2 eq. and HFC-23 = 11,700 t CO_2 eq.). This makes decomposition of such gases the most attractive CDM projects in the market with costs of CER generation ranging from 0.1 – 0.5 €/CER.

Emissions Reduction through thermal Decomposition

All three methodologies assume that in the absence of the CDM project, HFC-23/ N_2O emissions would have been released to the atmosphere via the stack of the plant. Therefore, the common and most important rationale of the methodologies is that emission reductions are the difference between the emissions of the gas from the plant before (baseline emissions) and after implementation of the decomposition facility (project emissions) and adjusted for potential indirect emissions due to the project.

ER_y	=	$EF_{bl,y}$	X	$Prod_{bl,y}$	X	GWP	-	PE_y	-	$Leakage$
Emission Reductions		Emission factor of baseline		Baseline amount of industrial gas production		Global warming potential of industrial gas		Direct emissions of the project (e.g. fuel combustion or industrial gas still released)		Indirect emissions due to the project

Basel

Methodologies only applicable for existing Capacity

Baseline emissions (expressed in HFC-23 or N_2O) are determined by multiplying a historic emission factor (t HFC-23 or t N_2O/ per t of HCFC-22 or adipic acid or nitric acid produced) with the amount of production of the chemical product after installation of the destruction facility. The plant output eligible for calculation of baseline emissions is capped at historic production levels to ensure the environmental integrity of such CDM projects. For the same reason, greenfield chemical production plants are not allowed to use the approved methodologies (see Box 21).

Perverse Incentives for new Capacity?

HFC-23 Revenues allow to increase Production of HCFC-22

Only pre-2005 Plants eligible to use AM 0001

Box 21: The debate on "perverse incentives" from HFC production under CDM and its implications

The first methodology approval ever was made by the EB for AM0001 in July 2003 (EB 10). A few months after its approval and following a workshop organized in China on this topic, the EB was requested in a non-paper by Othmar Schwank, leader of the international team of experts under the CDM National Strategy Study for China, to reconsider its approval of AM0001 due to its adverse impact on the environmental integrity of the CDM. The non-paper concluded that due to the low cost of HFC decomposition and the high revenues from CER sales, the approval of the methodology will cause a flood of project registrations and bring down HCFC-22 prices in developing countries. As HCFC-22 is harmful to the ozone layer (and itself a GHG not covered under the Kyoto Protocol), AM0001 creates a "perverse incentive" to keep up production levels of HCFC-22 in developing countries while, according to the Montreal Protocol, these countries are mandated to phase out HCFC-22 by latest 2040. As a reaction the EB put the methodology "on hold" in September 2004[253] and requested the MP to again review the methodology. The MP followed suit and launched a call for public inputs on the topic (MP 12). The call triggered a stream of submissions from different interest groups (NGOs to project developers). The main finding from the call was that AM0001 might, due to the cheap CER generation, provide an incentive to only produce HCFC-22 for the sake of destroying HFC-23 – without actually selling the HCFC-22. The EB finally approved AM0001 again in May 2005 but limited its applicability to HFC production plants that existed before 31.12.2004 and that have an operating history of at least three years in the period from 2000 to 2004. The consequence is that so far no plant built after 31.12.2004 is allowed to use AM0001. The COP/MOP as its Bali meeting (COP12) has been asked to prepare guidance to the EB on how to deal with new capacity.

Additionally, emission reductions were capped by limiting the plant output eligible for calculation of baseline emissions to the lower production of a) the actual production of the plant during CDM project operation, or b) the maximum historic production in any of the last three years between 2000 and 2004. The capping was introduced in order to prevent plants under CDM producing more HCFC-22 than they can sell for the sole purpose of CER generation.

The lessons-learnt from the debate on HFC projects have been later on been applied to AM0021 and AM0034 where only existing production plants are eligible to use the methodologies and production eligible for determination of baseline emissions are capped at existing production capacity.

Baseline emissions are also automatically adjusted during CDM project operation once the host country introduces a regulation that mandates a certain absolute or relative level of emissions. In this case baseline emissions are at a maximum the level of emissions that the regulation allows. This goes contrary to the decision by the EB to not consider policies or regulations that limit GHG emissions that have been introduced after the Marrakech Accords (2001) in the baseline (see section 4.1.2). One can therefore expect to see requests for deviations from AM0001, AM0021 and AM0034, if regulations in host countries should be tightened, arguing on the basis of the EB 22 decision that the baseline does not need to be adjusted.

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[219] EB 15, para 12

No Additionality Problem

Another common feature of projects using the three methodologies is that additionality is undisputed and no request for review has ever been launched on any of the registered projects on additionality grounds. The projects do (almost) not create any revenue in the absence of the CDM[220].

5.3.1 AM0001

Project description

HCFC-22 produces HFC-23 as Byproduct

HFC-23 originates from the production of Chlorodifluoromethane (HCFC-22) which is used as a refrigerant and as a feedstock for the production of PTFE (Polytetrafluoroethylene also known as Teflon).

In CDM projects using AM0001, the HFC-23 is prevented from entering the atmosphere by oxidization of the HFC-23 gas at very high temperatures in an incineration furnace before the stack.

Host Country Regulation on HFC Destruction determines Baseline

In the absence of any regulations HFC-23 is typically released to the atmosphere as it does not make economic sense to capture it. The amount of HFC-23 produced during the manufacture of HCFC-22 depends on two factors: the way the process is operated and the level of process optimization. Generally, the bandwith of HFC-23 emissions is on the order of 1.5 to 3 % of the HCFC-22 production. According to IPCC estimates, a reasonable average estimate is 2% (IPCC 2000). According to the methodology, the emission reductions are therefore the quantity of gas destroyed in the CDM project minus the emissions from the decomposition facility minus leakage.

The project will usually require the installation of a HFC-23 waste gas collection facility, a storage facility (to buffer HFC-23 from the HCFC-22 production process), an incinerator (in most of the cases this will be natural gas-fired device), a cooling tower and a neutralization pond. The decomposition facility will produce a sludge that will need to be landfilled.

Applicability conditions

Only pre-2005 Plants with 3 Years of Operation before 2005 are eligible

In the CDM projects using AM0001, an incinerator needs to be used to convert the carbon in the HFC-23 to CO2 which is then released through the stack of the plant. Production plants that started operation after 31.12.2004 are not eligible to use AM0001 (see Box 17). The plant additionally needs to have an operating history of at least three years between beginning of the year 2000 and the end of the year 2004 and has been operated from the start of 2005 until the start of the CDM project. In case the host country requires the destruction of all the HFC-23 waste gas generated AM0001 cannot be used. Offsite transport from the HCFC-22 production plant to another site is not allowed under the methodology (see Box 22)

No Destruction in an Another Country

> **Box 22:** Destruction of HFC in another country
>
> The Mexican "Quimobásicos HFC Recovery and Decomposition Project" (UNFCCC no. 0151) initially planned to destroy HFC-23 in an existing decomposition plant in the U.S. However, the EB decided that this is not covered under AM 0001[255]. The project developers therefore built the decomposition plant on their site.

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[220] Thermal decomposition projects can technically generate heat that might be used to generate steam for on-site use.

[221] EB 22, para 27

Project Boundary only Decomposition Facility

Project boundary

The project boundary includes the HCFC-22 production facility and the HFC-23 destruction facility. Transportation of the sludge originating from the neutralization pond is outside of the project boundary. The same applies to the production of purchased energy (electricity and/or steam) used for the operation of the decomposition facility.

Baseline scenario and additionality

The baseline scenario is continuation of the practice to release HFC-23 waste gases to the atmosphere taking into account current regulatory requirements. The project is additional, if the amount of gas destruction in the project is higher than the amount that currently needs to be decomposed due to existing legislation. This means that in the absence of any regulation, any project is automatically additional.

Baseline emissions

Calculation of baseline emissions follows a step-wise approach. In a first step, the maximum amount of HCFC-22 production eligible for calculation of baseline emissions is determined (see Box 23) and multiplied with the historic HFC-23 emission factor from the plant (in t HFC-23/ t HCFC-22).

Determination of HCFC-22 maximum Production Capacity

> **Box 23:** Determination of maximum production capacity in case of multiple production lines and swing plants
>
> Following a request for clarification from a company that had recently bought up a neighboring HFC-23 production plant next to their initial plant, the EB generally decided that the historical level of production should be established for all production lines at a single industrial site. This decision avoids that the maximum eligible production can be significantly higher than the actual production of the respective plant.
>
> At some plants HFC-23 can also be produced on the same lines as the chlorofluorocarbons CFC-11 and CFC-12. In such "swing plants" the CFC production must be included as equivalent HCFC-22 production based on historic HCFC-22 and CFC production capacity. If historic records are available, the project proponent needs to measure the production capacity of each gas separately at the plant at full load to arrive at the total maximum eligible HCFC-22 production.

Cap on Emission Factor

In analogy to the procedure for determination of the eligible HCFC-22 production, the historic emission factor has to be the lowest of the historic annual emission factor of the three most recent years of operation up to 2004. The emission factor is fixed for the entire crediting period(s) and is capped at 3%. The emission factor must be estimated based on historic process data (see Box 24). If data should be insufficient to determine the historic emission factor, a default value of 1.5% must be used.

Measurement of Historic Emissions Factor

> **Box 24:** Challenges in estimation of historic emission factor
>
> Direct measurement of HFC-23 release is the preferred method of establishing the historic emission factor. In cases where such data is not available the project proponents are allowed to use mass balance or alternative methods based on actual data. The first registered CDM project, a HFC-23 destruction project in Gujarat (India), for example used a chloroform mass balance to derive the emission factor. This has been accepted by the validating DOE and the project proponent was allowed to use the emission factor of 2.9% instead of having to use the much more unfavorable default of 1.5%.

In a second step, it is tested whether the baseline emissions resulting from Step 1 are larger than those resulting from the amount of waste gas that would be required to be destroyed by regulation. If this is the case, the HCFC-22 production quantity eligible for calculation of baseline emissions is capped at the level as required by the relevant regulation.

Project emissions

HFC-23 not destroyed

The only sources of GHG emissions in the project boundary result from amounts of HFC-23 not destroyed and CO_2 emissions from the fuel used during combustion.

Leakage

Energy from External Sources and Transport Emissions

Steam and power consumption are accounted for as leakage as these forms of energy are usually purchased from external sources and associated GHG emissions are therefore not included in the project boundary. CO_2 emissions due to fuel combustion for transportation of the sludge are also leakage emissions.

Monitoring

Monitoring shall be conducted on the following items:

Ex ante

- HCFC-22 production and HFC-23 release from 2001-2004
- Last years HCFC-22, CFC-11 and CFC-12 production records
- Regulation on HFC-23 emission threshold, if any

Ex post

- Amount of HFC-23 supplied to the destruction process (see Box 21)
- Amount of HFC-23 generated in each production line
- Purity of HFC-23
- Potential leakage of HFC-23 emissions from the thermal oxidizer during shut-down times
- Quantity of HCFC-22 produced and sold
- Fossil fuels burned in the project and their emission factors differentiated according to fuel type
- Electricity grid emission factor according to ACM 0002
- Electricity consumption
- Steam consumption and steam emission factor of the steam source

AM0001: Most stringent Requirements on Data Accuracy

Box 25: Ensuring accuracy of measurements in HFC-23 projects

AM0001 has one of the most stringent requirements of all approved methodologies in terms of data accuracy. It is the only methodology where two flow meters need to be used to measure the same parameter – in this case the amount of HFC-23 generated (HFC-23 flow) – and where the lower of the two values need to be used. Additionally, the methodology asks the project proponent to weekly perform a functionality check of the flow meters and to calibrate the meters every six months.

5.3.2 AM0021

Project description

Thermal Decomposition more attractive than Catalytic Reduction

Adipic acid serves as a feedstock in polymer (mostly nylon) production. As a by-product of adipic acid production N_2O occurs and is typically released into the atmosphere in the absence of any regulation. In principal two proven technological options exist to prevent the release of N_2O emissions: decomposition during thermal destruction or catalytic reduction. So far, thermal destruction is the preferred and only choice of CDM project developers because it entails lower total costs and has a higher efficiency (decomposition rate of > 99%). A CDM project based on thermal destruction technology will involve the thermal combustion unit fired by natural gas and a steam boiler to heat exchange the enormous amounts of heat from the process to usable steam. The flue gas will be released through the stack and will usually be treated by a DENOx facility which removes the nitrous oxide from the gas.

Applicability conditions

Only pre-2005 Plants

The methodology is applicable to both thermal destruction as well as catalytic reduction of the N_2O. Only such adipic acid plants are eligible that have been in operation before 2004.

Project boundary

The project boundary entails the adipic acid production plant and the decomposition facility.

Baseline scenario and additionality

Continuation of Status Quo

The baseline scenario is continued venting of the N_2O to the atmosphere taking into current regulatory requirements. The additionality test prescribed by the methodology requires the project proponent to demonstrate that a) he is not mandated by any regulation to reduce his emissions, b) N_2O abatement is not common practice in his sector and region of production and c) that the project would not be viable without CDM.

Baseline emissions

Baseline emissions consist of the amount of N_2O emissions that would have continued to be released plus CO_2 emissions resulting from the amount of steam that in the absence of the project would have been generated by combustion of fossil fuels. As the latter part is by far the smaller part of baseline emissions (less than 0.01%), only the N_2O emissions baseline is discussed in the following.

Determination of the Emission Factor

The N_2O emissions baseline is the amount of adipic acid produced during project operation multiplied with an N_2O emission factor per output of adipic acid. The emission factor needs to be calculated based on the chemical consumption of nitric acid according to the following formula:

N_2O/AdOH	=	*HNO3_chem*	/	*P_AdOH*	/	*63/2 x 0.96 x 44*
N_2O emission factor		Chemical consumption of nitric acid		Adipic acid production		Ratio of N_2O to N_2

Cap of Emission Factor

For reasons of conservativeness, the emission factor is capped at 0.27 kg N_2O/ kg of AdOH which is the lower value given by the IPCC Good Practice Guidance.

Emissions caused by remaining N_2O Emissions and Fuel Combustion

Project emissions

The sources of GHG emissions of the project are N_2O that has been by-passing the decomposition facility or not decomposed within the facility and CO_2 emissions due to combustion of natural gas in the facility.

Leakage

As in the case of AM0001, steam and power consumption are accounted for as leakage as these forms of energy are usually purchased from external sources and associated GHG emissions are therefore not included in the project boundary.

Monitoring

Monitoring shall be conducted on the following items:

Ex ante

- Regulations on N_2O emission threshold, if any

Ex post

Main monitoring Activities: Flow of N_2O and fossil Fuel Use

- Amount of adipic acid production (see Box 23)
- Amount of N_2O supplied to the destruction process
- Amount of N_2O by-passing the destruction process
- Amount of N_2O generated in the adipic acid facility
- Flow of effluent gas from the destruction facility
- Concentration of N_2O in the effluent gas
- Regulations on N_2O emission threshold, if any
- Fossil fuels burned in the project and their emission factors differentiated according to fuel type
- Electricity grid emission factor according to ACM 0002
- Steam consumption and steam emission factor
- Electricity consumption

Debate on required Level of Detail of adipic Acid Production Calculation

Box 26: Request for review of CER issuance due to unclear amount of adipic acid produced

The EB launched a request for review of issuance for one of the two registered AM0021 projects as it felt that the calculation of the adipic acid production was not transparent and should be reproducable for the reader of the monitoring report. As a response the verifying DOE sent a 2 page-description of the method for calculation with the remark that the process of calculation is very complex and that the underlying data is stored and processed on SAP systems and other databases of the adipic acid plant. The DOE continued saying that a secondary check of the calculations by the RIT or EB would require sending a 10 MB file of which checking would require a few man-days of someone who is familiar with the subject. This argumentation was accepted and the CERs were issued subsequently.

5.3.3 AM0034

Project description

Emission Reduction Options in Nitric Acid Production

Applicability limited to secondary catalytic Reduction

N_2O in nitric acid production is a by-product of the high temperature catalytic oxidation of ammonia (NH_3). The N_2O is normally vented into the atmosphere. The N_2O concentration in the tail gas depends on the pressure under which the nitric acid is produced. The emission factor can vary from 5 kg N_2O/t nitric acid (+/- 10%) for atmospheric pressure plants to 9 kg N_2O/t nitric acid (+/- 40%) at high pressure plants (>8 bar). N_2O emission reduction in nitric acid plants happens through the installation of a dedicated N_2O abatement catalyst inside of the ammonia burner of the nitric acid plant. Currently, two technically proven N_2O abatement technologies exist. The first one is know as secondary catalytic reduction where N_2O is removed in the burner after the ammonia oxidation gauzes. These are the abatement project types AM0034 has been designed for. The second option is known as tertiary abatement where N_2O is removed from the tail gas. Tertiary abatement itself can be classified in non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR). The former option is used for reducing the local pollutant NO_x from nitric acid manufacturing but also partly reduces N_2O emissions. Generally speaking secondary abatement achieves higher N_2O reduction at lower costs.

Secondary catalytic reduction requires the installation of a dedicated N_2O catalyst in the ammonia burner and a complete N_2O monitoring system including both a gas volume flow meter and an infrared analyzer.

Applicability conditions

Plants built from 1st January 2006 onwards not eligible

The methodology is applicable to nitric acid plants that have been built before 1st January 2006 and where the host country does not mandate any reduction in N_2O emissions. For plants where any N_2O abatement technology (including a non-selective catalytic reduction unit) is operating the methodology is not applicable.

Project boundary

The project boundary encompasses all units and facilities required for the nitric acid production process from the inlet to the stack.

Baseline scenario and additionality

The methodology is the only methodology that refers to another approved methodology (AM0028) for identification of the baseline scenario. AM0028 is applicable for tertiary N_2O abatement only, however the baseline alternatives are the same for both secondary and tertiary abatement. Baseline scenario identification follows a step-wise approach.

Financially most attractive Option to reduce N_2O Emissions and/or NO_x Emissions is the Baseline Scenario

In a first step, all technological options that reduce N_2O emissions as well as NO_X emissions (as long as they impact N_2O emissions at the same time) need to be considered as potential baseline scenarios. A non-exclusive list of such options includes (i) the continuation of venting of all N_2O, (ii) alternative use of N_2O (e.g. recycling and use as a feedstock), (iii) installation of a (new) Non-Selective Catalytic Reduction (NSCR) unit, (iv) installation of an N_2O destruction or abatement technology (e.g. primary, secondary or tertiary) and (v) installation of a new tertiary measure that combines NO_X and N_2O emission reduction.

Subsequently, all baseline alternatives have to be eliminated that do not comply with the legal and regulatory requirements on N_2O and NO_X emissions. If an option is in theory mandated but not enforced, non-enforcement needs to be demonstrated for the alternative to be considered a possible baseline scenario.

In a third step a barrier test needs to be performed for all alternatives (e.g. investment or technological barrier).

Finally, an investment analysis shall be undertaken for all remaining alternatives and the alternative which is financially most attractive is the baseline scenario.

Baseline emissions

Baseline Emission is Output times N_2O Emission Factor

Baseline Campaign as the Basis for Emission Factor Determination

As in the absence of the project the N_2O would have been vented, the N_2O emissions baseline is the amount of nitric acid produced during project operation multiplied with an N_2O emission factor per output of nitric acid. The emission factor is calculated based on measurements of N_2O emissions during a so called baseline campaign. In nitric acid manufacturing a campaign is a discrete production run which lasts from a new set of primary catalyst gauze until the gauze is decomposed and is exchanged by new gauze. The baseline campaign refers to a single full campaign at similar operating conditions as the last previous five campaigns (see monitoring section below) at which the N_2O emissions are measured. The amount of N_2O emissions over the length of the campaign is calculated according to the following formula:

BE_{BC}	=	VSG_{BC}	x	$NCSG_{BC}$	x	10^{-9}	x	OH_{BC}
Baseline N2O emissions		Mean gas volume flow rate		Mean concentration of N2O in stack gas per hour				Operating hours of the baseline campaign

The emission factor is subsequently calculated according to the following formula:

EF_{BL}	=	$(BE_{BC}$	/	$NAP_{BC})$	x	$(1-UNC/100)$
N2O baseline emission factor		Baseline N2O emissions		Nitric acid production		Adjustment factor for the overall uncertainty of the monitoring system

Baseline Campaign should be representative to avoid Gaming

If the plant during the baseline campaign operates outside of the permitted range of operating conditions measured for the previous five campaigns (see monitoring section below), the baseline campaign has to be repeated.

Project emissions

Project Emissions are determined as for Baseline Emissions

Moving average Project Emission Factor for Precision

Project emission calculation is based on production campaigns as well and follows exactly the same rationale as baseline emission calculation. The nitric acid production during each campaign during project operation is multiplied with the N_2O emission factor derived for this particular campaign (as described for the establishment of the baseline emission factor) in order to determine the N_2O project emissions. However, the project N_2O emission factor has to be a moving average emission factor in order to allow for a more representative and precious determination. The moving average emission factor is calculated as follows:

$EF_{ma,n}$	=	$(EF_1$	+	EF_2	+…+	EF_n	/	n
Moving average baseline emission factor		Emission factor of project campaign 1		Emission factor of project campaign 2		Emission factor of project campaign n		Total number of project campaigns

Leakage

No Leakage

No leakage calculation is required as the installation of the N_2O abatement catalyst does not cause any GHG emissions outside of the project boundary.

Monitoring

AM0034 requires the most complex and most costly monitoring of all project types registered so far under CDM (see Box 27).

Most complex Monitoring Procedure in CDM

Box 27: **Ensuring accuracy of measurements in secondary catalytic N_2O abatement projects**

AM0034 requires the utilization of the use of the European Norm EN 14181 "Quality assurance for automated measuring systems". Simply speaking the norm specifies a number of tests/calibrations that need to be performed on the monitoring equipment for N_2O concentration measurements in order to ensure data accuracy to the highest standard possible. First of all, EN 14181 requires the monitoring instruments to be used not to exceed pre-defined uncertainty ranges. If equipment fails the test, it may not be usable for baseline and project campaign measurements. This has led to the situation where project proponents needed to revise parts of their monitoring system installed in the process in order to comply with EN 14181. During the baseline campaign the installed measurement equipment needs to be calibrated with the so called "Standard Reference Method" by an independent testing laboratory to ensure reliable results of monitoring. This also needs to be done during the first project campaign. During project operation the monitoring system is subject to on-going quality assurance (to be performed continuously by the plant owner) and annual surveillance test (to be performed annually by an independent testing laboratory).

Monitoring shall be conducted on the following items:

Ex ante

The following data needs to be gathered for the previous five complete campaigns before request for registration:

- Oxidation temperature and pressure and its normal range
- Ammonia to gas flow rates and ammonia to air ratio in the reactor
- Gauze supplier and composition
- Normal campaign length
- Regulations on N_2O emission threshold, if any

Baseline Data Requirements

The following data needs to be gathered during the baseline campaign (see Box 28 for timing of baseline campaign):

- N_2O concentration in the stack gas
- Volume flow rate of the stack gas
- Length of the baseline campaign
- Nitric acid production
- Oxidation temperature and pressure and its normal range
- Ammonia to gas flow rates and ammonia to air ration in the reactor
- Overall uncertainty of the monitoring system (combined uncertainty of all monitoring equipment)
- Gauze supplier and composition

Baseline Emission Factor can be determined and fixed *after* Project Registration

> **Box 28:** Determination of baseline emission factor after project registration
>
> With any methodology other than AM0034 baseline emission factors that are fixed throughout the crediting period need to be established before registration. Projects using AM0034 are so far the only projects where the baseline emission factor can be established by measurements after the project registration and is then fixed. This development has been triggered by project proponents that lobbied for this approach. The idea was to achieve registration before the end of the baseline campaign (which can take from 3-6 months) and have early investment certainty. The DOE can then verify the baseline campaign results during initial or first verification.

Ex post

- N_2O concentration in the stack gas
- Volume flow rate of the stack gas
- Pressure of the stack gas
- Temperature of the stack gas
- Length of the baseline campaign
- Nitric acid production
- Oxidation temperature and pressure and its normal range
- Campaign length
- Ammonia to gas flow rates and ammonia to air ration in the reactor
- Overall uncertainty of the monitoring system (combined uncertainty of all monitoring equipment)
- Gauze supplier and composition
- Regulations on N_2O emission threshold, if any

5.4 Energy efficiency

5.4.1 Methodologies analyzed

Large Scale	ACM 0012 (version 1) "Consolidated baseline methodology for GHG emission reductions for waste gas or waste heat or waste pressure based energy system"
Large Scale	ACM 0004 (version 2) "Consolidated baseline methodology for waste gas and/or heat and/or pressure for power generation" (withdrawn)
Large Scale	AM 0046 (version 1) "Distribution of efficient light bulbs to households"
Small Scale	AMS-II.D (version 10) "Energy efficiency and fuel switching measures for industrial facilities"

5.4.2 Basic concept

Emissions Reductions: Energy Savings times Emissions Factor of Energy

Emission reductions are calculated as the difference between the energy use of the existing equipment and the project multiplied by the emission factor of the energy type used (tCO_2/MWh), which in the case of electricity is usually a combined margin derived from the methodologies for renewable grid electricity (see Chapter 5.2).

ER_y	=	$EF_{bl,y}$	X	$(MWh_{bl,y}$	-	$MWh_{pj,y})$	-	*Leakage*
Emission Reductions		Emission factor of baseline		Energy saved/ generated by the project		Electricity saved/ generated by the project		Indirect emissions

5.4.3 ACM0012

ACM 0012 was introduced by EB 32 and consolidates ACM 0004 and AM 0032. It has not yet been applied as project developers continue to use ACM 0004 in the 8-month grace period that lasts until April 2008.

Description of the current version of the methodology

Waste Gas, Waste Heat and Waste Pressure can be used

Energy can be exported, but User is not allowed to claim CERs

Applicability conditions: ACM0012 is applicable to utilization of waste gas and/or waste heat as an energy source for cogeneration (excluding combined cycle plants), electricity generation, process heat or generation of heat utilized in equipment at one point of an industrial facility as well as utilization of waste pressure for electricity generation. Energy can be used within the industrial facility or exported. The project can be implemented by the owner of the industrial facility or a third party. Both greenfield and retrofit projects are possible; capacity expansions are treated like greenfield projects. Crediting period is limited to remaining lifetime of retrofitted equipment. It has to be proven that the gas was flared or vented prior to project implementation. Waste gas generators and recipient plants that consume steam and/or electricity shall be identified at the time of preparation of PDD and consultations with them shall be documented. To prevent double counting, users of energy exported have to sign a contract that they do not claim CERs. Only the following baseline scenarios allow application of the methodology:

Electricity is obtained from a specific existing plant or from the grid and heat from a fossil fuel based steam boiler

If the project is a cogeneration plant, all the recipients that are now served by the project would have got their energy from a common fossil fuel based cogeneration plant.

In case existing plants are identified as baseline scenario, the crediting period has to be shorter than the remaining lifetime of the plants.

Only look at CO_2

Project boundary: The spatial extent of the project boundary includes the industrial facility generating the waste gas/heat/pressure, the generator of process heat/steam/electricity and the user of process heat/steam/electricity (including the grid in case of electricity exports). Only CO_2 emissions are to be considered.

Baseline Scenario Matrix

Baseline Fuel Available in Abundance

Scenario Selection through Investment or Barrier Test

Baseline scenario and additionality: The baseline scenario is to be the most plausible of all realistic and credible alternatives to the project, which would provide output equivalent to the combined output of the all the sub-systems in the project case with fuels available at the project site. The alternatives can include several sub-systems to cover steam and power requirements and possible alternative uses of waste gas/heat/pressure. They have to cover the three elements covered by the project boundary, which gives rise to 4 possible alternatives for the use of waste gas, 8 alternatives for electricity generation and 9 alternatives for heat generation. These alternatives are to be combined in a scenario matrix; only certain combinations are covered by the applicability conditions. The fuel used for the baseline energy provision has to be the fossil fuel with the lowest carbon emission factor available "in abundance" in the host country. Subsequently, the investment or barrier test of the latest approved version of the consolidated additionality tool is used to eliminate non-feasible options. Among the remaining alternatives, the alternative with the lowest baseline emissions is chosen as baseline scenario.

Additionality is assessed using the consolidated additionality tool.

Baseline emissions

Under the baseline scenario where electricity and heat are generated separately in existing facilities, for each facility receiving electricity/heat, the energy received is multiplied by the applicable emissions factor from energy generation.

Default Efficiency for Captive Power Plant 60%

Share of Steam produced by Waste Gas is Proxy for Energy

Discount due to Increase of Waste Gas Production

Greenfield Projects to use average Waste Gas Production Rate as per Nameplate

In case of electricity supplied by an electricity grid, ACM 0002 or AMS I.D are used to determine the emissions factor.

If a captive power plant is the baseline, the efficiency of the plant is to be estimated conservatively. Here, developers can choose among assumed optimal operation conditions, the higher of two power plant manufacturer nameplate efficiencies, an estimate based on load-efficiency curves or a default efficiency of 60%.

The emissions derived for the baseline scenario are then multiplied by the share of electricity provided from waste gas. The share is calculated on the basis of the amount and the heat rates of fossil fuels and the waste gas used. If the heat rate of the waste gas cannot be measured, one shall measure the share of the steam provided by burning waste gas of total steam produced..

A discount factor is introduced if the quantity of waste gas generated and used in the project is higher than in the pre-project situation. The discount equals the ratio of pre-project waste gas generation (maximum reached during the 3 years before project start) to post-project waste gas generation.

For new plants or plants that use waste pressure, the average waste gas/heat/pressure generation per unit of product is calculated on basis of equipment manufacturer's specifications. The maximum "pre-project" waste gas generation is then derived by multiplying production with that average rate. If manufacturer's specifications are not available, an independent process expert has to provide an estimate of the average rate.

Default Boiler Efficiency 100%

For heat, an analogous approach is applied, with default boiler efficiency set at 100%.

Default Cogen Plant Efficiency 90%

If a cogeneration plant is the baseline scenario, the electricity and heat uses are added up and multiplied by the plant efficiency, estimated in the same way as described above, with the default efficiency set at 90%. Discount factors for the share of energy produced from waste gas and pre-to post project waste gas generation are applied as well.

Direct fuel use or indirect fuel use due to application of steam for flaring of waste gas is also included in baseline emissions.

Project emissions

Project Emissions due to Cleaning of Waste Gas

Grid Default 1300g CO_2/kWh

Project emissions are emissions due to combustion of auxiliary fuel, emissions due to consumption of electricity for cleaning of waste gas before use and other electricity use by the project plant. If electricity is supplied from the grid, a default factor of 1300 g CO_2/kWh or ACM 0002 can be used. AMS I.D is eligible if electricity supply is less than 60 GWh. For captive power production, the default factor of 1.3 t CO_2/MWh or the actual plant emissions factor can be used.

No Leakage

Leakage

There is no leakage calculation.

Monitoring

Monitoring shall be conducted on the following items:

Ex ante

Measurement of Boiler Load Efficiency Functions

Goods Production

- Waste gas produced, preferably in the last 3 years but at least for 1 year
- Steam used to flare waste gas produced, preferably in the last 3 years but at least for 1 year
- Boiler load-efficiency functions, if this option is chosen for baseline determination. Measurement is based on recognized standards for the measurement of the element process efficiency, such as the "British Standard Methods for Assessing the thermal performance of boilers for steam, hot water and high temperature heat transfer fluids" (BS845) and to be done for at least 10 different load levels.
- Production of good which most logically relates to waste gas generation (average of last 3 years)

Ex post:

- Waste gas used by the project
- Power generation by the project differentiated according to recipients
- Heat generation by the project differentiated according to recipients
- Heat rate of waste gas
- Fossil fuels burned in the project and their emission factors differentiated according to fuel type
- Electricity grid emission factor according to applicable methodology (ACM 0002 or AMS I.D)
- Electricity consumption for gas cleaning equipment

Challenges encountered in the application of the methodology

Experiences from Use of ACM 0004

ACM 0012 has not been applied by any registered project or project submitted for registration. Therefore, only the experience related to application of elements of ACM 0004 in ACM 0012 can be used. The main challenges encountered in the application of ACM0012/0004 and resulting changes can be categorized into the following: (i) applicability conditions, (ii) baseline scenario definition, iii) project boundary, (iv) baseline emissions and (v) project emissions.

Expansion of Applicability Conditions

Contracts to avoid double Counting

The **applicability conditions** of ACM 0004 were too narrow and it became clear that there are other technologies than waste gas and heat use for electricity generation. Therefore, cogeneration and direct heat use have been added. Waste pressure use (e.g. through top recovery turbines) had already been added in a revised version of ACM 0004[222]. Electricity export to the grid and energy sales have been allowed, if contracts are signed that exclude double counting[223]. The project can be done by an energy service company. The concept of "recipient plant" was introduced to cover the plants to which energy exports are made[224].

More detailed Set of Baseline Scenarios

Conservative Choice among Plausible Alternatives

Baseline scenario definition was seen as too coarse and the role of non-economic factors on decision making acknowledged. The original set of 6 baseline scenarios that looked at energy production and use within the project boundary was substituted by a baseline scenario matrix with 21 entries in three columns, covering waste heat generation, energy production and energy use. Instead of choosing the most economically attractive alternative, the alternative with the lowest emissions among the "credible and plausible" alternatives has to be chosen as baseline scenario. Proof of pre-project flaring/venting is now required.

More Stringent Default Values as Difficulties in Measurement is realised

Additional items have to be included in **baseline emissions** and a more conservative approach applied, as it became clear that measurement of some parameters is difficult. Emissions from fossil fuel burning for gas flaring have been added. Determination of boiler efficiency of captive power plants has been made more stringent, by asking for optimal operating conditions, the higher of two manufacturer's nameplate efficiencies, establishment of load-efficiency curves or use of a high default efficiency. Default efficiencies such as 100% for a power plant boiler have been replaced by 60% for the entire captive power plant[225]. A further element of conservativeness has been introduced through the discount factor in case waste gas production increases.

Waste gas can be used in power generating units supplied by other fuels[226]. Shares of steam generation can be applied as proxies if the heat rate of the waste gas cannot be measured[227].

Project emissions: The item electricity generation for gas cleaning equipment was added. The oxidation factor was deleted, increasing the level of project emissions.

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222 This was due to clarification request AM_CLA_0015.

223 Response to clarification request AM_CLA_0041.

224 This issue was first raised in clarification request AM_CLA_0005, but not fully resolved until introduction of ACM 0012.

225 Response to clarification request AM_CLA_0040

226 The 7th request for deviation (Nov. 23, 2005) led to a corresponding revision of ACM 0004

227 AM_REV_033

5.4.4 AMS-II.D

Project Description

Small Scale Energy Efficiency in Single Industrial Facility

Energy efficiency and fuel switching measures implemented at a single industrial facility. Industry includes mining and mineral production[228]. The measures shall aim primarily at energy efficiency, such as efficient motors, switching from steam or compressed air to electricity or at specific industrial processes.

Applicability conditions: AMS-II.D (version 10) is applicable to replacements, modifications or retrofits of existing facilities or new facilities. The eligibility limit of 60 GWh (180 GWh thermal) energy saving for a small-scale CDM project applies:

Project boundary: physical, geographical site of the facility, processes or equipment that are affected by the project activity.

Baseline scenario and additionality:

Retrofits eligible until end of Lifetime of replaced Equipment

For retrofits, the baseline scenario is continued historical energy consumption until the point in time where replacement, modification or retrofitting would have taken place. From that time onwards, the baseline scenario is equal to the project. The determination of the technical lifetime is done according to the general approach described in Chapter 5.1.2, with the only difference that the replacement practices of the responsible industry have to be evaluated instead of the replacement practices of the project developer. If a range of time is the result of the evaluation, the earliest point of time is to be used.

For new facilities, the baseline scenario is the facility that would otherwise be built. The methodology does not specify how this is going to be determined and therefore is an empty shell that remains to be filled.

Emission reductions:

Energy Savings times Emissions Factor

Emission reductions are the energy consumption in the baseline scenario minus energy consumption in the project scenario, multiplied by the emission factor of the fuel used. For fossil fuels, IPCC default emission factors can be used. For electricity, the emission factor according to AMS I.D is used (see Chapter 5. 2)

Leakage

No Leakage if replaced Equipment is scrapped

Leakage has to be calculated if the equipment used in the project is transferred from another activity and if the replaced equipment is transferred to another activity. How the leakage is to be quantified is not specified. This has led users of the methodology to consider scrapping the equipment to avoid leakage calculation.

PoA: Lifecycle Fuel Emissions as Leakage

Leakage under a PoA: Fuel switch activities have to calculate leakage from lifecycle emissions of the fuel used by the project. This has to be done according to the rules specified in ACM 0009.

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[228] The inclusion of mining and mineral production was due to a request for revision by a project developer submitted on Nov. 28, 2006.

Monitoring:

Pre-Project Metering for Retrofits

For retrofits, the energy use of the facility "affected" by the project shall be metered. The methodology does not specify for which period the pre-project situation has to be metered.

For new facilities, only the energy of the new facility is to be metered.

Detailed Monitoring of Scrapping

Monitoring under a PoA: Monitoring should be conducted to check if the number of the equipments distributed by the small-scale CPA coincides with the number of the scrapped equipment. Equipment scrapped should be stored until the completion of this check. The scrapping of replaced equipment should be documented and independently verified.

Simplifications for the small-scale methodology: As compared to ACM0012, AMS-II.D applies default emission factors and does not define a minimum period of data for the pre-project energy use. There is no need to apply conservative values for the efficiency of replaced equipment.

Challenges encountered in the application of the methodology

The main challenges encountered so far in the application of AMS-II.D were i) definition of retrofits, ii) metering of energy use and iii) additionality testing.

Definition of Retrofits changed to include Modifications

Definition of retrofits: For the project "Installation of Additional Urea Trays in Urea Reactors (11/21- R01)" (UNFCCC no. 0587), in October 2006, a request for review was launched as this project neither replaced existing equipment nor represented a new facility. It involved a retrofit, the addition of 5 sieve trays to the existing sieve trays, but not replacement of existing equipment. The version 7 of AMS II.D. limited retrofit measures to those that involve replacement of existing equipment with new equipment. The project was registered and the methodology changed to include "modifications".

Metering of energy use

Metering of Energy Use through Proxies

For the project 0587, the request for review also addressed the issue that urea production and steam consumption are monitored but energy use is only calculated. The validator argued that the manufacturing process for urea is very complex and has hence has been looked into from an overall perspective. The parameter of the specific consumption of steam to urea gives a clear indication of the energy saved. There is, however, no change foreseen in the consumption of power due to an increased production of urea. This was the logic adopted for the project monitoring of the urea production and the steam consumption in the urea plant. The EB accepted this argument.

With regard to the project "Energy efficiency measures at cement production plant" (UNFCCC no. 1068) as well as "Energy Efficiency Measures At Cement Production Plant In Central India" (UNFCCC no. 1072), energy consumption before and after project was tested for 13 equipment modifications in each of the two plants on a basis of several hours. The EB required corrections to correctly describe the unit and frequency of measurement of parameter(s) representing the energy use of each equipment.

5.4.5 AM0046

This methodology warrants particular attention as it is the first methodology explicitly designed for a Programme of Activities and the first large-scale methodology for end-use efficiency. It has a very elaborate system of sampling groups.

CFL Distribution Programmes

Only 4 Lamps per Household

No Replacement of Fused Lamps

Applicability conditions: Distribution of energy-efficient lamps to households. A project coordinator sells efficient lamps at a subsidized price or donates them to households in a distinct geographic area in exchange against previously used lamps. Lamps distributed are not allowed to have a higher light output than the returned lamps. Each household can receive a maximum of 4 lamps. The collected lamps are scrapped. Participants of the sample groups are incentivized by a social lottery. In the project area, no registered CDM project of the same type may exist. Fused lamps distributed by the project cannot be replaced.

Project Areas defined as Squares

Project boundary: The project boundary encompasses all project areas and the electricity grid to which the households are connected. Each project area is to be a square of 4 km^2 for urban and 3600 km^2 for rural areas.

Baseline scenario and additionality:

Baseline Sampling Group defines Baseline Energy Use

The baseline scenario use of lamps is defined through the behaviour of a statistically significant baseline sample group that is not part of the project. The conservative (=low) end of a 95% confidence interval is used to define baseline energy use.

Additionality from Perspective of Coordinator

The consolidated additionality tool is applied, but only from the perspective of the project coordinator.

Emission reductions:

Energy Savings: Difference of Baseline and Project Sampling Group Energy Use

The emission reduction is determined through the difference in absolute lighting energy use between the baseline sample group and a statistically significant project sample group, multiplied by the grid emissions factor determined according to ACM 0002, taking into account technical distribution losses. If the electricity consumption of the baseline sample group is significantly higher than the consumption of a baseline cross-check group, the lighting energy use of the baseline sample group will be discounted accordingly. Analogously, project lighting use will be increased by a multiplier if the electricity consumption of the project sample group is significantly lower than the consumption of a project cross-check group. The conservative (=high) end of a 95% confidence interval of energy use across the sample group is used to define project energy use.

Leakage

Scrapping of replaced Lamps

Scrapping of returned lamps is required to avoid leakage.

Monitoring

Sampling Groups for Monitoring

Cross Check Groups

Minimum Group Size

Measurement Equipment for Each Lamp in Sampling Groups

Power Correction Factor

Four sampling groups are used for determination of baseline and project emissions. Two groups serve for determination of baseline and for project emissions (baseline and project sample groups), with another two serving to cross-check the results achieved (baseline and project cross-check groups; these are re-established by random choice at the start of each monitoring interval): The minimum size of the groups at the start of the project is 100 households, and CERs cease to accrue if the size of a group falls below 60. Buffer groups can be established to prevent a fall of the group size under the critical threshold. The distribution of sample group households across project areas shall be proportional to the lamp distribution pattern across project areas. Members of the project sample group should not receive more information than other households and should not be particularly encouraged to participate in the project. Measurement equipment shall be installed in all sampled households, either to measure all lamps in the households or only those in the living areas. This metering equipment, which can either be an electricity or a run-time meter, has to be attached to the lamp or the cable, not the socket to prevent that project participants are involuntarily keeping the lamps distributed by the project. Run-time meters can only be used if all lamps sold in the host country perform according to the standards IEC60064 (incandescent lamps) and IEC60901 (CFLs), if the power rating is measured on site or if the lowest power rating found in the baseline sample group and the highest power rating found in the project sample group is used for the calculation. Moreover, a power correction factor has to be applied that takes into account that lamp electricity use depends on the actual grid voltage achieved.

Monitoring shall be conducted as follows.

Ex ante

Monitoring Spatial Location of Each Household

Detailed Information on all Lamps in Sampled Households

- Power rating of each lamp type distributed, through laboratory measurements
- Grid voltage
- GPS data to define the project areas;
- Household name, address, GPS data, applicable project area, for all sample groups;
- Electricity consumption of sample group households according to electricity invoices
- Date when the household has been added to the sample groups;
- Date of first spot check in sample groups;
- Place and number of lamps found during a first spot checks in the household/ in its living area;
- Clear identification of each lamp found during a spot check;
- Type of measurement equipment installed for each of those lamps and date of its installation
- Information whether the lamp and its measurement equipment is working appropriately,

- Information on any changes made to the measurement equipment (exchange, repair, etc);
- Technical distribution losses of the grid. Instead of monitoring, a default value of 5% can be chosen

Detailed Information on all Distributed and Collected Lamps

Ex post

- Household name, address, GPS data, applicable project area and date of return of old and distribution or sale of efficient light bulbs for all households participating in the project
- Electricity consumption of sample and cross-check group households according to electricity invoices
- Number and power rating of the returned and distributed lamps
- Average grid voltage
- Lamp electricity consumption/lamp utilization hours of each household in the baseline and project sample group. This has to be done within a period of three weeks.
- Place and number of lamps found during spot checks in the household/ in its living area and information on which lamps have been added or removed by the household since the last spot check
- Status of households in the sample groups (moves etc.)
- Scrapping of returned lamps, by an independent party
- Data for calculation of Combined Margin according to ACM0002

Challenges encountered in the application of the methodology

Complexity of Methodology prevents its Application

It is unlikely that the methodology will ever be applied due to the complexity of monitoring requirements. Even the developers of the methodology are now using small-scale methodology AMS II.C, as the threshold of 60 GWh is sufficiently high to make projects viable. As AMS II.C has several gaps, monitoring concepts of AM 0046 are being used to operationalize AMS II.C.

Methane Recovery/ Avoidance Methodologies

5.5 Methane Recovery/Avoidance

5.5.1. Methodologies analyzed

Large Scale	ACM-0001 (version 6) "Consolidated baseline methodology for landfill gas project activities"
Small Scale	AMS-III.D (Version 13) "Methane recovery in agricultural and agro industrial activities"
Small Scale	AMS-III.E (Version 13) "Avoidance of methane production from biomass decay through controlled combustion"

5.5.2 Basic concept

Category Description

Methane Reduction from Waste or Prevention of Emissions due to alternative Waste Treatment

This section analyses two project types. The first type of projects mitigates global GHG emissions by capturing and destroying methane from *inter alia* landfills, unmanaged agricultural waste or agro-industrial waste. The second project type abates the formation of methane at source by preventing the decay of biomass or other organic residues that would have otherwise been left to decay as a result of anthropogenic activities. An energy production component may be added when the project also contributes to displacing the use of fossil fuel energy sources by producing energy through methane combustion or by supplying the gas to a natural gas network.

Methodological Concept

Methane Reduction by Project times Methane GWP

Emissions reductions attributable to methane recovery and destruction activities in year "y" are defined as:

ER_y	=	$(MD_{project,y}$	–	$MD_{reg,y})$	X	GWP_{CH4}	–	PE_y
Emission Reductions		Methane destroyed by the project		Methane destroyed to comply with relevant regulations		CH_4 Global Warming Potential		Project Emissions

There is no leakage arising from this type of activity.

Methane Prevention: Methane Generation Potential of Waste treated

In the case of projects reducing methane emissions through controlled combustion, preventing the decay of organic waste, emission reductions are defined as follows:

ER_y	$= (BE_{CH4,SWDS,y}$	$- MD_{reg,y}$	$X\ GWP_{CH4})$	$- (PE_{y,comb}$	$+ PE_{y,transp}$	$+ PE_{y,power})$
Emis-sion Avoid-ance	Yearly methane generation potential of the waste	Methane destroyed to comply with relevant regula-tions	CH_4 Global Warming Potential	Project emissions from non biomass waste burning	Project emissions from transport distances increase	Project emissions from power consump-tion

Leakage is not considered, except under conditions mentioned in the analysis of AMS-III.E below.

In both cases, small-scale projects shall reduce anthropogenic emissions by sources by less than 60 kilotonnes CO_2 eq. annually.

Claiming additional emissions reductions by electricity or heat production

Electricity Generation from Methane Combustion as per Electricity Grid Methodologies

Projects can claim additional emission reductions if the biogas they capture is burned and used to generate electricity or heat and if it can be demonstrated that this energy generation contributes to displacing a fossil fuel based energy source.

Landfill gas projects wishing to claim emissions reductions for displacing natural gas

Displacement of Natural Gas in Pipelines

Alternatively, projects capturing methane may choose to supply gas to a natural gas distribution network rather than burning the gas to produce energy, hereby displacing the usage of natural gas. If emissions reductions are claimed for displacing natural gas, projects may use methodology AM0053 for establishing the project's baseline scenario in combination with monitoring methodology ACM0001.

Projects using waste that has partially decayed in a disposal site[229]

Discounting of Waste landfilled in the Past

In the case of projects that obtain waste from existing solid waste disposal sites, the calculation of the yearly methane generation potential of the waste combusted from the project beginning up to the year "y" will consider the age of the waste at the start of the project. AMS-III.E (version 13) defines the allowed options to calculate this parameter.

5.5.3. ACM0001

Project Description

Landfill Gas Capture

ACM0001 is applicable to landfill gas capture projects. Projects registered using this methodology propose destruction by flaring, the use of the captured gas to generate electricity, generate thermal energy or supply into natural gas grids.

Applicability conditions

ACM0001 (Version 6) is applicable to projects where the baseline scenario is the partial or total atmospheric release of the landfill gas. If emissions reductions are claimed for the displacement of natural gas, AM0053 should be used as the baseline methodology in conjunction with ACM0001.

Project Boundary

The project boundary is defined as the site where the landfill gas is captured and destroyed (or used). If the project produces energy, the project boundary shall also include all power generation sources to which the project is connected, either directly (e.g. captive power plant) or through the grid.

Baseline scenario and additionality

To determine the baseline scenario, ACM0001 (version 6) requires the identification of all credible baseline alternatives to the project using of the latest version of the "Tool for the assessment of additionality".

Baseline Scenario continued Venting or Flaring

Upon establishing the appropriate baseline scenario, project proponents must assess whether their proposed project suits the requirements of ACM0001. According to its latest version (version 6), only projects with the following baseline scenarios can qualify:

- The most plausible baseline scenario to the flaring component of the project is the total release of the landfill gas to the atmosphere or partial capture and flaring of the landfill gas.
- The most plausible baseline scenario for the energy component of the project is one of the following:

[229] Only applicable to AMS-III.E

– Had the project not occurred, the energy would have been produced by an existing or a new on-site or off-site fossil fuel fired captive power plant;

– Had the project not occurred, the energy would have been produced by an existing and/or new grid-connected power plant;

– Had the project not occurred, the heat produced by the project would have been produced by an existing on-site or off-site fossil-fuel boiler or by the construction of a new one.

Baseline Emissions

Host Country Regulation defines Baseline Scenario Collection Rate

Relevant policies and regulations related to the management of landfill sites must be identified and their applicability assessed. These may include regulations and policies that require landfill gas to be captured or destroyed to achieve certain environmental or safety standards. Project participants must follow changes in relevant regulation and policies and adjust their baseline scenario accordingly at the beginning of each crediting period.

Adjustment for the Stringency of Regulation

If regulatory or contractual requirements do not specify the amount of methane required to be captured or flared in the absence of the project, baseline emissions should be calculated using an adjustment factor (AF). ACM0001 provides the following guidelines to estimate AF:

- If the use of a specific collection and flaring system is mandated by regulations or contractual arrangements, then the ratio of the flare efficiency of that system to the flare efficiency of the system proposed by the project should be used.
- In cases where a regulation or a contractual agreement mandates the capture and flaring of a certain percentage of the methane generated by the landfill site, the AF should be calculated by dividing that percentage by the assumed efficiency of the flare the project plans to use.

For projects that captured landfill gas into energy or that supply natural gas to a network, a separate baseline scenario for this additional activity must be established. This type of project shall calculate the amount of fossil-fuel energy displaced by the production of energy or the supply of gas.

Project Emissions

Project participants shall use the latest version of the "Tool to determine project emissions from flaring gases containing methane" (see Box 35). Additionally, possible CO_2 emissions resulting from combustion of other fuels than the methane recovered should be accounted as project emissions.

Emission Reductions

The emissions reductions achieved by projects applying ACM0001 can be divided in two categories.

Landfill gas capture and flaring activities

Two Components: Methane Reduction from Venting and Displacement of Grid Electricity

Emissions reductions stemming from projects that only capture and flare the landfill gas correspond to the amount of methane destroyed/combusted by the project, minus the amount of methane that would have been destroyed/ combusted had the project not occurred, minus the emissions attributed to the energy and/or fuel consumed throughout the development and operation of the project. These include for instance emissions attributable to the use of on-site generator during the early development stage of the project, emissions stemming from the operation of the gas pumping system, and/or emissions attributable to the use of electrical power to operate the project.

Ex ante Estimate of Baseline Emissions required

Project proponents should provide an *ex ante* estimate of the emissions that would be released from the landfill through time had the CDM project activity not occurred. Project proponents can estimate *ex ante* emissions using the latest version of the *"Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site"* (see box 29).

Baseline Emissions Monitoring ex post through Gas flares/used

The project's emissions reductions are measured *ex post* by monitoring the quantity of methane flared and gas used to produce energy when applicable, and the total quantity of methane captured. More specifically, project participants must compare the sum of the methane quantities fed to the flare(s), to the power plant(s) and to the boiler(s) with the total metered quantity of methane captured from the landfill site. The smallest value of the two is to be considered as the project's emissions reductions.

Box 29: **The "Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site"**[264]

Methane emissions that would have been generated by solid waste disposed in a landfill site in the absence of the project activity are calculated using a first order decay (FOD) model. In a nutshell, the FOD model differentiates between types of waste with different decay rates and different fractions of organic carbon. In addition, it takes into account the effects of different climatic conditions and waste management practices. Once the composition and the volume of the landfill's waste stream are assessed, the FOD model uses these parameters to estimate the yearly methane emissions that would occur in the landfill site in the absence of the project activity.

Application of First Order Decay Model for Baseline Emissions Estimate

The FOD model can be applied in cases where the waste that would be disposed can clearly be identified. Since the project's baseline scenario must be reassessed at the beginning of each crediting period, several parameters in the model can be changed to account for changes in the baseline scenarios. For more information on how to apply the FOD model, please refer to the latest version of the Tool.

Landfill gas capture activities to produce energy or supply gas

Emission reductions from projects that capture landfill gas and produce energy (either electricity or thermal energy) or supply natural gas stem from the net amount of methane destroyed/combusted by the project plus the amount of fossil-fuel energy displaced by the production of energy or the supply of gas (in CO_2 eq.), minus the emissions attributed to the energy and/or fuel consumed by the project. If the project uses electricity for its operations and provides electricity to the grid, only the net quantity of electricity supplied to the grid should be accounted.

[230] EB 26, Annex 14.

Default Emissions Factor for Captive Power Plant

Guidance to assess baseline emissions for projects generating electricity: To determine baseline emissions for projects displacing electricity from an on-site/off-site fossil fuel fired captive power plant, the CO_2 emission intensity of the source of electricity displaced must be calculated. Project participants can either use a fix default value of 800 g CO_2/kWh or estimate the emission intensity of the displaced energy source using the equation stipulated in ACM0001. In case the baseline scenario is electricity coming from the grid, then the emission factor should be calculated using ACM0002. If the electricity generation component of the project falls under the small-scale thresholds, AMS-I.D should be applied.

Default or Highest of Nameplate or Measured Boiler Efficiencies

Guidance to assess baseline emissions for projects generating thermal energy: As for projects displacing fossil-fuel based energy sources through electricity production, projects producing thermal energy must determine the emission factor of the energy they displace. ACM0001 provides guidance to assess the CO_2 emissions intensity of the fuel that feeds the boiler used by the project and to estimate its efficiency. ACM0001 gives two options to estimate the boiler efficiency. Project participants can either choose the highest of these three values ((i) measured efficiency of the boiler prior to project implementation, (ii) measured efficiency during monitoring, or (iii) the manufacturer's information), or assume an efficiency value of 100% based on the net calorific values. To determine the CO_2 emission factor of fuels used in the boiler to produce the thermal energy in the absence of the project, project participants should use appropriate local or national values. If these are not available, IPCC emissions factors should be used.

Default Grid Electricity Emissions Factor, or Use of ACM 0002

Guidance to determine the emission factor of the energy used by the project activity: To assess the CO_2 emission factor of the energy consumed because of the project, project participants may choose between 3 methods:

- Use a default emission factor of 1.3 tCO_2/MWh;
- In cases where the project energy is purchased from the grid, calculate the emission factor as prescribed by ACM0002 or AMS-I.D, whichever is applicable;
- In cases where the project energy is supplied by an on-site fossil fuelled power plant, project participants may estimate the emission factor according to the equation provided in ACM0001.

Leakage

No Leakage

No leakage needs to be considered under this methodology, no matter whether the project produces energy or supplies gas.

Monitoring

Regulations to be monitored ex ante

Ex ante: Prior to the validation of the project, the amount of methane that will be captured to comply with relevant regulations or contracts ($MD_{reg,y}$) should be estimated. If relevant regulations or contractual arrangements exist, monitoring shall be done to consider the mandate to use specific collection and flaring systems or the mandate to capture and flare a percentage of the methane generated by the landfill, in order to calculate $MD_{reg,y}$.

Ex post: The main parameters that need to be recorded throughout the project cycle are:

Methane Quantity

- The quantity of methane captured by the project activity;
- The quantity of methane flared by the project activity;
- The quantity of methane used to generate energy;
- The total quantity of methane generated by the project activity;
- The energy generated by the project (electric or thermal);
- The energy consumed by the project activity coming from fossil fuel sources.

Additionally, ACM0001 gives the following monitoring guidelines:

Measurement Equipment to measure Methane Fraction, Temperature and Pressure

- The fraction of methane in the landfill should be measured with a continuously analyzer if possible, or with periodical measurements at a 95% confident level;
- Temperature and pressure of the landfill gas must be recorded in order to assess methane density;
- In cases where the project baseline requires the partial capture of landfill gas for safety or odour concerns, the fossil fuel used in the baseline scenario should be accounted for.

Box 30: Clarifications on landfill gas flow monitoring

Two requests for clarification were submitted questioning the necessity of installing flow meters at all measurement points throughout the flaring and energy system as required by ACM0001. Both requests argued that installing flow meters at each measurement point incurred significant costs for project developers while it did not necessarily increase the level of precision of measurements.

Meter Redundancy upheld by EB

The first of these submissions[265] requested clarification on whether projects that flare landfill gas and generate both electricity and thermal energy could install only three flow meters (instead of four) and determine the value of the fourth meter by a simple rule of three. To illustrate this, it proposed to measure the amount of landfill gas flared by subtracting the values of the two meters recording the amount of landfill combusted in an electricity generator and the amount of landfill gas combusted in a boiler, from the value recorded by the meter measuring the total amount of landfill gas captured. The MP responded negatively to this request arguing that the measurement redundancy was in line with the conservativeness of ACM0001. Nonetheless, the MP proposed that a rule of three could occasionally be used in cases where one of the meters would fail, and that a definition of "occasionally" would have to be drafted. EB 24 endorsed the MP's decision on this issue.

Gas Flaring Projects only need one Meter

In a similar vein, a submission[266] requested clarification from the MP on whether flow meters had to be installed at each measurement point for project activities that only flare the landfill gas. In this case, SGS argued that such projects were required to monitor the "total landfill gas flow" and "the flow to the flare", which are essentially the same flow. Because installing two flow meters did not increase the level of precision of measurements but increased project costs, they questioned whether the clarification given by the MP on previous clarification also applied to projects that only flare landfill gas, and in such cases, whether it was necessary to install two flow meters. The MP acknowledged that the redundancy in measurements was not necessary for projects that only flare landfill gas. Such decision was supported by EB25 and led to a revision of ACM0001.

[231] See AM_CLA_0020
[232] See AM_CLA_0028

Use of one Meter in specific Case

Box 31: Deviation of monitoring methodology ACM0001: Using one flow meter for measuring LFG flow to leachate evaporator and enclosed flare[267]

This request was submitted by the project "Anding Landfill Gas Recovery and Utilization Project" on September 13, 2006. The DOE who submitted the request raised that the project – which had already been validated – was not using a separate, direct meter for measuring the landfill gas flow to the flare as requested by ACM0001 (version 2). Instead, the project used two indirect flow meters, one for measuring the LFG to the recovery system and one from the capture system to a leachate evaporator unit. The DOE argued that this specification had been considered in the project's monitoring plan and that there was physically no room for adding a separate flow meter to measure the flow to the flare. According to the DOE, the lack of a separate meter to measure the flow to the flare would not impact the emissions reductions estimates since the system was designed to ensure that all captured LFG not directed to the leachate recovery system was automatically going to the flare.

Considering that the requirement to install an individual meter for measuring LFG flow to the flare had only been adopted to ensure redundancy in measurement, the DOE requested a deviation from ACM0001 (version 2) to apply the monitoring plan of the project's validated PDD. Interestingly, the EB approved the DOE's request for deviation, although it represented a shift away from the redundancy in measurements principle embedded in the CDM. Nonetheless, the EB requested the DOE to submit a request for revision of the project's monitoring plan to ensure that the project complies with the latest version of ACM0001 for future monitoring periods.

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[233] See request for deviation "Deviation of monitoring methodology ACM0001: Using one flow meter for measuring LFG flow to leachate evaporator and enclosed flare" at http://cdm.unfccc.int/Projects/Deviations/index.html, October 1, 2007.

Monitoring of Flare Efficiency

Box 32: Measurement of the flare efficiency

Another outstanding issue that influenced the development of ACM0001 relates to the requirement to measure the flare efficiency (i.e. the fraction of methane destroyed within the flare) throughout the project cycle.

A request for revision[268] argued that the flare efficiency monitoring requirements stipulated in ACM0001[269] posed several limitations:

1. Obtaining reliable and comparable measurements was problematic because sampling of the exhaust gas could hardly be repeated under similar conditions.
2. Project participants generally face difficulties to regularly monitor the exhaust gas of the flare due to the hazardous nature of the operation, the specialized equipment required, the technical expertise needed, and the relatively high costs involved, which often require project participants to hire foreign consultants to perform the operation.
3. Because flares are designed to completely destroy the methane they receive, it is unlikely that even highly precise equipment could detect remaining traces of methane in the flare. It argued that available equipment is primarily designed to detect traces of other exhaust gases (such as NO_x, SO_x, and VOCs) and therefore may not be precise enough to efficiently detect traces of methane in the exhaust gas.

Project Developer proposed Default Values or Use of Proxies

Thus, two alternative methods were proposed to assess flare efficiency:

1. Use of default values: Pointing out that ACM0008 (for flares destroying coal-mine methane) and AM0016 (for flares destroying animal waste methane) both permitted the use of default value to estimate flare efficiency (99% for enclosed flares, 50% for open flares), DNV argued that landfill activities flaring methane should be allowed to use the same default values as the processes involved are not technically different.

2. Determination of flare efficiency using flame temperature and combustion time: The submission also argued that increasingly, industrialized countries allowed their methane-regulated industries to measure flare efficiency using flame temperature, pointing out recent peer-reviewed studies showing a correlation between flame temperature and methane destruction level. For instance, it was raised that the Dutch government required a minimum flame temperature of 900˚C to ensure an efficient combustion of methane, while other studies suggested a minimum flame temperature of 760˚C. It was therefore proposed that flare efficiency be determined using flame temperature, providing that a curve correlating a set of combustion temperature values to a set of efficiency values be made available to project proponents.

MP Rejection of Proposal

Though it recognized the difficulties related to measuring efficiency of open flares, the MP rejected the request to allow project participants to use default values to assess flare efficiency, arguing that these did not provide the level of precision needed to accurately estimate the emission reductions. It added that the efficiency of enclosed flares could be easily monitored at a relatively low cost. However, the MP did not give any explanation as to why default values could be used under ACM0008 and AM0016 and not under ACM0001.

Interestingly, the MP proposed a revision to ACM0001 – *albeit* unrelated to this request for clarification – allowing project participants to use a default flare efficiency value of 50% in cases where flare efficiency would deliberately not be monitored. This recommendation indirectly contributed to eliminating certain barriers faced by project participants operating an open flare system (as raised by DNV).

[234] See AM_REV_0012

[235] ACM0001's guidelines to assess flare efficiency allows for two different monitoring options: (1) continuous monitoring of flare efficiency during operating hours; or (2) quarterly

Box 32: Measurement of the flare efficiency *(continued)*

Additionally, the MP stated that there was not enough evidence to justify using flame temperature to determine flaring efficiency. It recognized that flare efficiency was a function of several parameters, including flame temperature, combustion time and turbulence, but argued that temperature alone could not be used to accurately determine flare efficiency. In line with the MP's decision, EB 25 rejected DNV's request. These decisions led to the approval of ACM0001 version 4.

Tool developed to resolve Issue

However, such revisions did not resolve the issue entirely. Indeed, other methodologies for projects flaring methane had also requested clarifications on flare efficiency measurement guidelines in the past. This led the MP to reconsider the way it interpreted measurement of flare efficiency and led EB 28 to adopt the *"Tool to determine project emissions from flaring gases containing methane"* (see Box 33) in December 2006. This in turn triggered the revision of several methodologies for project activities that involved methane flaring, including ACM0001.

Open Flare Default Efficiency of 50%

This Tool brought further clarifications to several elements that had been raised throughout the evolution of ACM0001, particularly with regards to the use of alternative methods to assess flare efficiency such as default values and correlated parameters, such as combustion parameters. Notably, the Tool recognized that recording periodic measurements to assess flare efficiency for open flares was a hazardous process and that a flare efficiency default value of 50% could be used providing that it can be demonstrated through constant monitoring that the flare is operating.

For enclosed flares, the Tool provided two new options to determine flare efficiency:

Enclosed Flare Default of 90%, if Manufacturer Specifications are complied with

The use of a default flare efficiency value of 90%, providing a continuous monitoring of compliance with the specifications provided by the flare manufacturer, including temperature, flow rate of residual gas at the inlet of the flare;

Continuous monitoring of the flare's methane destruction efficiency.

EB Turnaround regarding Flare Efficiency

For open and enclosed flares alike, the Tool specifies that a flare efficiency of 0% must be assumed in cases where the temperature is not recorded or when the combustion temperature is inferior to 500°C. In cases where project participants choose to measure efficiency using the default value, a seven-step procedure must be applied as stipulated in section II of the Tool[270].

In short, the Tool responded to many of the concerns and modifications requests submitted throughout the evolution of ACM0001 by providing alternative methods to assess flare efficiency. Interestingly, similar flare efficiency measuring methods had been proposed approximately 8 months before the adoption of the Tool (in April 2006) but were rejected by the EB on the basis that these did not meet the level of precision required for flare efficiency measurement under the CDM. The reasons behind this turnaround remain dubious.

[236] These parameters include: The mass flow rate of the residual gas that is flared, the mass fraction of carbon, hydrogen, oxygen and nitrogen in the residual gas, the volumetric flow rate of the exhaust gas on a dry basis, the methane mass flow rate of the exhaust gas on a dry basis, the methane mass flow rate of the residual gas on a dry basis, the hourly flare efficiency, and a calculation of the annual project emission.

Temperature of Flare

Box 32: Measurement of the flare efficiency *(continued)*

Subsequently to the adoption of the *"Tool to determine project emissions from flaring gases containing methane"*, another request of clarification was submitted regarding the guidelines on flare efficiency measurement[271]. It expressed concern over the Tool's suggestion that a combustion temperature exceeding 700˚C could be a sign that the flare is not operating adequately and raised that a number of flaring systems had been designed to operate at temperatures higher than 700˚C while still ensuring a high level of methane destruction efficiency. Additionally, they mentioned that the UK Environmental Agency was recommending a combustion temperature of 1 000˚C for landfill gas flares to ensure high levels of methane destruction.

In response the MP stated that flaring combustion temperature may exceed 700˚C for several reasons, including flare design and manufacturing characteristics. The MP recognized that the temperature throughout the flaring chamber is non linear during combustion and may sometimes exceed 1000˚C. Hence, the MP clarified that a flare temperature greater than 700˚C could still provide accurate efficiency measurements, providing it was not caused by an incompatibility problem between the flare capacity and the gas flow or an inadequate air mixing or air quantity inside the flare leading to combustion taking place in the cooling zone or in the exhaust. Although EB 33 has taken note of the MP's recommendations over this request, the EB has not yet taken any decision over the issue.

5.5.4 AMS-III.D

Project Description

Small-scale Methane Reduction Methodology

Baseline Scenario anaerobic Decay

AMS-III.D includes projects proposing the recovery and destruction of methane generated from manure and waste from agricultural or agro-industrial activities. Baseline scenarios for this type of projects shall demonstrate that manure or waste would have decayed anaerobically. Projects using this methodology propose to mitigate and recover animal effluent related GHGs by improving animal waste management systems (AWMS) practices.

Applicability conditions

Project Scenario Anaerobic Digestion and Methane Recovery

Methodology AMS-III.D (version 13) is applicable to projects that propose measures to recover and destroy methane generated from manure and waste from agricultural or agro-industrial activities that would otherwise decay anaerobically. Two technology options can serve this purpose: (i) the installation of methane recovery and combustion systems on organic sources of methane emissions, or (ii) the change in management practices of biogenic waste or raw organic material to achieve controlled anaerobic digestion with a methane recovery and combustion system. In both cases, projects shall use measurement instruments to ensure all biogas produced by the digester is used or flared.

In the case of projects using sludge, AMS-III.D (Version 13) requests that the organic waste be handled aerobically. In cases where projects involve soil application, measures must be taken to avoid methane emissions in the final disposal site.

[237] See AM_CLA_0047

Expanding of Applicability Conditions…

Box 33: Considerations regarding the use of gas for heat generation

A submission[272] requested clarification on the use of recovered methane for electricity generation by the project. The submission wondered whether a small-scale project using AMS-III.D is eligible under AMS-I.A. if the methane recovered is used for off-grid electricity or heat generation. In response to this request, SSC WG 03 recommended to amend the AMS-III.D to expand the possible use of recovered methane in different categories of renewable project activities. Furthermore EB 22 decided to amend the methodology AMS-III.D to allow projects that generate electricity or heat by using the recovered methane to use the corresponding Type I methodology.

… but through separate Methodologies!

Box 34: Evolution of applicability conditions and allowed technologies

Initial applicability conditions for AMS-III.D allowed all types of methane recovery activities, including coalmines, agro-industries, landfills and wastewater treatment facilities. Several submissions have requested the development of new methodologies under Type III for specific activities or the inclusion of new activities under AMS-III.D.

Two Separate Methodologies for Wastewater Treatment

In the first case, a submission[273] proposed a new category to cover situations where (i) methane will be emitted from unmanaged lagoons to the atmosphere or (ii) methane will be emitted directly into the atmosphere by the anaerobic treatment facility. SSC WG 04 proposed the inclusion of a new category III.H "Methane recovery in wastewater treatment for measures that recover methane from biogenic organic matter in wastewaters". On the same issue and in response to a submission made by the De Martino WWTP upgrade project[274], SSC WG 04 recommended the new category AMS-III.I "Avoidance of methane production in wastewater treatment through replacement of anaerobic lagoons by aerobic system" for activities substituting wastewater treatment in 'anaerobic' lagoons with 'aerobic' systems avoiding generation of methane. Both new methodologies were approved by EB 22.

Further Expansion of Applicability Conditions

Another two submissions[275] requested the expansion of applicability conditions to cover project activities that change manure management practices. One addressed the use of the FOD model to calculate baseline methane emissions, while the other one proposed the use of the lowest value between the value resulting from using the "Tier 2 Approach for Methane Emissions from Manure Management" from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and the actual amount of methane recovered. In response to these requests, SSC WG 06 recommended the revision of AMS-III.D to expand its applicability to cover project activities that change manure management from systems such as "lagoons", "liquid/slurry", "solid storage" or "drylot" to "anaerobic digestion" for the treatment of swine or cattle manure. AMS-III.D (version 13) defines that baseline emissions shall be calculated using the most recent *"Tier 2 approach of the 2006 Guidelines for National Greenhouse Inventories for Methane Emissions from Manure Management"* developed by the IPCC.

238 See SSC_016
239 See SSC_024
240 See SSC_040
241 See SSC_046 and SSC_051

Project boundary

The project encompasses the physical, geographical site of the methane recovery facility.

Baseline scenario and additionality

The baseline scenario is the situation where, in the absence of the project, biomass and other organic matter are left to decay anaerobically within the project boundary and methane is emitted to the atmosphere.

Beyond the barrier analysis, project participants may use other tools to complement their additionality analysis, including the latest version of the *"Tool for the demonstration and assessment of additionality"*.

Baseline Emissions

Baseline Scenario: Waste that would decay anaerobically

Baseline emissions are calculated using the amount of waste that would decay anaerobically in the absence of the project and the appropriate emission factor. The latter should be calculated taking into account the amount of volatile solids produced in the manure and the maximum amount of methane able to be produced from that manure, as well as the characteristics of the manure management system[242].

Project Emissions

CO_2 emissions only

Within the project boundaries, project participants shall only consider CO_2 emissions from the use of fossil fuels or electricity to operate the facility. AMS-III.D provides no guidelines on how to calculate these emissions.

Emission reductions

Considering the low energy consumption of this type of projects and that leakage measurement is not required (with the exceptions mentioned below for PoA), project emissions and leakage are typically assumed to be zero. Hence, emissions reductions stem directly from the amount of methane fuelled or flared (with a maximal emission reductions equal to the methane generation potential calculated in the PDD for each specific year).

Default Flare Efficiency 90%, if Compliance with Manufacturer's Specifications, otherwise 50%

Open Flares Default Efficiency 50%

Flare efficiency: In the case of methane flaring, the flaring efficiency may be determined by (i) the adoption of a 90% default value or (ii) the continuous monitoring of the efficiency. If a default value is used, a continuous monitoring process must be done to ensure compliance with manufacturer's specification. Any non-compliance with these specifications shall result in the modification of the default value to 50% for all the duration of the non-compliance period.

Temperature of below 500°C leads to zero Reductions

In the case of projects using open flares, a default value of 50% should be used, and if at any given time the temperature of the flare is below 500°C, a default value equal to 0% should be used for this period.

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[242] For further guidance refer to 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 'Agriculture, Forestry and other Land use', chapter 'Emissions from Livestock and Manure Management'. http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.htm

Box 35: The "Tool to determine project emissions from flaring gases containing methane"

Projects flaring residual gas streams need to estimate the flare efficiency and the mass flow rate of methane in the residual gas stream that is flared in order to calculate emission reductions. This tool provides the appropriate procedures to calculate project emissions from flaring of a residual gas stream containing methane under the following conditions: (i) the residual gas stream to be flared contains no combustible gases other than methane, carbon monoxide and hydrogen and (ii) the residual gas stream to be flared shall be obtained from the decomposition of organic material or from gases vented in coal mines.

The calculation procedure includes steps to calculate project emissions from flaring based on the measured hourly flare efficiency or based on the default values for the flare efficiency. Steps 3 and 4 are only applicable in case of enclosed flares and continuous monitoring of the flare efficiency:

Seven-Step Procedure for Measurement and Calulation of Flaring Emissions

1. Determination of the mass flow rate of the residual gas that is flared
2. Determination of the mass fraction of carbon, hydrogen, oxygen and nitrogen in the residual gas
3. Determination of the volumetric flow rate of the exhaust gas on a dry basis
4. Determination of methane mass flow rate of the exhaust gas on a dry basis
5. Determination of methane mass flow rate of the residual gas on a dry basis
6. Determination of the hourly flare efficiency
7. Calculation of annual project emissions from flaring based on measured hourly values or based on default flare efficiencies.

Leakage

No Leakage

The methodology does not require any leakage calculation.

Monitoring of Scrapping in Case of PoA

Leakage under a programme of activities (PoA): If the project consists in the replacement of equipment the replaced equipment has to be scrapped, and scrapping has to be monitored, to avoid leakage calculation.

Monitoring

Limit of CERs to ex-ante Estimate based on First Order Decay Model

Use of IPCC Inventory Guidelines Tier Two Procedure

Ex ante: The maximal emission reduction in any year is limited to the yearly methane generation potential calculated for that year in the PDD. Normally, the emission factor necessary for this calculation would have to be calculated based on the monitoring of the volatile solid excreted by livestock category. Tier 2 for emissions from livestock and manure management of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories allows to estimate this parameter based on feed intake and digestibility, or alternatively, by laboratory measurements of livestock manure. If country-specific measurement values are not available, default factors as specified in the Guidelines can be used.

Monitoring of Gas Volume, Methane Content, Temperature and Pressure

Ex post: The following parameters shall be monitored at each verification period on each individual farm included within the project boundary.

- Amount of gas recovered and fuelled or flared.
- Fraction of methane in the biogas.
- Temperature and pressure of the biogas to determine the density of methane combusted.

Monitoring of Sludge Disposal

Monitoring shall also be done to ensure accuracy and the optimal operation of flares, as well as to ensure a regular maintenance, testing and calibration of flow meters, sampling devices and gas analyzers. The final application of sludge shall be monitored to ensure that no methane emission results from this activity.

On-Site Monitoring required

While Need for Methodology without On-Site Monitoring acknowledged by SSC-WG, no such Methodology has been developed

On-site inspection for project activities on multiple sites: Upon request of the EB, the SSC WG developed recommendations to clarify that the monitoring plan shall include on-site inspections for each individual farm where the project activity is implemented in order to ensure that the registered monitoring plan has been applied correctly. However, since AMS III.D is applicable to bundled projects with a large number of very small distributed units for manure management the SSC WG concluded that the proposed monitoring requirements might not be economically viable for such projects, and decided that it is more appropriate to develop new methodologies for such projects instead of modifying AMS-III.D.

These recommendations were accepted by EB 31[243], including the clarification that emission reductions shall be assessed *ex-post* through direct measures on methane fuelled or flared and guidance related to the definition of the flare efficiency to calculate the amount of methane destroyed by the project. No new methodology has been developed for this specific situation despite the SSC WG's recommendation.

5.5.5 AMS-III.E

Project Description

Avoidance of Decay of Biomass Waste

AMS-III.E covers a variety of activities that avoid methane emission by avoiding anaerobic decay of biomass or other organic matter. This methodology has been applied by projects like: steam production using waste wood and coffee waste, silica production using rice husk, or electricity generation project using palm oil production waste.

Applicability conditions

Incineration of Biomass

AMS-III.E (version 13) is applicable to projects that avoid the production of methane from biomass or other organic matter that would have otherwise been left to decay as a result of anthropogenic activities. Projects may include controlled combustion of waste coming from unmanaged landfills or waste stockpiles where no methane recovery would occur in the absence of the project and where the geographic boundaries of: (i) the source of biomass or organic matter, (ii) the project facilities, (iii) the final residues deposit and (iv) the itineraries between the three can be clearly identified. If the combustion facility is used for heat and/or electricity generation, those components of the project shall use a corresponding methodology under Type I projects.

Justification required why Methane Recovery is not used

Projects involving combustion of partially decayed waste mined from a solid waste disposal site (SWDS) shall provide justifications for not using methane recovery and combustion to reduce methane emissions. Additionally, if new waste is generated during the crediting period, the project shall demonstrate that there is adequate capacity at the combustion facility to treat the newly generated waste in addition to the partially decayed waste removed from the disposal site or, explain the reasons for combusting the partially decayed waste instead of the newly generated waste.

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[243] EB31, Annex 22

Project boundary

Transport of Waste included in Project Boundary

The spatial extent of the project boundaries includes the project site, the sites where the organic waste is sourced, the sites where the final residues produced by the project activity will be deposited and the traveling routes between these three locations.

Baseline scenario and additionality

Baseline Scenario: Decay of Waste

In the baseline scenario, it is assumed that the organic waste used by the project is left to decay within the project boundary, hereby generating methane emissions.

The barrier analysis can be complemented by other tools, including the latest version of the *"Tool for the demonstration and assessment of additionality"*, may be use in a voluntary basis to enhance the additionality analysis.

Baseline Emissions

Fresh Waste: Use First Order Decay Model

Projects combusting freshly generated waste: under this scenario, projects calculate their baseline emissions at any year "y", using the amount and the composition of the waste combusted since the beginning of the project and the first order decay (FOD) model (see Box 36).

Old Waste in Landfill

Projects combusting waste that has partially decayed in a disposal site: This scenario requires that calculation of the yearly methane generation potential of the waste combusted from the project at any year "y" considers the age of the waste at the project start. In this case the project proponents may:

Differentiate Waste Age and apply First Order Decay Model according to each Waste Vintage

(i) stimate the mean age of the waste contained in the disposal site at the beginning of the project, as the weighted average age of the waste. These should consider the yearly amount of waste deposited in the landfill site, from the inception of the site to the year preceding the beginning of the project.

(ii) Calculate the yearly methane generation potential of the SWDS, taking into account the total amount and composition of waste deposited since the inception of the site. The methane generation potential of the waste removed for combustion up to the year "y" will be estimated as proportional to the mass fraction of that waste, relative to the whole waste mass in the SWDS.

(iii) Estimate the quantity and the age distribution of the waste removed each year[244], and calculate the methane generation potential of that waste in the year "y".

[244] The estimation of the age of the portions of waste being removed from the disposal site and combusted each year may be done by topographical modelling of the wastes present in the relevant sections of the SWDS. This approach should include segregation of the wastes into even-age layers or volumetric blocks based on historical or constructive data (design of the disposal site). Information on quantity, composition, and age may be based on (a) historical records of the yearly mass and composition of waste deposited in the section of the disposal site where waste is being removed for combustion; or (b) historical production data for cases in which the waste at the site is dominated by relatively homogeneous industrial waste material.

Partial Decay added due to Request for Revision

Box 36: Considerations regarding partially decayed waste

In response to a request for revision[279], SSC WG 08 recommended to change the applicability conditions of AMS-III.E to include partially degraded disposed biomass waste. In consequence three options were included in the methodology to calculate the age distribution of the waste and the corresponding avoided methane emissions (see "Project activities combusting waste that has partially decayed in a disposal site" section above). The SSC WG also recommended the revision of the parameters used in the First Order Decay (FOD) model in accordance with the *"Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site"*. These recommendations were accepted by EB 29.

Regulation has to be taken into Account

Baseline emissions shall exclude methane emissions that would have to be captured and destroyed to comply with national or local safety requirement or legal regulations. If the baseline includes a reduction of the amount of waste dumped in the landfill through constant open burning, the situation should be taking into consideration if the FOD model is applied. No methane should be captured or flared in the baseline scenario.

Project emissions

Three Types of Project Emissions: CO_2 of Fossil Content of Waste, from Waste Transport and due to Electricity Use

The methodology defines three sources of emissions to be considered: (i) CO_2 emissions stemming from the combustion of the non-biomass carbon content of the waste and of the auxiliary fossil fuels used in the combustion facility, (ii) the CO_2 emissions due to incremental transportation distances between the collection, controlled combustion and final residues deposit sites minus the transportation emissions of the baseline scenario, and (iii) the CO_2 emissions related to the fossil fuel and/or electricity consumed by the project activity facilities, including the equipment for air pollution control required by regulations.

Emission reductions

Sampling to determine Waste Types

Emissions reductions are calculated using the *"Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site".*

If waste is generated during the crediting period, the amount of each waste type deposited each year must be determined using appropriate sampling techniques. In cases where there is not enough data to determine the pre-existing amount and the composition of the waste of existing SWDS, these can be estimated using parameters related to the population or industrial activity using the SWDS, or through a comparative analysis with other SWDS holding similar conditions at regional or national levels.

Leakage

Leakage to be assessed if Equipment is transferred

Leakage is generally assumed to be zero. Special consideration must be taken in the case of projects transferring controlled combustion equipment from another activity or to another activity, were leakage may arise at the site where the other activity is being developed.

Leakage under a programme of activities (PoA) is treated analogously as in the other methodologies

[245] See SSC_054 and SSC_056

Biomass Leakage: Proving that there is sufficient Biomass available

Box 37: Leakage in projects that produce energy

Projects using methodology AMS-III.E and producing heat or electricity need to consider additional leakage issues as defined in the *"General guidance on leakage in biomass project activities"*. Accordingly, projects must consider emissions related to biomass generation and biomass use from (i) shifts of pre-project activities, (ii) emissions related to the production of the biomass, and (iii) competing uses for the biomass.

Two projects ("GEEA Biomass 5 MW Power Plant Project" (UNFCCC no. 1089) and "Bandar Baru Serting Biomass Project" (UNFCCC no.1091)) were asked to correct their submitted PDD based on these issues. Project proponents were asked to provide more detailed data on the amount of biomass available in the project region and to demonstrate whether their respective projects were creating competition in the regional biomass supply chain.

Notably, project 1089 was asked to provide evidence that current and future regional demand for rice husk other than from the project activity was limited. Conversely, the project proponent was asked to include monitoring measures to assess regional biomass availability on an annual basis and demonstrate there is indeed a biomass supply surplus. In response to this request, the project proponent provided information related to rice processing and rice husk generation within a radius of 300 km of the project site to show that rice husk supply is more than three times larger than amount required by the project. The project developer proposed to consult rice processing associations and provide relevant statistics to estimate the supply surplus each year.

In a similar way, project 1091 did not include in its monitoring plan an annual evaluation of the regional biomass supply. Additionally, it did not include measures to consider potential leakage. Pursuant to the request for review it received, the project participant modified its monitoring plan to include a new parameter to assess the biomass supply in the region and modify its monitoring practices to include leakage as per the *"General guidance on leakage in biomass project activities"*.[280] The project participant also argued that since the project was planning to use only empty fruit bunches (EFB) for fuel and that this biomass source was a residue from the palm oil industry, the only potential leakage source arose from the competing use of biomass. The project participant demonstrated that the amount of biomass waste available in the region was 25% higher than what was needed by the project activity, thereby confirming that no leakage needed to be accounted for.

Monitoring

Monitoring Waste at the Disposal Site before Project Start

Ex ante: In order to calculate potential emissions of methane from waste used by the project using the first order decay model, monitoring shall involve the assessment of the conditions at the SWDS previous to the beginning of the project. The following parameters need to be monitored.

Sampling of Waste Types

- Fraction of methane captured at the SWDS and flared, combusted or used in another manner.
- Total amount of organic waste to be use by the project from disposal (tons).
- Weight fraction of each waste type in the samples collected each year on the SWDS.
- Number of samples collected.

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[246] http://cdm.unfccc.int/methodologies/SSCmethodologies/AppB_SSC_AttachmentC.pdf

Monitoring of LFG Systems installed due to Regulation

If relevant regulations or contractual arrangements exist, monitoring shall be done considering the mandated use of specific collection and flaring systems or the mandate to capture and flare a percentage of the methane generated by the landfill.

Ex post: To estimate baseline emissions, the amount of waste combusted by the project in each year shall me measured and recorded. The biomass and non-biomass carbon content of the waste shall be determined through a representative sampling.

Monitoring of Fossil Share of Waste and Transportation Parameters

Monitoring of project emissions shall consider the following parameters:

- Quantity of auxiliary fuel used;
- Non-biomass carbon content of the waste combusted;
- Total quantity of combustion residues;
- Average truck capacity;
- Electricity consumption and/or generation;
- Distance for transporting the waste in the baseline and the project scenarios;

Alternative Disposal Site for Fresh Biomass Waste Processing

If projects process freshly generated biomass waste, project participants shall demonstrate annually that the amount of waste combusted in the project facilities would have been disposed in a SWDS where no methane recovery would have occurred and where the waste would have been left to decay throughout the crediting period.

5.6 Coal mine methane

5.6.1 Methodologies analyzed

ACM 0008 "Consolidated baseline methodology for coal bed methane and coal mine methane capture and use for power (electrical or motive) and heat and/or destruction by flaring"

5.6.2 Basic concept

Increase of Flaring of Methane from Coal Mines

Emission reductions are calculated as the sum of differences between the methane vented and burned before and after the project and electricity provided by the project and used by the project, multiplied by the power emissions factor, deducting emissions from fossil fuel use in the project and leakage.

$$ER_y = GWP_{CH4} \; X \; (CH_4\,vented_{bl} - CH_4\,vented_{pj} + CH_4\,burned_{bl} - CH_4\,burned_{pj}) \; +$$

ER_y	GWP_{CH4}	$CH_4\,vented_{bl}$	$CH_4\,vented_{pj}$	$CH_4\,burned_{bl}$	$CH_4\,burned_{pj}$
Emission Reductions	CH_4 Global Warming Potential	Methane vented in the baseline	Methane vented in the project	Methane burned in the baseline	Methane burned in the project

$$EF_{grid} \; X \; (El\_Prod_{pj} - El\_Cons_{pj}) - EF_j \; X \; Fuel_{j,\,pj} - Leakage$$

EF_{grid}	El_Prod_{pj}	El_Cons_{pj}	EF_j	$Fuel_{j,\,pj}$	$Leakage$
Emission factor of electricity grid	Electricity production in project	Electricity use in project	Emission factor of fuel j	Use of fuel j in project	Indirect emissions

5.6 .3 ACM0008

Description of the current version of the methodology

Only Methane from operating underground Mines

Applicability conditions: ACM0008 (version 03) is applicable to projects that capture and destroy coal mine methane (CMM) and/or extract coal bed methane (CBM) before mining at currently operating or newly built underground coal mines. It is not applicable to closed mines or to utilization of CBM from seams that will not be mined in the foreseeable future.

Collection and Transport Equipment for CMM

NMHC Emissions only covered if more than 1% of CMM Volume

Project boundary: The spatial extent of the project boundary includes the equipment installed and used for the extraction, compression, and storage of CMM and CBM at the project site, and transport to an off-site user, as well as flares or engines for electricity/heat generation, and the power plants connected to the grid serving the coal mine. Only CBM wells that are within a three-dimensional "zone of influence" of the mined area are part of the project. Within the project boundary, project participants shall only account for CO_2 emissions from the combustion of non methane hydrocarbons (NMHCs), if they represent more than 1% by volume of the extracted coal mine gas.

Baseline Scenario Options

Ex-ante Projection of CMM must be available

Baseline scenario and additionality: The baseline scenario is the most economically viable or the lowest emissions-intensive of the following options: venting, flaring, heat and power generation or feeding into gas pipelines. The option chosen also should not face prohibitive barriers and must be technically feasible to handle CBM and CMM to comply with safety regulations. Data must be available to provide ex-ante projections of methane demand over the crediting period and must be disaggregated according to the phases of methane recovery (CBM prior to mining, underground pre-mining CMM drainage, surface or underground post mining CMM drainage, drainage from sealed goafs before the mine is closed).

Additionality of the project shall be demonstrated by application of the latest version of the "Tool for the demonstration and assessment of additionality" (additionality tool) to the selected baseline scenario.

Emission Reduction based on Difference of GWP of unburnt and burnt Methane

Emission reductions: Methane venting releases 21 t CO_2 per t of methane whereas combustion only releases 2.75 t CO_2 per t of methane. Emissions from flaring are calculated according to the "Tool to determine project emissions from flaring gases containing methane". Methane oxidation factors are taken from the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories as 99.5% for heat and power generation and 98.5% for feeding into gas grids.

Engineering Study for Methane Demand in Baseline Scenario or Statistical Projection based on 5 Year Data

Methane demand for heat generation in the baseline scenario has to be estimated on the basis of an engineering/economic study describing the current distribution system, identifying CMM/CBM users, their consumption rates, expected growth rates of users and gas grid expansion plans. If there is no information on the existing distribution system, a statistical projection based on CMM/CBM availability and thermal energy CMM/CBM usage rates over at least the past five years can be used. If less than five years of data are available, the maximum existing pipeline capacity will be used as proxy for demand.

Day-by-Day Estimate to determine highest Demand for that Day during last 5 Years

"Overlaps", i.e. displacement of thermal methane uses in the baseline scenario by methane use for electricity generation in the project scenario, do not generate emission reductions. To allow day-by-day projection of thermal methane demand, data for the last five years before project start have to be provided. For each day of a year during the crediting period, the highest demand volume for that day during the last five years will determine baseline scenario demand. For example, if on day x of each of the last five years methane uses were 105, 111, 95, 102 and 108% of the mean daily demand of each year respectively, the projected methane demand for day x will be 111% of the mean daily projection of the project year. If daily demand data are not available, monthly data can be used instead.

Definition of "Influence Area", whose CBM Capture and Burning can generate CERs

According to a complex procedure to determine the area influenced by mining where the coal seam is "de-stressed", the share of "eligible" CBM from wells drilled before mining is determined. Only this share is used to calculate CBM-related baseline emissions, while the total CBM volume including the non-eligible share is used to calculate project emissions, to be on the conservative side. CBM capture only generates reductions once the coal seam is mined through …

Leakage due to Displacement of Methane used in Baseline
Leakage due to CBM Seepage from adjacent Seams – 10% Default
Leakage due to increased Coal Production – 10% Default
Leakage due to CER Impact on Coal Prices Currently not calculated, but can be put back on EB Agenda

Leakage consists of four elements. The first is emissions due to "overlaps" as described above, where fossil fuels are now used instead of methane. For the resulting energy shortfall, the energy content is calculated and multiplied by the emissions factor of fuels that would be used to cover the shortfall. The second leakage component is CBM generation which is eligible, but occurring from coal seams outside the de-stressed area, which would happen if the boreholes have no casing and there are no surface boreholes for CBM extraction in the baseline scenario. For this leakage, a default discount of 10% or an ex-ante engineering estimate is to be used. The third component of leakage applies if CMM is ventilated in the baseline scenario. As ventilation in an underground mine cannot transport infinite amounts of methane, CBM/CMM extraction before mining can lead to increased coal production. For this leakage, a default discount of 10% or the share of the additional coal production in total coal production is to be used. The fourth leakage component is very unusual as it wants to address the market impact of CER revenue on coal prices and apply a discount that would capture the coal consumption increase due to reduced market price. This is inconsistent with all other baseline methodologies. For the time being, the fourth component is not to be calculated, as the Meth Panel recommended that the EB should decide after 2-3 years of projects being implemented using ACM 0008 whether it should be revised to reflect price and market impacts.

No ex-ante Monitoring

Ex post Monitoring of Methane Concentration in CMM and Methane burnt

Characteristics of Coal Seams and CBM Wells

Monitoring: Monitoring shall include the following data (only ex-post):

- Amount of CBM/CMM collected, using a continuous flow meter and monitoring of temperature and pressure;
- Methane concentration in extracted CBM/CMM, using a continuous analyzer or with periodical measurements, at a 95% confidence level , using calibrated portable gas meters and taking a statistically valid number of samples;
- MHC concentration in extracted CBM/CMM;
- Electricity, heat and fuel generation and consumption of the project;

- Methane used for electricity and heat generation and methane flared, using a continuous flow meter and monitoring of temperature and pressure;
- Thickness of coal seams, coal density, gas content of coal, borehole location and CBM flow per borehole.

Challenges encountered in the application of the methodology

Flare Efficiency Measurement Problem

According to its methodology revision history, the main challenges encountered in the application of ACM0008 was the measurement of flare efficiency, as the methodology was revised twice to align flare efficiency monitoring with the procedures in other methane capture-related methodologies (see discussion in section 5.4). So far no-ACM 8 specific request for review, revision or clarification has been submitted, which is surprising given the complex features of the methodology. One project (UNFCCC no. 1135) had to make corrections but these only relate to the implementation of the investment test.

Deviation for Methane from non-coal Mines

A request for deviation was lodged in March 2007 for the Beatrix gold mine in South Africa, where methane is coming from unclear sources. The developers argued that the mine's situation was unique and thus would not warrant a specific methodology. The EB rejected the request stating that the methane collected is similar to CBM and that the boreholes would not necessarily be linked to the mined area and thus would not influence the eventual methane emissions in the mined areas. Furthermore, the EB argued that "CDM benefits could not (sic!) generate an incentive to drill additional boreholes near emitting ones where the probability to get another emitting borehole may be high. The existing methodology does not provide any procedures to ensure that this is not the case." Subsequently, the project developer has submitted a new methodology (NM 236).

5.7 Thermal Energy for the User

5.7.1 Methodologies analyzed

Small Scale	AMS-I.C (Thermal energy for the user with or without electricity)

5.7.2 Basic Concept

Category Description

Renewable Heat

This category deals with projects that involve the supply of renewable thermal energy to users and households that displaces fossil fuels usage.

Methodological Concept

Emissions Reductions are Heat Generation times Emission Factor of Baseline Fossil Fuel

Emissions reductions arising from this project type correspond to the emissions that would have been generated to produce thermal energy in the absence of the project. Therefore emission reductions (ERs) are typically calculated as the thermal energy generated by the project (TJ) multiplied by the emission factor (tCO_2/TJ) of the technology used to estimate the baseline emissions (i.e. the technology that would have been used in the absence of the project). Some leakage may need to be taken into account.

ERs	=	$TJ_{project}$	*X*	$(tCO_2/TJ)_{baseline}$	–	*Leakage*
Emission Reductions		Project Thermal Energy		Baseline Emissions per Unit of Thermal Power		Leakage

5.7.3 AMS-I.C

Project Description

Biomass-based Heat Generation

AMS-I.C (version 12) covers various types of projects that use renewable energy technologies to supply thermal energy to individual households or users. Examples of projects include solar thermal water heaters and dryers, solar cookers, energy derived from renewable biomass for water heating, space heating, or drying, and other technologies that provide thermal energy and displaces fossil fuel. Biomass-based co-generating systems that produce heat and electricity are also included.

The most common projects using this methodology produce thermal energy from agricultural residues.

Differentiation between Renewable and Non-renewable Biomass

Box 38: The differentiation between renewable and non-renewable biomass in the baseline

Over the course of the evolution of AMS.I-C, the issue of differentiating between renewable and non-renewable biomass in the baseline was raised a number of times. Reducing the use of non-renewable biomass has been seen akin to avoiding deforestation. As the latter is not eligible under the CDM, projects reducing the use of non-renewable biomass have not been registered since late 2005. The SSC WG01 responded to the first request[281] by explaining that the key issue was to determine whether the biomass used in the baseline was renewable or non-renewable. SSC WG 01 decided not to accept the request, as no definition of renewable biomass existed at the time. Another submission[282] requested that the proposed methods to handle the treatment of leakage and the definition of non-renewable biomass in the baseline be incorporated in the baseline. SSC WG03 also rejected that request and required that references to "non-renewable biomass" as a plausible baseline scenario be deleted in the simplified baseline and monitoring methodologies for selected small-scale CDM project activities (including in AMS-I.C).

Additionally, other requests for revision[283] were submitted to the SSC WG, requesting that the installation of cook stoves be eligible project activities under AMS-I.C. In response, the SSC WG 04 agreed to amendments to two new methodologies not yet approved[284]. While a definition of renewable biomass was agreed upon at EB 23,[285] negotiations are still underway at the COP/MOP level to resolve this matter.

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[247] See SSC_05
[248] See SSC_018.
[249] See SCC_31, SSC_34 and SSC_35.
[250] These methodologies are AMS-I.E – Switch from Non-Renewable Biomass for Thermal Applications by the User – and AMS-II.G – Energy Efficiency Measures in Thermal Applications of Non-Renewable Biomass.
[251] See Annex 18 of the EB23 Meeting Report.

Applicability conditions

Definition of Small-scale Threshold for this Project Type

Indications for specific cases are:

- The thermal generation capacity shall be less than 45 MW, when specified by the manufacturer.
- For co-fired systems, the aggregate installed capacity (specified for fossil fuel use) of all systems affected by the project shall not exceed 45 $MW_{thermal}$. Cogeneration projects that displace/avoid fossil fuel consumption for the production of thermal energy (e.g. steam or process heat) or electricity shall use this methodology. The capacity of the project in this case shall be the threshold for thermal energy production, i.e. 45 $MW_{thermal}$.
- In the case of projects that involve the addition of renewable energy units at an existing renewable energy facility, the total capacity of the units added by the project should be lower than 45 $MW_{thermal}$ and should be physically distinct from the existing units.

Co-firing with Fossil Fuels possible, but total Plant Size counts for Threshold

Box 39: The definition of the project boundary for co-fired thermal systems

Some requests for revision regarding the definition of project boundary were submitted with regards to the early versions of the AMS-I.C.[286] In cases of fossil fuel fired thermal systems co-fired with renewable biomass, it was unclear whether the 45$MW_{thermal}$ limit was imposed for the system as a whole or only for the biomass component of the project. It was decided that the total capacity of the existing unit (specified for using fossil fuel) will be used for considering the eligibility, and not the capacity when using biomass. SSC WG 03 decided on an amendment to clarify that for large systems consisting of many thermal generation units (boilers), in which only parts were affected by the proposed project activity, the combined capacity of the boiler(s) affected by the project must be smaller than 45 $MW_{thermal}$. This led to version 6 of the AMS-I.C.

Capacity Addition qualifies for separate Calculation of Threshold, if physically distinct

Box 40: The inclusion of capacity addition or retrofit activities

SSC WG 08 recommended that guidance on capacity addition and retrofit activities in a facility under AMS-I.C be revised to be consistent with revisions brought to AMS-I.D. AMS-I.C originally specified that "Project activities adding renewable energy capacity should consider the following cases: 1) adding new units; 2) replacing old units for more efficient units. To qualify as a small scale CDM project activity, the aggregate installed capacity after adding the new units (case 1) or of the more efficient units (case 2) should be lower than 45 $MW_{thermal}$." From version 9 onwards, it was clarified that "the total capacity of the units added by the project should be lower than 45 $MW_{thermal}$ and should be physically distinct from the existing units."

[252] SSC_022 and SSC_023.

PoA only applicable for Biomass Residues or dedicated Plantations

Applicability conditions under a Programme of Activities (PoA): In case of a small-scale PoA where the limit of the entire PoA exceeds the limit for small-scale CDM projects described above, the applicability of the methodology is limited to small-scale CDM Programme Activities (CPAs) that use either biomass residues only or biomass from dedicated plantations complying with the applicability conditions of AM0042[253].

Project boundary

The project encompasses the physical, geographical site of the renewable energy generation.

Baseline Scenario and Additionality

Baseline Scenario only vaguely defined

For renewable energy technologies that displace emissions from technologies using fossil fuels: The simplified baseline is the fuel consumption of the technologies that would have been used in the absence of the project.

Detailed List of Baseline Scenarios for Cogeneration Plants

For cogeneration projects: One of the four following baseline scenarios can be used, depending on the technology that would have been used to produce the thermal energy and electricity in the absence of the project:

a) Electricity is supplied from the grid and steam/heat is produced using fossil fuel;

b) Electricity is produced in an onsite power plant (with a possibility of export to the grid) and steam/heat is produced using fossil fuel;

c) A combination of (a) and (b);

d) Electricity and steam/heat are produced in a cogeneration unit, using fossil fuel.

Cogeneration included according to requests for Clarification

Box 41: The inclusion of cogeneration project activities

In the early stages of development of AMS-I.C, confusion arose with regards to which methodology should be used for cogeneration project[288]. SSC WG 09 eventually revised some small-scale methodologies (including AMS-I.C) to include additional guidance on cogeneration project activities. These revisions were included in AMS-I.C version 10.

The inclusion in AMS I.C of a procedure for calculating emissions where cogeneration from fossil fuels is the baseline broadened its applicability. This clarified that cogeneration projects displacing/avoiding fossil fuel consumption in the production of thermal energy (e.g. steam or process heat) and/or electricity shall use this methodology.

Retrofit generates CERs for remaining Lifetime of retrofitted Plant

For projects that involve the addition of renewable energy units at an existing renewable energy production facility: For projects that add renewable energy generation units to an existing facility, the baseline scenario corresponds to the fuel consumption of the technologies that would have used the energy produced by the added units. For projects that seek to modify or retrofit an existing facility, the baseline scenario corresponds to the thermal energy supplied by the existing facility, before the modification

253 The complete list of applicability conditions for projects under a PoA may be found in Annex I of AMS-I.C, titled "Applicability conditions and guidance on leakage below concerns Project activity under a programme of activities".

254 See e.g. SSC_97.

or retrofit. This baseline holds for the period of time that the existing facility would have operated before being replaced or retrofitted as a matter of course. Beyond that period, the project emissions are considered to be the baseline emissions.

Project participants may also use other additionality demonstration methods, e.g. the investment analysis stipulated in the additionality tool, in addition to the barrier analysis.

Baseline Emissions

Baseline Emissions: Fuel Consumption of Baseline Scenario Technology times Emission Factor

For renewable energy technologies that displace emissions from technologies using fossil fuels: The baseline emissions are to be calculated as the fuel consumption of the technologies that would have been used in the absence of the project multiplied by the emission factor of the fossil fuel displaced. IPCC default values for emission coefficients may be used.

Differentiation according to Type of Cogeneration Plant

For cogeneration projects: When electricity is produced, the baseline emissions are to be calculated as the amount of electricity produced with the renewable technology multiplied by either 1) the CO_2 emission factor per unit of energy of the fuel that would have been used in the baseline plant divided by the efficiency of the captive plant or 2) the CO_2 emission factor of the grid to which the electricity is supplied. When steam/heat is produced using fossil fuels, the baseline emissions are calculated as the net quantity of steam/heat supplied by the project multiplied by the CO_2 emission factor per unit of energy of the fuel that would have been used in the baseline plant divided by the efficiency of that plant. When electricity and steam are produced in a cogeneration unit using fossil fuel, the baseline emissions are calculated as the net quantity of steam/heat supplied by the project plus the amount of electricity produced with the renewable technology multiplied by a conversion factor, multiplied by the CO_2 emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant divided by the total efficiency of that plant.

If Project adds Capacity, Impact on Resources available to existing Capacity has to be assessed

For projects that involve the addition of renewable energy units at an existing renewable energy production facility: Baseline emissions are calculated as the fuel consumption of the technologies that would have been used in the absence of the project multiplied by the emission factor of the fossil fuel displaced. The potential for the project to reduce the amount of renewable resource available to, and thus thermal energy production by existing units must be considered in the determination of baseline emissions, project emissions, and/or leakage, as relevant.

Retrofit: Average historical Emissions of retrofitted Plant

For projects modifying or retrofitting an existing facility, the baseline emissions are calculated as the average historical emissions of the existing facility, before the modification or retrofit. To calculate the period over which this baseline is valid, it is necessary to evaluate the time at which the thermal energy facility would have been replaced or retrofitted in the absence of the project.

Technical line losses are to be included in calculation of Project Emissions but not in the Baseline Emissions

> **Box 42:** The consideration of technical line losses in the baseline
>
> An amendment of various small-scale methodologies was requested to account for technical line losses in cases where electricity is the baseline[289]. The request claimed that the baseline was not accurately estimated under AMS-I.C and that AMS-I.C was not consistent with all methodologies of category II that refer to AMS-I.D for the calculation of the grid emission coefficient. SSC WG 08 rejected this request explaining that the combined margin approach of AMS I.D was designed to estimate the emission factor of a hypothetical plant replaced by the project, and is therefore meant to estimate a counterfactual scenario.
>
> In response to a similar request[290] SSC WG 12 reiterated that CDM methodologies are meant to produce conservative estimates and accordingly, technical line losses should be included in the calculation of projects emissions and excluded from baseline emission calculations. Should it be possible to demonstrate that the project activity has no significant impact on the grid, then the calculation of baseline emissions could include a consideration for technical losses. In all other cases, a conservative approach to baseline emissions calculation should be adopted.

Project Emissions

Project emissions are typically assumed to be zero.

Leakage Calculation, if Reuse of replaced Equipment

Leakage

Leakage is to be considered if the energy generating equipment is transferred from another activity or if the existing equipment is transferred to another activity.

PoA Leakage

No Shift to Fossil Fuels elsewhere

Leakage under a PoA: There is a risk of leakage as the PoA may divert biomass residues from other uses, which may subsequently lead to an increase in emissions from fossil fuel combustion or other sources. If biomass residues are co-fired in the project plant, project participants shall demonstrate that the use of the biomass residues does not result in an increase in fossil fuels use or an increase in GHG emissions elsewhere.

Monitoring

Metering of Sample of Projects

In cases where baseline emissions are calculated using the energy produced multiplied by an emission factor, monitoring shall be conducted by metering the energy produced by a sample of the systems.

In the case of cogeneration projects, monitoring shall be done by metering the thermal energy and electricity generated.

Systems generating less than 5 CERs/ year only need to record Operating Hours

If the emissions reduction per energy production system is less than 5 tonnes of CO_2 a year monitoring shall consider:

i. Recording annually the number of systems operating; and

ii. Estimating the annual hours of operation of an average system.

Projects using biomass or biomass and fossil fuel need to monitor the following additional items:

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255 See SSC_71.

256 See SSC_115.

- For biomass-fired projects, a specific fuel consumption of each type of fuel used (biomass or fossil) should be specified ex-ante. The consumption of each type of fuel shall be monitored.
- If fossil fuel is used, the thermal energy or the electricity generation metered should be adjusted to deduct thermal energy or electricity generation from fossil fuels using the specific fuel consumption and the quantity of fossil fuel consumed.

Monitoring of all Biomass Types

- If more than one type of biomass is consumed each type shall be monitored separately.

Lower Value of Energy measured and Energy calculated from specific Fuel Consumption

- The amount of thermal energy or electricity generated using biomass fuels shall be compared with the amount of thermal energy or electricity generated calculated using specific fuel consumption and the amount of each type of biomass fuel used. The lower of the two values should be used to calculate emission reductions.

PoA requires Monitoring of scrapped Equipment

Monitoring under a PoA:

- The number of the distributed and scrapped equipment shall be monitored; and
- Biomass power projects shall follow the general guidance for leakage in small-scale biomass project activities or the procedures given in AM0042.

5.8 Biomass power generation

5.8.1 Methodologies analyzed

Large Scale	ACM0006 (version 6) "Consolidated methodology for electricity generation from biomass residues"

5.8.2 Basic concept

Category description

New of retrofitted Biomass Power Generation

This category includes projects that aim to produce electricity or thermal energy from the combustion of biomass residues. Projects may be developed on sites where no power generation occurs or on sites where a fossil fuel or biomass residues fired plant already exists. Retrofits are also eligible under this category, as well as projects converting an existing fossil fuel fired plant to a plant fired by biomass residues.

Methodological concept

Emission Reduction: Energy produced by Project times Emissions Factor of Baseline Fossil Fuel Power Plant

Emission reductions for activities falling under this category correspond to the difference between the emissions arising from the production of biomass residues-fired energy (electricity and/or heat) and the emissions that would have otherwise arisen from the production of energy by a reference power generation baseline scenario *inter alia* an on-site fictional or existing fossil fuel fired power plant or by a less efficient fossil fuel or biomass residues – fired power plant had the project not occurred.

Methane Reductions from Avoidance of anaerobic Decay can be claimed

Project proponents may decide to account for the CH_4 emissions mitigated by the project provided that it contributes to reducing CH_4 emissions arising from the uncontrolled burning or aerobic or anaerobic decay of the biomass residues the project will use. Net emission reductions are measured as follows:

ER_y	=	$ER_{heat,\ y}$	+	$ER_{electricity,\ y}$	+	$BE_{biomass,\ y}$	–	PE_y	–	L_y
Emissions reductions of the project activity		Emissions reductions from heat generation		Emissions reductions from electricity generation		Emissions avoided from biomass decay or burning		Project emissions		Leakage

5.8.3 ACM0006

Project description

Eligible Project Types

Projects eligible under ACM0006 are those that propose the generation of energy (electricity and/or heat) from biomass residues. More specifically, these include: (i) the installation of a new biomass residue fired power plant where no power generation occurs (greenfield power plant), (ii) the installation of a new biomass residue power plant to replace, or operate next to, an existing power plant fired with fossil fuels or with the same type of residue the project proposes to use, (iii) the retrofit of an existing plant or the replacement of an old plant by a more efficient one and (iv) the replacement of fossil fuel by biomass residues in an existing power plant.

Applicability Conditions

Definition of Biomass Residues

No Municipal Waste

ACM0006 may be used for projects producing energy – including cogeneration plants – using biomass residues. Biomass residues are defined as "by-products, residues and waste from agricultural, forestry and related industries. They do not include municipal waste or other wastes that contain fossilized and/or non-biodegradable material."

Biofuel has to be predominant

No Increase of Production Process that generates Residues

Projects may rely upon a power plant located in an agri-industrial plant from which the biomass is sourced or upon an independent power plant sourcing its biomass residues from the regional area or market. Additionally, several conditions must be fulfilled in order to apply ACM0006. For instance, no other biomass types than biomass residues may be used to fire the project power plant. The residues should be the predominant fuel of the project, though some fossil fuels may be co-fired. Projects using residues from a production process (e.g. sugar cane or wood residues coming from a sawmill) should not lead to an increase in production or trigger a change in the production process of the raw material from which the residues are derived. Finally, the preparation of the biomass residues should not be energy intensive.

A handful of projects have submitted requests to include new baseline scenarios, with variable level of success (see following section on baseline and additionality). Other projects may be diverting too much in terms of their methodological approach and have been recommended by the MP to apply similar, yet different methodologies than ACM0006 (see Box 43).

Revision to include Heat only Boilers rejected

> **Box 43:** Fuel switch projects involving heat generation only
>
> A request for revision[291] suggested that a project involving a fuel switch from fossil fuel to biomass residues in a heat-only boilers be eligible under ACM0006. The MP explained that the project was not eligible because it is not appropriate to assume that only fossil fuel would be used in the baseline scenario, more so considering that historically, boilers have generated heat using biomass residues. Additionally, the proponent mentioned that the project could use different types of biomass than biomass residues throughout the crediting period, which was inconsistent with ACM0006. The MP recommended the project proponent to consider using AM0036, which had specifically been created for fuel switch from fossil fuel to biomass residues in heat-only boilers (the methodology had not been approved when the request had been submitted). However, the MP warned that, like ACM0006, AM0036 did not allow the use of biomass types other than biomass residues.

Project Boundary

Project Boundary includes Plant, Transport and Waste Disposal Site

The project boundary shall include all the sites and transportation routes where emissions arise as a result of the project. These include the site where the power plant or retrofit is implemented, the site where the biomass residues are produced, the transportation routes between the site(s) where the biomass residues are sourced and the project's power plant, and the site(s) where the biomass residues would have been dumped or left to decay in the absence of the project. The project boundary should also include all the power plants connected to the grid the project activity is connected to. To determine the spatial extent of the project's grid and calculate the project's build margin (BM) and operating margin (OM), project proponents should refer to the latest version of ACM0002 (see section 5.2.3).

Baseline scenario and additionality

Three Elements of Baseline Scenario: Power, Waste Treatment, Heat

In determining their project's baseline scenario, project proponents should first identify all credible alternatives with respect to:

1. How power would be generated in the project area in the absence of the project;
2. The treatment of the biomass residues in the absence of the project;
3. How the heat the project proposes to produce would be generated in the absence of the project (specific to cogeneration power plants).

Matrix of 20 Baseline Scenario Options

ACM0006 provides several plausible alternative baseline scenarios for each of the aforementioned categories. Upon identifying the most plausible baseline alternatives for power generation, heat generation, and biomass handling, project proponents should identify all realistic combinations of the three. Project proponents must then verify whether the identified combined baseline scenario is included in the list of applicable baseline scenarios found in ACM0006. In total, ACM0006 (version 6) proposes 20 different combined

[257] See AM_REV_0019

baseline scenarios[258]. A wrong selection of a baseline scenario may lead to critical problems during the development of the PDD (see box 44). If the project demonstrates that its combined baseline scenario is part of the list provided by ACM0006, then it may use this methodology. Otherwise, they may submit a new baseline scenario to the MP for approval (see box 45). In addition, project proponents should check whether the procedures to calculate the emissions reductions stemming from the project apply to the project's context. If the calculation methods provided by ACM0006 do not fully suit the context of the project, a revision or deviation should be requested.

Withdrawal of Project due to wrong Baseline Scenario

Box 44: Inaccurate assessment of the baseline scenario

In the case of project 0552, "16 MW Bagasse based cogeneration plant", the EB observed contradictions between the chosen baseline scenario – "existing unit(s) are only fired with biomass" – and the proposed project scenario – "cogeneration plant uses bagasse as fuel … along with some coal co-fired". In turn, the project was not able to use the approved methodology and was subsequently withdrawn from the CDM pipeline.

[258] For a complete listing of applicable combined baseline scenarios, please refer to page 8 of ACM0006 version 6.

Submission of further Baseline Scenarios

Two Requests for Revision by same Developer due to constant Changes in Baseline Situation

New Combination of Accepted Scenario Elements

Box 45: Issues related to the inclusion of new baseline scenarios

Since the consolidation of ACM0006, several requests for clarification and revision have been submitted to the MP asking for the inclusion of new baseline scenarios in ACM0006. Only a handful of these are presented here as examples of classic requests. "Revision of ACM0006 to reflect a baseline scenario where heat generation occurs with both biomass and fossil fuels in boilers"[293] was submitted to the MP requesting the inclusion of a new combined baseline scenario where electricity generated would be supplied to the grid and heat would come from a combination of different sources, including a black liquor fired cogeneration plant, biomass heat boilers, and fossil fuel heat boilers. The MP recognized the project[294] met the basic eligibility requirements of ACM0006 and recommended including the new baseline scenario (scenario 16), leading to an EB decision to revise the methodology accordingly. Interestingly, the same project proponent later submitted a request for revision[295] after having realized that the combined baseline scenario it had requested did not apply anymore to the project's situation. The proponent explained that heat was diverted to the project plant by one out of the five existing heat boilers on the project site (either fired by fossil fuels and/or biomass residues), and requested whether these pre-project boilers could be co-fired at times even after the implementation of the project activity. The MP argued that the electricity produced by the new biomass fired plant could reduce the necessity of using fossil fuel in these existing co-fired boilers, hereby displacing fossil fuel generated electricity. However, the methodological rationale of ACM0006 assumes that the increase in energy generation from biomass residues will contribute to displace fossil fuel generated electricity only from the grid and not from existing plants on the project site. Based on this premise, the MP rejected the request.

Another interesting case arose from a request for clarification inquiring whether two combinations of baseline scenarios could be paired to suit the requirements of a project with two boilers and one turbo generator[296]. The MP reacted favorably to the request, arguing that though ACM0006 does not allow the combination of multiple baseline scenarios, the proposed project proved to be a rather unique case and that the approach proposed by the project proponent for monitoring and calculating emissions reductions was appropriate. Because of the particular character of the project, the MP did not recommend a revision to ACM006 but rather encouraged the project proponent to request a deviation.

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259 See AM_CLA_0012

260 For more details about the underlying project, see NM0098 "Nobrecel Fossil-to-Biomass Fuel Switch Project in Brazil".

261 See AM_REV_0048

262 See AM_CLA_0042

Retrofit for Improvement of Efficiency or Increase in Capacity?

> **Box 45:** Issues related to the inclusion of new baseline scenarios *(continued)*
>
> In addition, several cases where submitted for projects that aim to improve the efficiency of an existing facility[297]. The first request arose from an agri-industrial facility that wants to claim emissions reductions by improving its energy production and consumption. The MP rejected the request on the premise that the proponent assumed in its calculation that an increase in the project's own energy efficiency – whether assessed by an increase in the amount of electricity directed to the grid or by an increase in the amount of biomass residues used by the plant – was necessarily triggered by the CDM activity. The MP argued that a decrease in production at the facility would reduce the facility's need for electricity and increase the quantity of it may export to the grid. Alternatively, an increase in production at the facility could lead to an overall increase in energy production, subsequently increasing the electricity exported to the grid. In both cases, the MP considered that such potential increase of exported electricity would arise without the input of the CDM component, and therefore the project proponent should not be allowed to claim CERs from the additional electricity exported to the grid.
>
> Another request for an energy efficiency project was later rejected by the MP on similar grounds. First, though one of the project's aims was to reduce its own energy consumption, it did not explicitly specify what measures would be undertaken to reduce its heat and electricity. Additionally, the project proponent did not provide an adequate procedure for assessing its baseline scenario throughout the crediting period. The proponent assumed that its energy intensity demand would not change over time, without considering the eventual necessary replacement of the existing equipment leading to a reduction in the project's own energy need.

Combined Additionality Tool to be used

To prove additionality, project proponents should perform a thorough additionality test as per the latest version of the *"Combined tool to identify the baseline scenario and demonstrate additionality"*. Similarly, ACM0006 recommend proponents to use the same Tool to properly assess their baseline scenario.

Baseline emissions

Baseline emissions include two main sources: (i) the CO_2 emissions arising from fossil fuel consumption by existing electrical power plants on the site of the project or by electrical power plants connected to the grid that the project contributes to displacing; and (ii) the CO_2 emissions attributable to the production of the thermal energy the project contributes to displacing.

Methane Emissions can be covered in Baseline

In cases where the most plausible baseline scenario for the biomass residues used by the project is that the biomass residues would be dumped and left to decay in an aerobic or anaerobic state or burned in an uncontrolled manner, project proponents may choose to account for the CH_4 emissions mitigated by the project through the diversion of the biomass residues.

Different Baselines required for different Types of Residues

Issues specific to projects using different types of biomass residues: Projects that use different types of biomass residues or similar biomass residues but from difference sources should develop separate baseline calculation for each type of biomass residue. Similarly, biomass residues with different end uses in the absence of the project should also be treated as different residues and be accounted for separately in the baseline assessment.

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[263] See AM_REV_0006, AM_REV_0015, AM_REV_0044, and AM_REV_0062

Heat only Projects

Box 46: Calculation issues arising from proposed new baseline scenarios

A request for revision[298] enquired about the inclusion of a baseline scenario for projects that only generate heat and no power. Though the proponent proposed several modifications to the phrasing of the methodology to reflect its inquiry, he failed to properly modify the emissions reductions equations accordingly throughout the methodology. The MP rejected the proponent's request for modification primarily because calculation protocols were not revised adequately. Additionally, the MP argued that ACM0006 was already a complex methodology and therefore could not be altered significantly in order to include projects that only generate heat. Rather, the MP invited the project proponent to submit a new methodology based on elements of ACM0006 and ACM0009.

Baseline Scenario Greenfield Captive Power Plant

Another interesting request[299] sought the approval of a new baseline scenario involving the construction of a greenfield biomass residue power cogeneration plant and where electricity would be produced by a new fossil fuel power plant in the absence of the project and part of the biomass residues would be left to decay. The MP judged the proposed project to be in line with ACM0006 yet it did not find adequate the approach to measure the CO_2 emissions arising from displacement of electricity. A second request for revision was subsequently submitted by the project proponent[300], which lead to the approval of the project's baseline emissions calculations.

Project emissions

Methane Emissions to be calculated for Project if covered in Baseline

Project emissions stem from two main sources: (i) The CO_2 emissions attributable to the operation of the project, whether the project is connected to a stationary source of energy or to the grid; and (ii) the CO_2 emissions arising from the transportation of biomass residues from the source to the project's power plant. CH_4 emissions released through the combustion of biomass residues for energy production must also be accounted if CH_4 emissions were included in the baseline scenario. Project proponents should also account for the CH_4 emissions arising from the anaerobic degradation of the wastewater used in cases where the biomass residues are treated.

Leakage

The main potential source of leakage for activities under ACM0006 is the increase in CO_2 emissions arising from the consumption of fossil fuel due to the diversion of the biomass residues from other uses as a result of the project.

Leakage to be covered if Biomass Residues not used in Baseline Scenario

If the most likely baseline scenario is that the biomass residues would have been used for energy generation, then no leakage needs to be accounted for. However, if the baseline scenario is the decay or uncontrolled burning of the biomass residues without energy production, then proponents must demonstrate that the use of the biomass residues does not lead to an increase in fossil fuel consumption elsewhere. To do so, project proponents must demonstrate that there is a sufficient regional supply of the biomass residues type it proposes to use to avoid a shortage that could lead to a switch to fossil-fuel fired processes outside the project boundary.

264 See AM_REV_0008
265 See AM_REV_0032
266 See AM_REV_0047 "Request to include biomass project supplying power and heat directly to the user instead of electricity grid"

Monitoring

Monitoring ex ante of Baseline Scenario Plant, Grid Emissions Factor and Emissions from Biomass Burning

Ex ante: Depending on the combined baseline scenario, the following parameters should be monitored *ex-ante* to determine the emissions that would arise without the project:

- The quantity of electricity (in MWh) produced by the grid or by less efficient plants (than the project power plant) fired with the same biomass residues as the project prior to the implementation of the project.
- The CO_2 emission factor of the electricity displaced by the project.
- The emissions reductions due to the displacement of heat (measurements directives vary depending on which baseline scenario is applicable).
- Emissions due to the uncontrolled burning of anthropogenic sources of biomass residues (if applicable to the chosen combined baseline scenario).

Monitoring ex post of Biomass used differentiated according to Types, Transportation

Ex post: The following parameters should be monitored continuously or periodically (as specified in ACM0006) upon the commissioning of the project:

- Quantity of biomass residues by type combusted in the project plant during any given year;
- Quantity of biomass residues by type that has been transported to the project site
- during any given year;
- Moisture content of the biomass residues;
- Quantity of dry biomass residue combusted by all power plants at the project site during any given year;
- CH_4 emission factor for the combustion of the biomass residues (if CH_4 emissions are accounted for in the baseline);
- Average round trip distance (from and to) between the various biomass residues supply sites and the project site;
- Number of round trips to transport the biomass to the project site;
- Average loads of biomass residues brought to the power plant;
- Fuel consumption of the trucks used to transport the biomass residues to the project site;
- Average CO_2 emission factor of the trucks used to transport the biomass residues to the project site;
- Quantity of electricity consumed by the project during any given year;
- CO_2 emissions factor of the grid during any given year;
- Quantity of fossil fuel combusted by the project power plant during any given year;
- Quantity of fossil fuel combusted for other purposes than the project during any given year;
- The CO_2 emission factor of the fossil fuel used for the project;

- Quantity of steam diverted from adjacent boilers to operate the project power plant;
- Average net efficiency of the steam plants from where steam is diverted to feed the project power plant;
- Net quantity of electricity produced by the project power plant during any given year;
- Quantity of electricity produced by the fossil fuel fired captive power plants on the project site as identified in the baseline scenario;
- Quantity of electricity produced by power plants fired by the same biomass residue at the project site, including the project power plant and all previously existing power plants;
- Quantity of heat generated by the project power plant in any given year;
- Total quantity of heat in all cogeneration power plants fired by the same biomass residue at the project site, including the project power plant and all previously existing cogeneration power plants;
- Net calorific value of all biomass residues used by the project;
- Net calorific value of the fossil fuel used;
- CH_4 emission factor for the uncontrolled burning of the biomass residues used by the project activity (if applicable);
- Average net efficiency of the boiler that would generate heat had the project activity not occurred;
- CO_2 emission factor of the most carbon intensive fossil fuel used in the host country;
- CO_2 emission factor for the fossil fuel used by the captive power plant identified in the baseline scenario (if applicable)

Availability of Biomass Residues to be monitored

Additionally, project proponents must provide evidence that the biomass residues used by the project would not be collected or utilized in the absence of the project. Proponents must also be able to assess the quantity of biomass residues being used in the project's region, the total quantity of biomass residues available, and whether or not there is a supply surplus of a sufficient size to satisfy the project's needs.

6. Conclusions

The rules of the CDM are constantly evolving through a complex interaction between several rule-making entities. Framework rules that are stable have been defined by the Kyoto Protocol and the Marrakech Accords. On the other hand, the EB and its panels and working groups decide according to the immediate requirements of the CDM process. With the increase of submission of methodologies and CDM projects, the volume of decisions has increased. These decisions are not presented in a clear, formal way, but as elements in and annexes to the EB's meeting reports as well as in occasional guidance documents. While some case law is developing, the EB occasionally revises or even withdraws previous decisions.

The COP serves as link between the framework level and the day-to-day decisions. However, it is reluctant to take "technical" decisions. Sometimes, disagreements persist between the COP and the EB, which lead to iterative admonitions of the COP to the EB.

Over time, the EB's requirements for application of baseline and monitoring methodologies have been strengthened and the key determinants of additionality testing are better understood. The consolidated additionality tool has become the de facto standard of additionality determination. Data used for the investment test and argumentation about barriers are increasingly sophisticated and referencing improves.

While the monitoring plan was initially not seen as a key element of the PDD, it has become its cornerstone. A credible, redundant management structure for monitoring and an emphasis on choice of adequate measurement equipment characterise good PDDs. A challenge is still an objective definition of quality assurance and – control procedures.

One area where the EB has so far not been able to provide adequate incentives and rules relates to validation. So far, no DOE has been suspended. Despite increasing evidence of validator failures, the rules remain surprisingly fluid. Even if a project is rejected, there will not be an automatic spot check of the DOE even if DOE performance is in doubt.

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