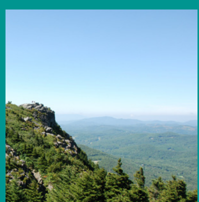
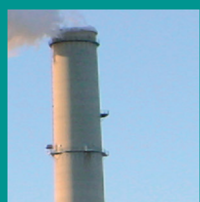
Case Studies of Greenhouse Gas Emissions Offset Projects Implemented in the United Nations Clean Development Mechanism

Learning by Doing and Implications for a Future United States Offsets Program

December 2011





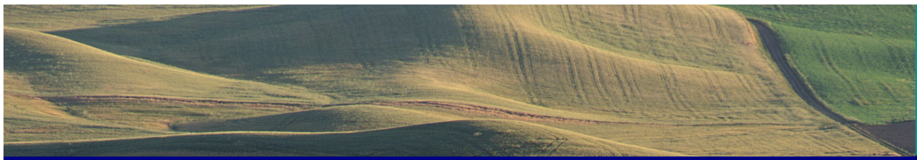


Table of Contents

This paper was written by Robert Youngman, Richard Rosenzweig and Rina Cerrato of Natsource LLC, and Adam Diamant of the Electric Power Research Institute (EPRI).[1]

1. Introduction

This paper describes case studies of greenhouse gas (GHG) emissions offset project activities undertaken within the United Nations Clean Development Mechanism (CDM) program.[2] The CDM was established in Article 12 of the Kyoto Protocol (KP) and has been operating since 2004 when the first CDM offset project was approved or "registered." We have chosen to focus on the CDM in this paper because it is the largest offset program in the world, and has become the benchmark against which other offset programs are evaluated in terms of their design and performance.

Legislation to address climate change by creating an economy-wide GHG or carbon dioxide (CO_2) cap-and-trade program in the U.S. could impose significant emission reduction requirements on the electricity sector and the economy as a whole.[3] To manage GHG allowance prices and the overall cost of the program, firms covered under a cap-and-trade program (covered sources) are expected to need access to large quantities of domestic and international offsets, particularly in the early years of a new GHG reduction program. This is the case because there are limited opportunities to significantly reduce GHG emissions cost-effectively within covered sectors in the U.S., and key new technologies that can reduce GHG emissions need time to be further developed, and are not likely to be economically competitive in the near term.

This paper is designed to communicate key lessons learned from the implementation of different types of GHG emissions offsets projects in the CDM to policy makers in the U.S. who may be interested in developing national, regional or state-based GHG offsets programs. This paper also is designed to provide important insights to entities interested in developing offset projects, and firms that may face climate-related regulations now and in the future and may be interested in developing or buying offsets as an element of their compliance strategies. These insights will help offset project developers and potentially regulated parties to better understand and evaluate the risks of engaging in offsets-related project development and transactions, and to develop more effective market engagement strategies.

The CDM was created to assist developing country Parties (i.e., nations) to achieve sustainable development, to contribute to the ultimate objective of the United Nations Framework Convention on Climate Change (UNFCCC) to stabilize GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system, and to assist industrialized Parties in achieving compliance with their national GHG emission reduction targets. The CDM has stimulated billions of dollars in investment in offset projects in the developing world. By the end of the first KP commitment period in December 2012, the CDM is expected to have issued 1.1 billion offset credits, or Certified Emissions Reductions (CERs) as they are called formally in the CDM.[4] In light of these achievements, many observers believe the CDM has contributed to achieving significant emission reductions in developing countries and important learning which will inform future climate policy development. However, some critics have argued that many CDM offset projects are not "additional" because they would have been implemented without the incentives created by the CDM, and that these projects do not reduce GHG emissions or contribute to sustainable development.

Additional background information on the CDM project approval and credit issuance cycle, and related challenges that have arisen in the CDM can be found in several other recent EPRI publications.[5]

1.1 Benefits of offsets

Offsets are emission reductions created by projects and activities at emission sources, and in economic sectors, not covered by a GHG emissions trading program's fixed cap. These sources and activities may be located either within or outside the geographic jurisdiction of the trading program. The amount of emissions reductions attributable to a specific offset project or activity typically represents the difference between "business-as-usual" (BAU) emissions and actual or calculated emissions following implementation of the offset project.

GHG emissions offsets enable emission sources required by legislation or regulation to reduce their emissions to access and substitute emissions reductions from a broad array of sources, sectors and geographies not covered by the program. These emission reductions may be available at a lower cost than those that can be achieved within covered sectors. As such, offsets can effectively add to the supply of emissions reductions available in the market, potentially reducing allowance prices. In the absence of offsets, emission reductions would have to be achieved entirely within the assets owned by entities covered under the cap-and-trade program. Today, offsets are transacted in both "compliance" and "voluntary" carbon markets (see Box 1).

Because offset programs increase the total quantity of compliance instruments available for use by covered sources, the environmental integrity of the program can be maintained only if offsets are granted exclusively to activities that are *additional* to BAU activities. If BAU activities are allowed to generate offsets, than actual emissions may increase above the level set by the emissions cap, adversely impacting the environmental integrity of the program. To address this concern, offset programs incorporate design elements intended to ensure offsets only are granted to activities that are additional.

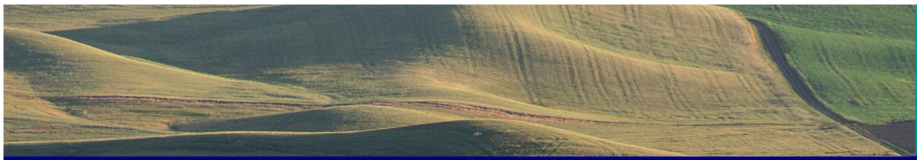
Box 1: Compliance and Voluntary Carbon Markets

GHG emission offsets are transacted in both "compliance" and "voluntary" carbon markets. In compliance markets, the creation and use of offsets is authorized by government rules. Typically these rules define eligible offset activities, additionality criteria, and requirements related to permanence, monitoring, verification and reporting, offset credit issuance and other key details. Existing compliance offsets programs include the United Nations CDM program, and the California Air Resources Board (ARB) offsets program developed as part of California's recently adopted GHG-cap-and-trade program. Once created, compliance-quality offsets can be used by firms regulated under a cap-and-trade program to comply with emission reduction requirements.

In the "voluntary" carbon market, a variety of non-governmental organizations such as the American Carbon Registry (ACR), the Climate Action Reserve (CAR), and the Verified Carbon Standard (VCS) have adopted standards for the creation and use of offsets as part of their programs. Offsets typically are purchased in the voluntary carbon market to mitigate an unregulated entity's carbon footprint.

In both compliance and voluntary markets, offsets typically are awarded on an ex-post basis after capital has been deployed and the emission reduction activity has been implemented.

Research consistently has concluded that offsets can play an important role in controlling the costs of complying with GHG emissions limits for regulated parties and the economy as a whole. For example, analysis of draft cap-and-trade legislation introduced by Senators Kerry and Lieberman in 2010 conducted by the U.S. Environmental Protection Agency (EPA)[7] estimated that the price of emissions allowances under the proposed cap-and-trade program would increase 34% to 118% if the large quantity of international offsets allowed in the proposed legislation were disallowed or were not developed for some reason.



In addition to research results, practical experience has confirmed that buying offsets has been a more cost effective way for many regulated firms to comply with emission reduction requirements than other compliance options, such as buying emissions allowances or undertaking emission reduction projects within their own assets. Buying emissions offsets has been a key element of compliance strategies employed by European firms required to limit their CO2 emissions under the European Union Emission Trading Scheme (EU ETS)[8], and Japanese firms that agreed voluntarily to achieve CO2 emissions reductions as part of Japan's efforts to achieve its KP emissions target. Many covered entities regulated under the EU ETS reduced their expected compliance costs by buying and using offsets to help meet their compliance obligations. The average price for "primary" CERs (i.e., offsets traded in advance of having secured all necessary domestic and international regulatory approvals) was $13.60 in 2007 and early 2008, compared to an average EU allowance price in 2007 of $26.80.[9] Consequently, buyers of primary CERs that eventually were converted into issued CERs achieved compliance cost savings of approximately 50% relative to the average price of EUAs.

In addition to controlling costs, offsets stimulate environmental improvement and innovation in sectors not usually subject to emission reduction requirements, including forestry and agriculture, thus providing important environmental benefits. Through the market price signal, an offset program creates economic incentives to develop new GHG emission reduction technologies and approaches.

Offsets also can provide a "bridge" to a low-carbon future. Offsets allow covered sources to continue utilizing economic assets until the end of their useful lives, thereby reducing premature retirement of assets and associated cost and competitiveness impacts. The use of offsets to comply with near-term emissions reduction targets also allows firms and society more time to develop, demonstrate and deploy new, innovative lower-emitting technologies like carbon, capture and storage (CCS), advanced high-efficiency coal generation, new nuclear power generation and advanced renewables that will be needed to comply with more stringent emission limits over time. The use of offsets make it possible for covered sources to avoid investing in (and locking-in) new, long-lived assets that may achieve only marginal emissions improvements and increase the costs of GHG control programs.

Offsets also provide opportunities to link global carbon markets. For example, because both the EU ETS and the new Australian carbon mitigation program recognize offsets created by the CDM, these two climate mitigation programs effectively will be linked indirectly once the Australian program becomes operational.

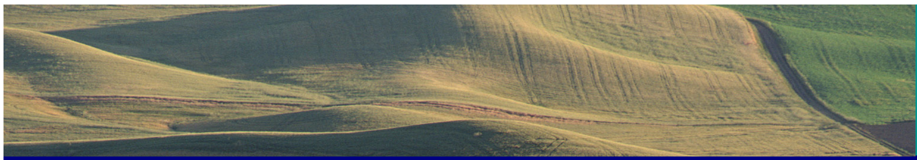
Finally, offsets engage developing countries in the international effort necessary to protect the climate over the long term. This can create economic opportunities for U.S. providers of technologies used in offset projects.

1.2 EPRI perspective

EPRI member companies have a significant interest in the potential role of GHG emissions offsets in climate change policy. As described above, economic modeling of climate legislation and past experience indicates that offsets are a key compliance instrument, and an important source of cost containment in GHG cap-and-trade programs. To date, there have been few efforts devoted to communicating the lessons learned from the CDM and other key existing offset programs. These lessons can help to inform future policy development and potential impacts of choices that policymakers will confront if the U.S. moves forward to develop a large-scale national or regional offsets program. As climate policy continues to evolve at U.S. federal, state, and regional levels, electric companies will need to play an important role in helping to develop offsets policy, and in communicating the role offsets can play in climate policy. This paper is part of EPRI's ongoing efforts to provide timely offset-related information, data, quantitative modeling, and critical analyses to help inform policy and regulatory development.

1.3 Inherent challenges for GHG offset programs

Experience to date in the CDM and other existing offsets programs suggests that offset market participants should expect to face unanticipated challenges when developing offset projects and securing necessary approvals. These challenges can be expected to affect the amount and availability of offset credits, market development, and the overall costs to comply with emission reduction requirements. The case studies described here highlight some of the unforeseen challenges faced by offset developers as they developed, financed and implemented offset projects in the CDM program.



The authors' view that unanticipated challenges are likely to arise in the development and implementation of GHG offset programs is based on our experience in the policy-making process and our market experience working for a company that was one of the largest buyers of GHG emissions offsets in the world on behalf of its investors.[10]

In particular, experience in offset programs has shown it is extremely difficult to prove with 100% confidence that an offset project is additional.[11] Additionality is a central offset program design element that has been and likely will remain contentious, due to the impossibility of proving a counterfactual argument. In addition, designing additionality tests presents a fundamental tradeoff between stringency on one hand (i.e., using strict additionality tests that may prevent approval of non-additional projects, but also may exclude some additional projects), and the desire to stimulate development of a robust market that can create large offset volumes on the other hand (i.e., using less stringent additionality tests that may reduce the potential exclusion of additional projects, but may result in approval of some non-additional projects).

1.4 Offset project risks

Buying offsets has been a key element of compliance strategies employed by covered firms required to limit their CO_2 emissions as part of mandatory emissions reduction programs. Although buying offsets is an attractive compliance option, the case studies that follow illustrate the significant risks associated with developing and undertaking offset projects. These risks can have a negative impact on the ability of offset developers and sellers to deliver the amount of offset credits agreed in contracts with buyers. Consequently, it is important for regulated firms interested in buying offsets as an element of their compliance strategies to understand and be able to assess offset project-related risks.[12]

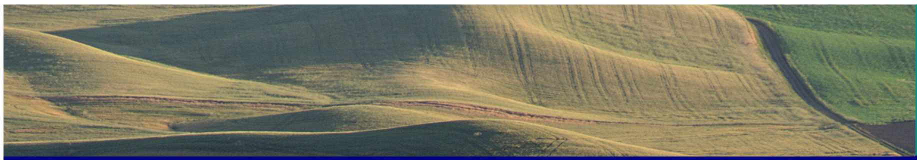
Although offset buyers also confront market risks, including price risk, the discussion below focuses entirely on project-related risks that may affect the amount of offsets expected to be delivered from an offsets project. Natsource identified the categories of offset project risk described below for the purposes of evaluating potential CDM offset projects in which it might invest. Some of these categories of risk may be less applicable – or even irrelevant – in the context of a U.S. national or regional offsets program. In addition, other risks could arise in the future in a U.S. national or regional program that may not be relevant to the CDM.

- **Counterparty or proponent risk –** This is the risk that a counterparty or project developer (or a partner, such as a consultant or technology provider) is unable to implement an offset project as a CDM project (i.e., successfully negotiate the CDM project approval and credit issuance process), or successfully manage the offset project as a result of its credit risk, and/or its lack of carbon market regulatory experience or competence.

- **Country investment risk –** In the CDM context, this category of risk is associated with challenges to an offset project's continuing operations related to the host country's macro-economic, monetary and fiscal policies. It is the risk associated with making any kind of investment in a host country, due to the country's economic policies.[13] This risk is not likely to apply in the context of a future U.S. domestic offset program.

- **Country carbon regulatory risk –** This is the risk that a host country is unable to implement an offset project as a CDM project, and that its carbon related regulatory process and rules may change over the life of an offset project's sales and purchasing contract potentially impairing the project's ability to deliver contracted offsets. This is not likely to be a significant risk in the U.S. context, because U.S. regulatory processes and procedures are much more predictable than those in developing countries.

- **Project carbon performance risk –** This is the risk that changes in the CDM project approval process may adversely affect the ability of an offset project to generate the amount of offsets contracted to be transferred to an offset buyer over the life of the offset project contract. This category includes several subcategories of risk, including additionality risk (i.e., whether or not the project will be able to meet applicable additionality requirements), and baseline identification risk (i.e., the ability to correctly and convincingly identify the emissions that would have occurred in the absence of implementing the proposed project). Such risks likely would be relevant in a future U.S. offset program, because every offset program must establish program and project requirements which necessarily will affect the ability of an offset project to deliver an expected quantity of offsets.



- **Project technology performance risk –** This is the risk that implementation of an offsets project may take longer than planned and/or the technology used in the project may underperform operationally, adversely affecting the ability of a project to create the contracted amount of offsets to be delivered to buyers over the life of a contract. This category of risk also likely will apply to offsets projects developed in any future U.S. offset program.

1.5 Offset project risk management

The following discussion briefly describes mechanisms offset buyers can use to manage the delivery risks associated with developing or undertaking offset projects. These mechanisms include prescreening potential projects, and reducing, transferring or accepting risks associated with offset projects.

- **Prescreening projects –** Buyers can develop a list of criteria to carefully prescreen projects being considered for purchase. Projects that do not meet these criteria are not considered further for investment.

- **Reducing risk –** Buyers can implement a variety of measures to reduce potential delivery risk. For example, buyers can mitigate some project-related risks by developing a diverse offset portfolio in a manner similar to developing a diverse financial investment portfolio. A diverse offsets portfolio could include offsets sourced from different geographic locations, created with different technologies, and purchased from different counterparties. Buyers also can implement credit limits on sellers – i.e., if a seller has a poor credit rating, the buyer can set limits on the quantity of offsets it will buy from the seller and the duration of the purchase contract. Finally, buyers also can require offset sellers to provide collateral to guard against non-delivery of contracted offsets. Such collateral can be in provided in various forms.

- **Transferring risk –** Buyers also can implement measures to transfer risk. For example, buyers can swap “primary” offsets purchased from project developers for less risky compliance instruments such as emissions allowances. Buyers also can enter into “interruptible buyer contracts,” in which the buyer may cancel the contract without penalty under certain circumstances.

- **Accepting risk –** Buyers also can choose to *accept* offset delivery risks. Some examples of measures to accept risk include: (i) establishing reserve margins (e.g., a 20% reserve margin) for a portfolio of primary offsets; (ii) “overbuying” primary CERs to account for potential under-delivery; and, (iii) incorporating “default recovery” provisions in offset purchase agreements.

1.6 Case studies

The following sections of this paper focus on case studies of different types of offset projects developed and implemented in the CDM, including: (i) landfill gas (LFG), (ii) agricultural methane destruction, (iii) waste heat recovery, (iv) afforestation and reforestation (A/R), (v) renewable energy, and (vi) HFC23 destruction.

Each case study identifies key challenges confronted by offset project developers as they attempted to develop offset projects capable of securing approval by the CDM and creating CERs. The case studies provide examples of specific issues that have affected the delivery of offsets from specific types of CDM projects. The case studies highlight technology-specific implementation issues that in some cases may be familiar to entities engaged in the CDM offset market, and in other cases may not be well-known to CDM market participants.

We have focused on evaluating a select group of different types of offset projects to highlight different challenges that could not have been anticipated before these kinds of projects actually were developed. Before they experienced the implementation challenges described in the case studies, many market participants had expected these types of offset projects would be relatively simple to develop and implement and would create large amounts of offset credits. The implementation problems described in these case studies reduced the amount of CERs delivered in the market to levels far below what project developers had expected to create, and for which buyers had contracted to buy. It is important to note that the problems experienced by project developers highlighted in this paper took place within the specific context of the CDM, and not a U.S.-based offsets program. Based on each case study, the authors have tried to evaluate whether and to what extent similar problems may be expected to arise within the context of a future U.S. federal or regional GHG offsets program. These case studies also provide relatively detailed information related to CDM rules, procedures and decisions.

Each case study describes unanticipated problems associated with the implementation each of the types of offset projects evaluated. These case studies are not meant to describe in a comprehensive way all of the issues related to these project types, but to point out critical – and, in some cases lesser-known – issues associated with the implementation of these project types. The analysis presented here is based on the authors' experience working for a company that contracted for many CDM projects, working with developers attempting to secure all necessary approvals, and analyzing delivery risks for its investors.

Some of the issues described in the case studies may not be directly applicable to a future U.S. federal or regional GHG offsets program. On a broader level, however, many of the issues described are likely to be highly relevant. As suggested by these case studies, "learning by doing" is likely to be unavoidable as part of the implementation of any future U.S. offset system. Although the designers of a U.S. offset program will have far more experience upon which to draw during its development than did the designers of CDM, unexpected issues nonetheless are likely to arise in the implementation of any future U.S. program. The case studies illustrate some of the challenges that may emerge.

2. Landfill Gas Projects

Landfill gas (LFG) projects designed to flare methane (CH_4) or utilize it for energy production constituted a large share of CDM projects registered[14] before mid-2007. This was consistent with the generally-held expectation that these kinds of offset projects would be straightforward to implement and would yield good financial returns. However, once LFG projects were implemented and performance monitoring began, the actual amounts of GHG emission reductions achieved turned out to be far less than originally estimated. This case study examines some of the reasons for these lower-than-projected emission reductions, and to what extent these factors have been addressed in the current methodologies used to estimate emission reductions for LFG projects.

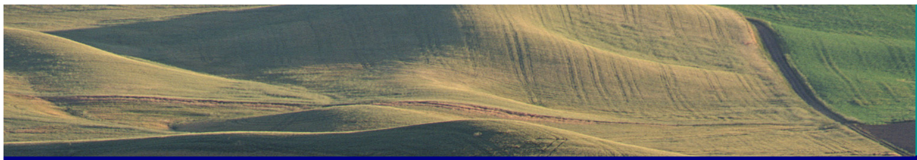
In the early days of the CDM, project developers viewed LFG projects as "low-hanging fruit," and a promising offset project type.[15] The technologies used to destroy methane contained in LFG by flaring or utilizing it to generate heat or electricity were considered mature, and project developers were able to transfer the technology and implement LFG projects in developing countries eligible to host CDM projects. Demonstrating additionality for these projects is straightforward, making project approval more likely than for other offset project types. Few developing countries have existing laws or regulations that require LFG destruction, so it is easy to demonstrate regulatory additionality.[16] In addition, LFG projects easily can pass the CDM's financial additionality test because the cost to implement LFG projects is a significant disincentive to developing LFG projects.[17]

For these reasons, offset project developers quickly began to implement LFG offset projects, and LFG projects accounted for a high proportion of the projects registered early in the CDM program. A landfill gas-to-energy project in Brazil was the first offset project to secure formal CDM registration in 2004. In 2005, LFG projects represented 16% of projects registered in the CDM. Since then, registration for LFG projects has slowed considerably.

The actual issuance[18] of offset credits as a percentage of estimated emission reductions has varied among LFG projects. As of December 1, 2010, the average issuance rate for LFG projects was only 40% of the "design estimates" contained in the relevant Project Design Documents (PDD),[19] varying widely from 5% to 90%.[20] Although at least four projects registered before mid-2007 have requested issuance of CERs for 80% or more of the design estimates,[21] the majority of projects registered early in the CDM have performed poorly when compared to their estimated emission reductions. Some project proponents simply stopped requesting issuance of offset credits shortly after the start of their LFG projects due to poor performance.

For example, the Canabrava LFG project[22] in Brazil was estimated to create an average of 200,000 tonnes CO_2e of emission reductions per year, but in its first monitoring period the project produced only 5% of this estimate. Other projects have not yet requested issuance of any offset credits for associated emission reductions. The Olavarría LFG recovery project[23] was registered in 2006, but has not requested issuance. It is one of 18 early registered LFG projects which have yet to do so. According to one study, this project has experienced poor performance, and yielded fewer emissions reductions than the 18,688 tCO_2e it was estimated to generate annually,[24] which may explain why the project developer has not yet submitted a request for offset credits to be issued for this project.

Such variable and mainly poor results can be attributed primarily to two factors: (i) the tendency of project developers to over-estimate expected emission reductions based on the guidance contained in the CDM LFG methodologies; and, (ii) landfill management conditions that tend to reduce potential LFG emission reductions. Because LFG technology is well-developed world-wide, underperformance of LFG projects due to faulty equipment is not likely to have been a significant cause of the lower-than-expected emission reductions.



2.1 Methodologies

In the CDM, a baseline and monitoring methodology must be approved by the CDM Methodology Panel (Meth Panel) and Executive Board (EB) before an offset project using that methodology may be registered. Throughout the history of the CDM, the Meth Panel and EB frequently have revised existing offset methodologies. These ongoing revisions exemplify the CDM's "learning-by-doing" approach. Before the EB approved the registration of any offset projects, the EB approved five methodologies that could be used by project developers to prepare project documentation and emission reduction estimates for LFG projects. The first four methodologies later were consolidated into one methodology and are no longer available for use. The methodology currently in use is in its eleventh version, and is the only methodology approved to be used for large-scale CDM project activities that destroy or utilize LFG. As discussed below, these revisions have aimed to improve the methodology and lead to more conservative emission reduction estimates.

In CDM LFG projects, emission reductions are made by destroying and/or utilizing methane contained in landfill gas. Generally, potential GHG emission reductions are estimated by using first-order decay equations, which attempt to model the expected loss of carbon content in waste over time. Most models estimate potential LFG generation based on the quantity of waste contained in a landfill, the time when wastes were disposed, and the application of parameters to account for carbon loss over time. However, the methodologies used for projects registered prior to mid-2007 provided project developers with little guidance to prepare *ex-ante* estimates of landfill methane generation. As a result, project developers used different models to estimate potential emissions reductions, leading to inconsistencies in the way emissions reductions were calculated. One of the methodologies simply required application of a first-order decay model. Another methodology attempted to be more precise, specifying the use of a model developed by EPA. None of the methodologies provided project developers with explicit guidance regarding calculation methods and adjustments based on specific site conditions. In December 2007 this guidance became available in the methodologies, with the addition of a requirement to use the "Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site."

Because only open-ended guidance was provided in the LFG methodologies, project developers applied different models to estimate expected LFG production, and in some cases these models were not appropriate to be used to estimate methane generation in developing countries. Some used the Rettenberger model – a simple model that estimates LFG production based on the total organic content of waste, a degradation factor, and the number of years of landfill operation. Others used models developed by the Intergovernmental Panel on Climate Change (IPCC) and EPA. Both of these approaches directly estimate $CH_{4,}$ and include a CH_4 generation potential in their calculation; the latter factor is based on the amount of decomposable degradable organic carbon contained in the waste. Despite the similarity of the IPCC and EPA models, the IPPC model was developed for flexible application to country-specific conditions, while the EPA model includes default parameters based on the conditions common in many U.S. landfills.

2.2 Project location and management conditions

Models used to project landfill gas production, particularly those which use default values for the decay constant and CH_4 generation potential, often estimate the CH_4 generation potential based on optimal conditions.[25] Actual CH_4 generation at a landfill is affected by several factors, including climate, waste characteristics, and landfill management practices. When these factors are not represented in a model used to estimate CH_4 generation potential, poor estimates of emission reductions from LFG projects are likely to result. Moreover, models like the *EPA Landfill Gas Emissions Model* (LandGEM) reflect climatic, waste and management conditions which should not be applied to developing countries without some adjustments. The lack of guidance in the CDM methodologies for how to apply such models to developing country conditions likely contributed significantly to the over-estimation of potential emission reductions in CDM LFG projects.

Landfills are complex systems, and management practices significantly affect the potential generation of CH_4 and the ease with which it can be extracted. Some landfills where CDM projects were implemented may not have been designed and built with LFG extraction in mind, and may not generate CH_4 at the rate the models suggest given the quantity of waste in place. Below are some landfill conditions which affect potential CH_4 generation.

- CH_4 is generated under anaerobic conditions (i.e., in the absence of oxygen). Landfills in which anaerobic conditions cannot be maintained will release CO_2 more readily than CH_4. Such conditions may occur where waste has been poorly packed, or the landfill cover is permeable to the air.

- CH_4 generation requires moisture. A landfill which is too dry is unlikely to be anaerobic. In these cases, pockets of anaerobic activity may be created from the natural moisture in the waste, and CH_4 will be generated only in these pockets rather than throughout the landfill. Conversely, a landfill that is too wet may also be unable to generate CH_4, and the excess moisture may block gas wells which release LFG to the atmosphere. Instead, LFG may dissolve in the leachate. Inadequate moisture conditions may arise due to use of a low-quality liner, a permeable landfill cover, or poor leachate management. A low-quality liner may be permeable and release landfill leachate into the surrounding soil or water table, which also has environmental implications beyond the impact on CH_4 generation. A permeable cover may result in loss of moisture to the atmosphere or the addition of rainwater to the landfill. Poor leachate management, such as the absence of leachate drainage, could result in unequal moisture conditions throughout a landfill or very high moisture levels which inhibit CH_4 generation. In some cases, a system that drains leachate from the landfill and re-circulates a portion of the drained liquid may create optimal and relatively homogeneous moisture conditions for CH_4 generation.

- Some types of waste decompose more easily than other types, and produce CH_4 at faster rates. Food waste is high in readily decomposable, degradable organic carbon. Under anaerobic conditions, it will decompose quickly into CH_4, but the CH_4 generation period is short-lived. Less easily decomposable wastes, such as textiles or yard waste will generate CH_4 over a longer period of time, but at a lower rate. The modeling of waste decomposition rates is discussed further below.

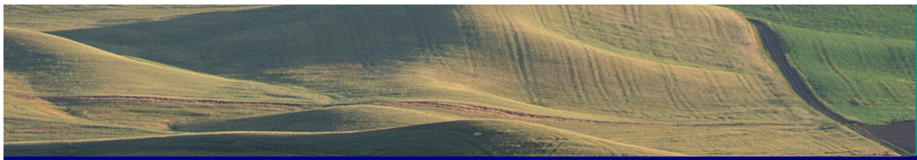
- CH_4 generation occurs more readily and more quickly at warmer temperatures. All other factors being equal, more CH_4 will be produced in a warmer climate, and it will be produced at a faster rate. The majority of a landfill's emissions occur during the earlier stages of the decomposition of available organic content. Once a landfill is closed and no more degradable organic carbon is added to it, the amount of CH_4 generated by the decomposition process declines with each passing year. In landfills in which emissions rates are high (e.g., in warmer climates), a large portion of the landfill's total expected emissions may have occurred before the start of an LFG project. This limits the number of years that a project can generate enough emission reductions to be economically viable.

- The CH_4 generation constant, or decay rate (k), which represents the ease of waste degradability, is affected by temperature. A decay rate applied in a model designed for use in a cooler climate will poorly represent CH_4 generation that may occur in a warmer climate under the same conditions. Although the EPA's recommended default factor (k=0.04) may be representative of the average decomposition rate of waste in a typical U.S. landfill, different decay rates are likely to be appropriate to be used for landfills located in a tropical climate and for easily decomposable wastes.

- For example, the Canabrava landfill, which no longer was receiving waste at the time the CDM LFG project began to be implemented, used a decay rate of k=0.05 in the project developer's calculations. This factor may not have depicted accurately the rate of waste decomposition, due to the decomposability of waste in the warmer Brazilian climate. This may be one reason why emission reductions were overestimated for this project. It is possible that much of the CH_4 expected to be generated already had been produced before this offset project began operations, and the remaining amount of degradable organic carbon available to create additional CH_4 was low. A higher decay rate may have resulted in a better representation of the conditions of the landfill and the relatively rapid waste decomposition.

2.3 How these issues have been addressed

At the 35th meeting of the CDM EB in October 2007, the first LFG methodology was revised to become version 7 of the methodology (the current version in use), and all other LFG methodologies were withdrawn. The revised version of the methodology introduced a new calculation tool to estimate CH_4 emissions from a landfill.[26] This tool includes an equation to estimate CH_4 emissions from a solid waste disposal site, and is mandatory for all projects to be developed using ACM0001. It draws heavily from the IPCC model, and aims to encourage more accurate and conservative estimates of potential emissions reductions. Its use should result in more uniformity in the selection of input parameters used to develop CH_4 estimates. Project developers are given default waste decay rates for four types of waste of varying degradability, depending on the climatic conditions (i.e., temperature and precipitation) where the landfill is located. This model also corrects for the level of management and the depth of the landfill, which affect anaerobic conditions.



Missing from this calculation tool is the actual moisture content inside the landfill and the permeability of the cover. Actual moisture content is affected by other factors beyond the amount of precipitation. If the landfill cover is not impermeable, it can allow CH_4 to be released or oxygen to enter the landfill. To address these and other uncertainties, and to increase conservativeness, the tool applies a model correction factor that reduces estimated CH_4 generation by 10%. Whether this is an appropriate correction factor depends largely on the specific conditions at the landfill.

As of January 1, 2011, several projects have been registered using this new calculation tool, but only one of these projects (a Chilean LFG project) has been issued CERs.[27] Based on two monitoring reports[28] spanning 18 months, this project has achieved about 91% of its estimated emission reductions. Though this is a promising indication of more accurate estimates, additional issuance of credits to this and other projects will confirm if the new calculation tool has led to more conservative and realistic emission reduction estimates.

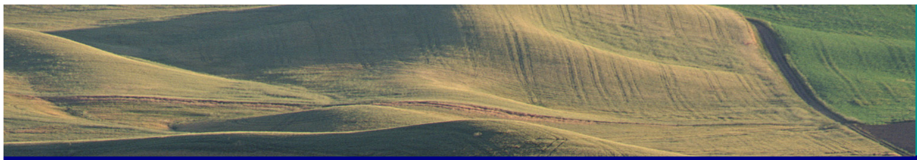
Early LFG methodologies in the CDM lacked comprehensive instructions related to estimating the potential for CH_4 generation in a landfill. Consequently, models not appropriate for LFG projects implemented in developing countries were applied to these projects in many instances (see Box 2).

Though variability between landfills conditions within a developed country like the U.S. may not be as large as the variability on landfills conditions between a developing and a developed country, project-specific differences should be expected, and it would be prudent to account for these when drafting methodologies for LFG projects in any new offset system. Local climate, waste characteristics, and landfill management practices are key variables that may lead to differences between regions. In the future, it may be more effective for LFG project methodologies to provide a uniform approach to be used to estimate CH_4 generation potential combined with flexibility to use different input values or other approaches to reflect site-specific conditions. This flexibility could help to avoid large overestimation of emission reductions, frequent methodology revisions, and unnecessary risk and uncertainty for project developers and buyers of offsets.

Box 2: An example of the poor application of model parameters to estimate emission reductions from an LFG project in a developing country

In the absence of guidance for determining appropriate input parameters, the application of any specific model to estimate methane production from an LFG offset project can yield varying and inaccurate results. There are two parameters used in many LFG models, including the EPA and IPCC models, which largely determine the estimated quantity of CH_4 expected to be generated from a given landfill. First, the CH_4 generation constant, k, accounts for the ease of waste decomposition, which is mainly affected by climate and type of waste. Second, the CH_4 generation potential, Lo, reflects the quantity of degradable organic carbon available in the waste for decomposition. For GHG emissions inventory purposes in the U.S., the EPA model recommends default values of k=0.04 and Lo=100; higher values of either parameter increase estimated CH_4 generation. Early versions of CDM methodologies for LFG projects, even those methodologies which stipulated the use of the EPA model, did not require the use of these specific default values, nor did they provide guidance regarding the selection of conservative parameters.

For example, the Canabrava LFG project applied the EPA LandGEM model and used input values of k=0.05 and Lo=180. The project landfill had stopped receiving waste and had been closed by the time the project began. Though a landfill continues to emit CH_4 after it is closed, the quantity of carbon available for CH_4 generation decreases over time since there is no new waste input. In this case, the higher input value applied for CH_4 generation potential, Lo, led to significant overestimation of the actual measured emission reductions achieved by this project. Moreover, the low value applied to the CH_4 generation constant, k, may not accurately have reflected the climatic conditions and waste characteristics at the landfill. These conditions may have led to a quicker decomposition of waste, where only small quantities of easily decomposable degradable organic carbon were available for CH_4 generation by the start of this CDM project. As a result of these issues, the amount of CERs actually issued for the nine months the Canabrava LFG project operated as a CDM project were only 5% of the emissions reductions estimated in the PDD.



2.4 Applicability to a U.S. offsets program

As described above, LFG projects in the CDM often have created fewer emission reductions than expected for two reasons: (i) the first LFG methodologies approved by the Meth Panel did not provide any guidance for how to estimate LFG potential, so project developers applied landfill gas models that did not take into account site-specific conditions or correct for site-specific waste composition, resulting in overestimates of LFG generation potential and emission reductions; and, (ii) the LFG models used to estimate CH_4 generation potential did not sufficiently account for landfill conditions and management practices that affect the anaerobic conditions in landfills and resulting LFG generation.

The same two factors could apply in the context of a future U.S. offsets program. The Climate Action Reserve's (CAR)[29] U.S. Landfill Protocol calculates actual CH_4 emission reductions based on measured amounts of LFG captured and destroyed. However, it does not provide guidance for how to estimate LFG potential. Instead, it notes that there are different landfill gas models available, but does not specify which one should be used to estimate baseline emissions. As in the CDM, project developers may choose models such as the EPA's LandGEM model which assumes waste is homogeneous (i.e., it does not account for different types of waste with different rates of decomposition), and does not take into account site-specific landfill management practices. As a result, LFG estimates may not be representative of the actual LFG generation potential of a proposed project. Moreover, since project developers can choose which LFG model to use, a range of estimates of LFG production potential can be expected even in cases where landfills have similar characteristics such as climate, depth, and waste composition.

In addition to these methodological issues, LFG projects in the U.S. simply may not be eligible to create offsets under existing and evolving offset programs. For example, despite the significant quantity of offset credits that have been issued and will continue to be created using CAR's existing U.S. Landfill Protocol, the California ARB determined that LFG would not be allowed as an eligible offset category because the state already regulates CH_4 emissions from landfills. Under the Western Climate Initiative (WCI), offsets only can be generated and recognized for activities that are *not* required by any existing regulations in place in any of the WCI member states. This implies that LFG-based offset projects will not be permitted in the WCI because of California's existing landfill management regulations.

A federal offset program may decide not to allow the use of offset credits from LFG projects in states which do not regulate LFG emissions, based on the argument that allowing the use of these offset credits would: (i) discourage non-regulating states from regulating LFG emissions because it provides benefits to local project developers; and, (ii) punish those states that already regulate LFG emissions.

3. Agricultural Methane Digester Projects

An agricultural CH_4 digester offset project is one in which an anaerobic manure treatment system[30] is replaced with an improved animal waste management system (AWMS) which reduces GHG emissions. A common example of this type of project is the replacement of an uncovered liquid manure storage tank with an anaerobic digester, such as an anaerobic lagoon equipped with a CH_4 collection system. Digesters come in various forms and systems, including covered lagoons, mixing, plug flow, and fixed film, and also can be used for food wastes and other types of biomass.[31]

In the context of an offset project, anaerobic digestion allows for the capture of "biogas" from manure storage, where CH_4 is a key component of this gas.[32] Instead of being released to the atmosphere, the biogas is flared or used to generate electricity, heating, cooking or lighting. In the CDM, project developers are able to claim offset credits for emission reductions associated with the avoided release of CH_4 and displaced fuel or electricity use if applicable.[33]

The challenges associated with implementing agricultural CH_4 digester projects became well known in April 2008 when the prominent agricultural CH_4 project developer AgCert de-listed its shares from London's Alternative Investment Market, and went into "examinership" to develop a restructuring plan to repay its debts.[34] According to news coverage, the company "pre-sold more [CERs] than it was able to generate in 2008, meaning it would have to replace those it could not create by buying credits in the open market at a price it could not afford."[35] Subsequently, AgCert was taken over by AES Corporation, a power company that was an AgCert creditor.[36] Currently, AgCert is still a leading developer of agricultural CH_4 projects. Regardless, carbon market observers and participants often associate AgCert's experience with the risks related to creating offsets in the CDM. According to one article, the company pre-sold more credits than it could deliver because "the technology did not live up to expectations and the UN changed the methodologies of calculating carbon credits." Elsewhere it was suggested that delivery delays were responsible for the company's problems.[37]

Based on a review of agricultural CH_4 digester projects, it is apparent that the success of these projects in the CDM has been less than expected. Out of 342 projects in the CDM Pipeline as of January 1, 2011,[38] only 53 had been issued CERs, realizing an average of 48% of estimated emission reductions. The majority of the projects are located in Mexico.[39] For these Mexican projects, the average rate of CER generation was just 30% of the emissions reductions estimated in the PDDs, excluding two outlier projects which had issuance rates of 107% and 157% due to higher animal populations than assumed in the PDDs.

This case study of agriculture CH_4 digester projects explores technological difficulties that contributed to these relatively low CER issuance rates, methodological developments that have raised questions regarding the economic feasibility of these projects, and another factor which may have contributed to the under-performance of these projects that is discussed below.

3.1 Technological difficulties

As with LFG projects, there are several factors, such as climate and manure characteristics, that affect the quantity of CH_4 captured by an anaerobic digester. Though these factors likely have contributed to the variable performance of CDM anaerobic digestion offset projects, the underperformance of projects, particularly in Mexico, may be due to other operational reasons.

Implementing AWMS at livestock farms in Mexico involved the introduction of new technology to small farms. Because the technology was new to the region, technical know-how was not readily available, resulting in operational and maintenance complications. For example, providing technical support for maintenance required using experts from other cities or countries.[40]

In addition, similar to LFG projects, temperature plays a key role in the amount of CH_4 that is generated by an anaerobic digester. However, unlike landfills, the temperature in an anaerobic digester is controlled as part of the digester's operation. A temperature of 25-30 ºC is required for optimum operation, but some farms located in cooler regions may be unable to maintain such temperatures.[41] It is possible that some of the underperformance of the Mexican projects was partly due to less than favorable temperatures. For example, the CDM project "AWMS GHG Mitigation Project MX06-B-32, Aguascalientes and Guanajuato, México"[42] generated approximately 40% of the emission reductions estimated in the PDD. This low percentage partly could be attributed to cooler operational temperatures, which according to the project monitoring reports were below 20°C on average.

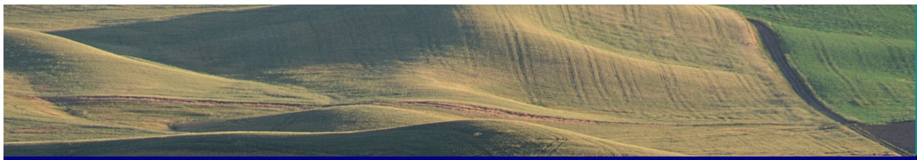
Other operational measures that might unintentionally reduce the CH_4 generation potential of these projects include the use of antibiotics and non-biodegradable products used to clean animal stalls, which may affect CH_4-generating bacteria.[43] However, the overall impact of these factors on methane generation is not documented in any of the available monitoring data.

3.2 Methodological concerns

In 2004 the EB approved two methodologies that apply to agricultural methane digester projects.[44,45] In September 2006, these methodologies were consolidated into "Consolidated baseline methodology for GHG emission reductions from manure management systems."[46] Digester projects that had not submitted a request for registration before this date were required to use the consolidated methodology, while projects that had been registered or submitted a request for registration before this date were allowed to continue to use the original methodologies.

The consolidation of the methodologies raised concerns from project developers that certain new provisions in the consolidated methodology would undermine the economic feasibility of future projects. These included provisions requiring direct monitoring of the flare used to destroy the CH_4, provisions introducing the use of a standard CH_4 conversion factor (MCF) established by the IPCC, and a requirement to account for physical leakage from the anaerobic digesters (which typically equals approximately 15% of total biogas production). The consolidated methodology assigned a default flaring efficiency of 50% where the CH_4 is destroyed in an open flare, and a default flaring efficiency of 90% where the CH_4 is destroyed in an enclosed flare[48] and the efficiency is not monitored.[49] Relative to the original methodologies, the new provisions had the potential to significantly limit the amount of offset credits that would be claimed for projects using open flares. Moreover, the additional monitoring requirements were expected to lead to higher operational costs.

However, based on a review of registered Mexican digester projects, most projects used closed flares and already used an MCF consistent with the IPCC factor. In addition, as noted above, the consolidated methodology did not apply to projects that already



had been registered under the original CDM methodologies. This suggests that many of the methodological concerns raised by project developers may have been secondary to other problems with digester projects, such as temperature and other site-specific conditions.

3.3 Other potential factors

As suggested in the discussion above, the poor performance of agricultural CH_4 digester projects does not seem to be related to methodological problems. It seems more likely that underperformance was due to other operational difficulties encountered after implementation of the projects, such as the temperature issues discussed above, or lack of performance data, as discussed below.

Many of the agricultural CH_4 digester projects in the CDM are comprised of multiple farms. As a result, the monitoring of project-related emission reductions is the responsibility of multiple participants. Based on a sample of monitoring reports, monitored data from some sites was found to be missing. It is possible that difficulties associated with ensuring proper implementation of the project monitoring plan resulted in less than expected emission reductions compared to PDD estimates. Moreover, this might have deterred project developers from pursuing these projects.[50] Therefore, it appears that some of the underperformance seen in the project monitoring reports may be a reflection of poor monitoring practices that resulted in missing data.

The information presented above suggests that significant underperformance of particular project types may be caused by a number of factors unique to those project types. These may include a combination of methodological issues and operational challenges. This illustrates the potential complexities involved in accurately predicting the amount of offsets projects will generate.

3.4 Applicability to a U.S. offsets program

In the CDM, the factors which contributed to anaerobic digester projects (mainly in Mexico) yielding fewer CERs than estimated in the respective PDDs included: (i) a lack of familiarity with the technology, and a lack of experts in the region to maintain anaerobic digesters; and,(ii) site-specific conditions such as lower-than-expected temperatures, the use of antibiotics, and challenges associated with compiling complete monitoring data in projects involving multiple farms.

Although anaerobic digestion is not common in the U.S., there is a fair amount of experience in the U.S. implementing these projects. As such, the lack of technical expertise that hindered the success of the Mexican CDM projects is unlikely to affect U.S. digester projects. According to the U.S. EPA there are only about "150 operational anaerobic digestion systems in the U.S." The U.S. Department of Agriculture's (USDA) AgSTAR program estimates there are 171 systems, as discussed below, but there is potential to introduce advanced waste management systems in dairy and swine operations in over 8,000 farms.[51,52] This AgSTAR program is operated through a partnership of three federal government agencies, and was established to promote the use of anaerobic digesters in livestock and poultry operations.[53] It provides project developers with the information resources to promote the use of anaerobic digestion systems, including information on a roster of experts that can assist with developing and operating projects.[54,55] Rather than using project developers like AgCert, which developed and implemented many Mexican digester projects and often aggregated multiple participants in a single project, individual U.S. famers are more likely to implement anaerobic digester projects on their own, using support provided by programs like AgSTAR. This would minimize the risk of losing monitored data as experienced in some CDM projects. According to the AgSTAR website, many of the 171 anaerobic digester systems operating in the U.S. have been funded in part by USDA Rural Development.[56]

In addition to the methodological factors that affected the amount of CERs created by CDM digester projects, other factors such as the offset protocol used by project developers will affect the level of offset crediting. Based on an offset protocol "roadtesting" study undertaken for EPA, estimates of project-related emissions varied significantly for a sample project due in large part to differences in estimated project emissions from the biogas system.[57] These and other differences in baseline and emission reduction calculations contributed to expected offset quantities ranging from zero to as high as 466 tons depending on which protocol was used.[58] Under the CAR protocol, the project (project #1) would not have been undertaken.

In addition to such factors, digester projects also may face significant challenges in the U.S. due to questions regarding their economic feasibility. EPA concluded in a market study that digester projects were economically feasible, but the study does not take into account emissions leakage – i.e., emissions caused by the project outside of the project boundary, which needs to be taken into account in calculating a project's estimated emission reductions. Typically, emissions leakage can equal about 15% of the total biogas production.[59]

4. Waste Heat Recovery Projects

Waste heat/gas recovery (WHR) is the use of fugitive heat or gas emissions from industrial processes to produce heat and/or electricity, or to dry raw materials. Various industries (e.g., cement production, coking, iron and steel plants, paper mills) can implement WHR systems in their production lines to generate electricity and/or heat. The output generated can be used by the host facility or sold on the regional electricity "grid" or directly to other end users. WHR projects constitute roughly 9% of the CDM project pipeline, with 90% of these projects located in China and India.[60] This case study examines key difficulties faced by WHR projects in the CDM registration process.

WHR project activities have faced scrutiny from the EB, and in the past the EB has requested review[61] of many of these projects related to concerns about the ability of these projects to demonstrate additionality or the proper use of the WHR methodology. Between 2007 and 2010, the EB requested reviews of more than 140 of the 619 WHR projects that requested registration. Subsequently, 20% of these projects were rejected.[62] As discussed below, the most common reasons the EB requested reviews of WHR projects had to do with the ability of proposed projects to demonstrate additionality based on CDM's additionality tests, including the barrier test, the investment test and the common practice test. These CDM additionality tests are described in more detail in Box 3.[63]

Other rationales given by the EB for their requests for review were used less frequently, and included evidence of CDM consideration (discussed below), baseline determination, and validation of the *ex-ante* grid emissions factor used to estimate emission reductions.

Box 3: Additionality Tests in the CDM

A project is considered to be additional under the CDM if it (i) meets the requirements of two tests – *either* the investment test *or* the barrier test, *and* the common practice test – and, (ii) if the PDD demonstrates that CDM was seriously considered as part of the undertaking of the project activity. These three tests are described below.

Investment Test: In an investment test, the project developer must demonstrate that if revenue created by the project's offset credits were not available, the project would not be financially feasible, or its rate of return would not be attractive. This approach assumes CERs created by the project are a decisive reason for undertaking a proposed project. It assumes the project would not be viable or attractive in the absence of the revenue created by the sale of offsets.

Barrier Test: A barrier test considers whether there are significant barriers to implementing an offset project – such as local resistance to new technologies – in the absence of revenue from GHG reductions. If such barriers exist and only can be alleviated by crediting offsets under the CDM, the project is assumed to be additional. The barrier test applied by the CDM requires that at least one realistic alternative to the project must not confront these barriers for the project to be additional. This approach assumes crediting of GHG reductions are the decisive factor that makes it possible for the project to overcome existing barriers.

Common Practice Test: This test typically compares the emissions performance of the project to "common practice" technologies or activities in the relevant sector and region. If a project developer does not show the offset activity to be undertaken is not widespread in the sector (i.e., BAU) and/or the project can achieve greater emission reductions than other technologies/activities, it is assumed that emission reductions were not a decisive reason for undertaking the project. Consequently, the project is not considered to be additional. The CDM's application of this test differs somewhat. It identifies other technologies/activities operating in the region that are similar to the proposed project activity, and considers whether those activities faced barriers or enjoyed benefits that are not applicable to the project to make an additionality determination.

Some of the requests for review reflected the lack of guidelines and policies for demonstrating additionality at the time these requests were issued. The reasoning behind the requests for review and the outcomes of the reviews were summarized in information notes on EB decisions, and in general guidelines on the assessment of the investment test and barrier test. Such information established an important precedent for subsequent projects, and has benefited project developers and Designated Operational Entities (DOEs) – i.e., independent, third-party auditing, accounting, engineering or similar organizations accredited by the CDM EB to validate[64] projects and verify[65] GHG emissions reductions associated with offsets projects. In particular, the barrier test now is seldom used, and the DOEs are trying to better address – before the request for registration – issues that tend to trigger requests for review related to the application of the investment and common practice tests. Although requests for review for WHR projects continue to be issued by the EB, they are less frequent. Only 21 requests for review were issued in 2010 compared to 65 in 2008.

4.1 Investment test

WHR project developers have the option to demonstrate additionality using the investment test *or* the barrier test, *plus* the common practice test. The investment test often is preferred to the barrier test, as more guidance is available and the supporting evidence is more accessible. As a result, most WHR projects use the investment test. However, the investment test presents other challenges for WHR projects, and more than 80% of the EB requests for review for these projects related to the investment test.

According to the CDM's "Tool for Demonstration and Assessment of Additionality," a project developer may choose to demonstrate additionality using the investment test through a simple cost analysis, a cost comparison analysis or a benchmark analysis.[66] The latter is most commonly used. The requests for review issued by the EB mainly questioned the DOE's validation of the input values[67] used to calculate projects' internal rate of return (IRR) or net present value (NPV), or the DOE's validation of the suitability of the IRR benchmark. In approximately 20% of the cases, the EB rejected the proposed projects. These rejections largely were due to concerns about the suitability of the IRR benchmark. The IRR benchmark is the industry's "target" rate of return to be achieved in the absence of revenues from CER sales. The estimated IRR for a proposed WHR project in the absence of CER revenue must be shown to be lower than the IRR benchmark for the project to be considered financially additional.

In the case of WHR projects that generate electricity, the EB questioned whether the "applied benchmarks appropriately reflected the risk profile of the investment being made."[68] Specifically, the EB questioned whether the benchmark for the core business of the facility on which the project was implemented (e.g., cement industry, coking industry) was suitable for the investment test.

In assessing WHR projects that generated electricity, the EB considered whether the electricity would be generated for use by the industrial facility, or predominantly sold to the grid or other end users. In cases where electricity generated was to be used by the host industrial facility (i.e., 75% of the power output or more would be consumed by the industrial facility), the core business's industry benchmark was deemed appropriate. In other cases, the "project was considered to be an investment in power production and therefore to face a risk profile different to that of the core business of the project developer."[69] That is, the EB ruled the proposed project should have used an IRR benchmark for the electricity sector. This was a critical decision because the IRR benchmark for the electricity sector is lower than for the industries in which WHR projects are implemented. This made it more difficult to prove the financial additionality of WHR projects that generated electricity mainly for sale to the grid. In cases where a proposed WHR project would not reduce the consumption of any other fuel at the industrial facility and would generate income through electricity sales, the EB argued the project would be more financially attractive than those WHR projects producing electricity for use by the industrial facility. Consequently, the EB required project developers to provide evidence that the benchmark used was the most stringent available (e.g., the electricity sector's IRR, where appropriate), or that the project was not financially attractive regardless of the benchmark used.

Coke oven gas (COG) WHR projects implemented in coking plants in China were particularly impacted by the EB's decision. Many of these projects were selling more than 75% of the generated electricity to the regional electricity grids, and so were required to demonstrate additionality using the government-issued electricity sector benchmark of 10% instead of the coking industry benchmark of 12 %. The IRR of the majority of the projects called for review exceeded the 10% benchmark and were rejected. Although the rejection of these projects does not rule out the eligibility of this category of projects in China, it does create obstacles for future projects related to the "common practice test" as discussed below

The EB also has questioned the cost assumptions used to calculate these projects' IRRs and NPVs. More recently, the EB has questioned the assumed operation and maintenance (O&M) costs in the feasibility study reports. The EB has expressed the view that the O&M costs are higher than what has been observed in the region, suggesting that the costs have been inflated to increase the IRR. The renewed scrutiny could be a reflection of the EB's concern regarding the financial additionality of this type of project in light of its short payback period.

4.2 Barrier test

Another common reason for requests for review relates to the use of the barrier test. To demonstrate additionality using this test, a project developer is required to show that barriers particular to the project prevented its implementation, and that these barriers could be alleviated by the CDM. However, project developers have had difficulty identifying and substantiating credible barriers to the project activity. This has been the case particularly for WHR projects implemented in the cement industry, for which project developers have identified the following barriers: (i) "*Investment barrier*" – they have no access to capital, or bank loans; (ii) "*Technological barrier*" – they are adopting sophisticated technology that is more expensive than available alternatives and is subject to a greater number of operational difficulties; and, (iii) "*Prevailing practice barrier*" – the establishment of a WHR facility requires particular skills and expertise not available in the area.

Project developers have faced difficulties carrying out the barrier test due to poor supporting evidence. In the case of rejected projects, developers failed to show evidence specific to their project. For example, projects UNFCCC Ref No. 2780[70] and Ref. No. 2851[71] were rejected partly because the evidence provided was "generic in nature and not specific to the project activity."[72]

To assist DOEs and project developers with demonstrating barriers to the implementation of a project activity, the EB issued "Guidelines for Objective Demonstration and Assessment of Barriers."[73] However, because of the difficulty of providing substantial, project-specific evidence, project developers often have opted to use the investment test as the first step to demonstrate project additionality. As a result, fewer WHR projects are using the barrier test, and the number of EB requests for review of WHR projects using the barrier test is decreasing.

4.3 Common practice test

The common practice test is an assessment of a proposed project against other similar project activities occurring in the region. It acts as a check on the investment or barrier tests, where project developers must show the project activity is not BAU for the industry. Although the EB has requested review of WHR projects in connection with their use of the common practice test, it is not a leading reason cited for rejection.

Nonetheless, as discussed above with regard to the use of the investment test, the EB's concern regarding the risk profile of WHR projects generating electricity for sale has had an impact on the ability of project developers of COG projects to demonstrate the activity is not BAU. As discussed above, the EB's requirement to assess the financial attractiveness of this type of WHR project against an energy sector benchmark led to the rejection of more than 50% of the COG projects in the pipeline. Consequently, for the purpose of the common practice analysis, these projects now are deemed as BAU by DOEs. The extent of the impact of this decision is not yet clear, but it has become increasingly difficult for developers of COG projects to pass this step of the additionality test.

The EB's concern regarding the suitability of the benchmark for project activities selling 75% or more of the generated electricity was not anticipated by project developers, because WHR methodologies and the CDM's "additionality tool" did not provide sufficiently specific guidance on which IRR benchmark to use based on the specific type of WHR project being implemented. Because of this lack of guidance, which may have been due to the EB's insufficient understanding of, or experience in reviewing different WHR projects, many WHR projects that expected to be approved were rejected.

4.4 Applicability to a U.S. offset program

In the CDM, WHR projects face scrutiny from the EB with respect to demonstrating financial additionality. There are strong reasons to believe that WHR projects implemented prior to 2008 in the U.S. would not have difficulty proving their financial additionality, if such a test were imposed. An EPA 2008 report on "Environmental revenue streams for combined heat and power"[74] indicates that financial hurdles have prevented WHR technology to be widely adopted by manufacturing industries. Another EPA report[75] on energy opportunities for some manufacturing sectors also suggests that WHR for electricity generation has not been fully adopted because there are other low-cost energy alternatives available.

However, more recent U.S. government actions to spur increased up-take of WHR technologies may call into question the potential additionality of these projects. Two recent federal laws[76] provide support for WHR technology (categorized as Combined Heat and Power (CHP) technology). These are: (i) the Energy Improvement and Extension Act of 2008 (EIEA); and, (ii) the American Recovery and Reinvestment Act of 2009 (ARRA). These laws provide tax credits, grants, and loan guarantees to facilitate the adoption of CHP systems. If similar provisions benefitting CHP are in place when a U.S. offset program is being created, policymakers will need to assess if CHP projects actually are additional – i.e., whether these projects would have taken place in the absence of the offset program due to government support. If the projects are considered to be additional, their baseline emissions estimates may need to be adjusted to reflect technologies adopted as a result of federal support. If a CHP offset methodology is developed in this context, it would need to take these factors into account, as well as how the removal of federal or other governmental support for CHP projects would impact the additionality of proposed projects. A similar issue – the removal of Chinese government subsidies for wind power projects – led many CDM wind projects to be determined to be non-additional and no longer eligible to create offsets. This issue is discussed in section six.

5. Afforestation / Reforestation (A/R) Projects

Growing trees can remove carbon from the atmosphere and sequester it in growing biomass for long periods of time. Under the KP, the CDM is limited to considering only "afforestation" and "reforestation" activities as potential types of forest carbon sequestration projects that can create CERs.

Afforestation projects are projects that establish forests on lands that historically were non-forested. Reforestation projects establish forests on lands that previously were forested, but have been converted to non-forest uses.[77]

One of the key challenges associated with implementing A/R projects is assuring that carbon removed by biological processes, such as the growing forests or grasslands, is permanent and will not be reemitted as a consequence of fire, disease, die-off, timber harvesting, and other activities.

In the CDM, the challenge posed by the "impermanence" of A/R offsets was addressed by requiring A/R projects to be issued only temporary offset credits, referred to as "temporary CERs (tCERs) or long-term CERs (lCERs). Temporary credits issued for A/R projects eventually must be replaced by permanent credits. *Temporary CERs* expire at the end of the commitment period following the one in which they are issued, and *lCERs* expire at the end of the crediting period for the project.[78] It appears that the temporary crediting approach adopted by the CDM has been a predominate cause for A/R activities failing to become a significant CDM offset project category, and of the lack of market interest in this type of project.

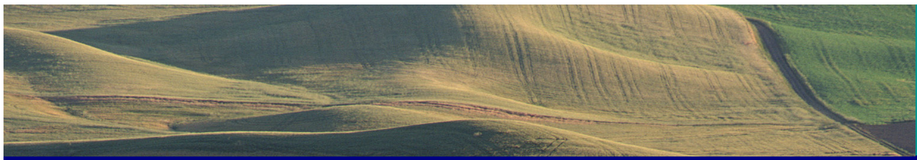
In addition to the temporary crediting issue, other factors have contributed to the lack of interest in A/R projects. In particular, the EU ETS prohibited use of CERs from A/R projects for compliance with its CO_2 emissions targets, so there is virtually no EU demand for A/R-based CERs. In addition, these projects face institutional and procedural challenges to their implementation, and challenges associated with their comparatively small scale and high cost.

This case study provides details on the issue of impermanence in the context of CDM A/R projects. It explores the CDM's approach to addressing impermance, and how this reduced market interest in CERs from these activities. It also discusses other elements of A/R projects which have challenged project developers, and which may have contributed to reduced market interest in these kinds of offset projects.

5.1 Impermanence

Emission reductions generated by actions such as fuel switching or using more efficient technologies are permanent since they cannot be reversed after they have occurred. Once those actions have been taken, GHG emissions are avoided, and no subsequent action is required to ensure the emission reductions are permanent.

In contrast, the removal of GHGs from the atmosphere by biological processes, such as carbon sequestration in forests or agricultural soil, is *impermanent*. Once carbon is sequestered, it must be maintained (i.e., stored) through time, so as to continue to provide atmospheric benefits.[79] Unlike permanent emission reductions, the impact of sequestered CO_2 on the atmosphere is contingent on actions and events subsequent to the actual sequestration period. If sequestered carbon ultimately is released back to the atmosphere, the benefits of the project are negated.[80] Such releases are termed



"reversals." The topic of "permanence" (also referred to as "impermanence") relates to the risk that emission reductions from sequestration projects will not be permanent.

Reversals in agriculture and forestry sequestration projects may be *unintentional* or *intentional*. Unintentional reversals result from natural and unpredictable events. Agricultural soil sequestration can be reversed by flooding and pest infestation. Sequestration by afforestation, reforestation and forest management projects can be reversed by fire, pests, disease and storm damage.[81] Such reversals may be catastrophic, and generally are beyond the control of a project developer. For example, a wildfire can release all of the carbon sequestered in a stand of trees.

In contrast, intentional reversals result from decisions by project owners, and are avoidable. For example, after implementing reduced-till cropping project to sequester carbon and receive offset credits, a farmer may choose to switch back to conventional tillage practices, releasing previously stored carbon. Similarly, an owner of forest land who undertakes an afforestation, reforestation or forest management project to receive offset credits later may opt to harvest timber, or revert to conventional rotation lengths and harvesting practices.[82]

5.2 Temporary crediting

One approach that has been used to address potential reversals is to identify these offsets as temporary or "rented" in an offsets registry account and have them expire in the registry after a defined period.[83] At the time of expiration, the buyer (or current holder of the temporary offset) must buy new offsets to replace the expired offsets. For accounting purposes, reversed offsets could be counted as emissions and added to the offset buyer's/holder's GHG emission inventory in the year in which the reversal occurs.[84] Instead of being required to purchase permanent offsets to replace the expiring offsets, the buyer/holder could have the opportunity to renew the expiring temporary offsets by ensuring the sequestered carbon remains stored. For example, the buyer might be required to buy a permanent easement, or pay for ongoing maintenance of the sequestered tonnes to ensure their continuing validity. This flexibility effectively would allow some temporary offsets to become renewable, and therefore similar to permanent offsets.

This approach effectively would allow buyers to postpone the purchase of permanent offsets. Temporary offsets typically would be priced at a discount to permanent offsets, taking into account the present value of replacing the temporary offsets at the end of the rental term, and assuming that the real price of offsets increases over time.[85] The duration of the contract plays an important role in the size of the discount. Longer contracts will have smaller discounts than shorter contracts, since longer contracts postpone the purchase of replacement credits for a longer period. However, the discount also depends on the expected rate of increase in offset prices. If prices are expected to increase significantly (i.e., more than the interest rate) over time, it will be costly (in present value terms) to replace temporary offsets; as a result, they may have little value.[86] Low prices for temporary offsets could discourage landowners from undertaking sequestration projects, particularly if transaction costs are significant.[87] On the other hand, if offset prices are expected to increase at rates lower than the interest rate, rentals would become attractive because the present value of a postponed purchase of a permanent offset would be lower than the current price of a permanent offset. The present value of future offset prices could be lower than current offset prices if breakthrough technologies are developed that achieve substantial GHG emissions reductions cost-effectively.[88] Finally there is a concern that temporary carbon offset credits will not be fungible with other carbon assets and instruments that are being traded in the evolving global carbon markets.

As noted above, buyers may be given the opportunity to provide maintenance payments to farmers or forest managers to ensure continued storage of sequestered carbon for which offsets already have been issued. If this option is available, there is a risk that farmers or forest managers will not comply with ongoing project monitoring and reporting requirements. They may abandon the project or simply stop reporting. They may also refuse to compensate for reversals if these occur long after they have received the last revenue from offset sales.

One potential solution might be to require buyers/holders of expiring temporary offsets who wish to renew those offsets to buy an easement from the farmer or forest manager, thus ensuring continued storage of carbon. Alternatively, buyers/holders of expiring temporary offsets could be required to purchase the land, take credit for only a fixed percentage of likely carbon sequestration, and then give the land to the government or a land trust for perpetual holding.[89] The latter approach would address both the risk of intentional reversals and – through partial crediting – the risk of unintentional reversals.

"Voluntary" offset programs such as CAR, ACR[90] and VCS[91] have devised other approaches to address impermanence that effectively treat sequestration offsets as permanent thereby avoiding some of the challenges associated with temporary crediting. The CAR and VCS require sequestration to be maintained for 100 years, while ACR requires sequestration to be maintained for 40 years. In addition, all three programs require forest carbon projects to set aside a portion of their offsets in "buffer reserves" that can be used to address reversals,

5.3 Temporary crediting in CDM A/R projects

The CDM adopted a temporary crediting approach for A/R projects.[92] Project participants may choose to be issued tCERs or lCERs. Restrictions on when these instruments expire and must be replaced after they have been used for compliance are expressed in terms of *crediting periods*. Restriction on when these credits can be used for compliance or banked is expressed in terms of *commitment periods*. The crediting period during which an A/R project may create offsets in the CDM is either: (i) 20 years, with up to two renewals; or, (ii) 30 years, with no renewal option.[93] Commitment periods are defined in an international climate agreement. For example, the first KP commitment period is 2008-12.

A project developer's choice between being issued tCERs or lCERs is fixed and cannot be changed for the duration of the project's crediting period, and, if applicable, the renewal of the crediting period. For example, if a project developer chooses to be issued tCERs, the project cannot be issued lCERs, whether or not the crediting period is renewed.

Temporary CERs expire at the end of the commitment period subsequent to the commitment period in which they were issued. For example, tCERs issued during the first KP commitment period would expire at the end of the following commitment period. Long-term CERs expire at the end of the crediting period in which the lCERs were issued. The crediting period for A/R projects is either: (i) 20 years, renewable twice; or, (ii) a single, 30-year crediting period. Thus, lCERs would not have to be replaced for 20 or 30 years. In addition, lCERs must be used for compliance during the commitment period in which they are issued, and cannot be carried over into another commitment period, even if the crediting period for the project ends in a later commitment period.[94]

In contrast to the approaches used by ACR, CAR and VCS to "permanently" credit A/R projects described above, there is no option for avoiding expiration in the CDM. Retired tCERs and lCERs must be replaced by other KP compliance units before the end of their expiration period. For this purpose, national emissions registries must have tCER and lCER replacement accounts in which valid Kyoto units[95] are cancelled to replace expiring tCERs and lCERs.

The issue of temporary crediting is clearly one of the reasons that only 18 A/R projects had been registered in the CDM as of the end of 2010 – compared to a total of approximately 2,700 registered projects. And, as noted above, the EU ETS prohibition on the use of CERs from A/R projects effectively eliminated demand for these credits by the largest group of private sector buyers in the CER market. Demand from other private sector buyers for A/R project credits appears to have remained limited, judging from the number of A/R projects that have been registered to date, and the fact that the majority of registered A/R projects appear to have been contracted either by the World Bank or government buyers.[96] This low demand from private sector buyers may be due to buyers' reluctance to take on the liability for replacing credits in the future, which likely has led some to discount the value of A/R CERs to a level below the minimum asking price for sellers in the market, and others to completely rule out buying tCERs and lCERs. Limited demand also may be due to the difficulty of predicting future prices at which buyers of tCERs or lCERs would need to replace temporary credits with permanent credits.

5.4 Challenges relating to reversals and infrequent verifications

In addition to the challenges associated with reversals, A/R projects pose other risks that are not associated with other offset project types. For example, after the initial project verification, additional verifications must take place every five years throughout the crediting period.[97] This long interval between verifications and subsequent issuances of CERs, which typically occur annually or more frequently for other project types, means it takes longer for A/R project developers to receive tCERs or lCERs than CERs from other project types. This consideration, in conjunction with the small scale and high cost of many A/R projects, are likely factors that have contributed to the relative unpopularity of A/R projects.

5.5 Other institutional and procedural challenges for CDM A/R projects

As part of its efforts to help develop and support the CDM market by creating different carbon funds that foster learning about important offset project types, the World Bank has been one of the most important buyers of offset credits and developers of CDM A/R methodologies and projects. Based on this experience, the World Bank has highlighted a number of institutional and procedural issues that challenge A/R projects, including:[98]

1. The modalities and procedures[99] for A/R projects were created later than in other sectors in the CDM, thereby delaying the development and approval of A/R methodologies. In addition, the methodology approval process was lengthy and stringent;
2. A/R methodologies involve myriad and complex requirements;
3. During project preparation, the selection of an appropriate methodology is difficult because applicability conditions are unclear and overlap between methodologies. In addition, the large amount of information required to calculate the emissions baseline and demonstrate additionality often is unavailable;
4. Validation of projects has been delayed due to multiple methodology revisions;
5. Project developers do not have sufficient capacity to understand CDM requirements for A/R projects, and requirements for supporting documentation increases delays;
6. Increased experience with A/R projects and simplified methodologies[100] helped reduce A/R project preparation time from 3.9 to 1.4 years on average after 2007. However, validation and registration timelines have remained the same, and A/R projects spend three years on average in the CDM project review and credit issuance cycle.

The World Bank also points out a number of other challenges facing CDM A/R projects relating to the CDM's land eligibility issues, and the complexity of GHG accounting for A/R projects. With respect to temporary crediting, the World Bank notes that all of its BioCarbon Fund projects opted to be issued tCERs, due "to the long life of lCERs which prevents developers from taking advantage of carbon price speculation."[101] It also notes that temporary credits may not be renewed beyond a project's crediting period, limiting the carbon sequestration that would be achieved by some projects.

International A/R projects face a number of significant institutional and procedural challenges, as noted by the World Bank. They also face several other problems specific to these project types, not limited to the long time it takes for afforestation projects to be implemented, for trees to grow, and for credits to be received. These problems are in addition to the high cost to develop projects and the fact that these projects frequently are small scale. Given these challenges, it appears to be a positive development that offset programs such as CAR, VCS and ACR have decided to adopt a permanent crediting approach for A/R projects. This approach could serve as a model that could be used in a potential future U.S. offset program. It will be critical for such an approach to address permanence concerns and the risk of removals effectively. The review presented here suggests a temporary crediting approach was a barrier to the development of a robust market for CERs created by A/R projects in the CDM. In order for A/R to realize its potential as a cost-effective source of international offsets, permanent crediting is likely to be necessary.

5.6 Applicability to a U.S. offset program

In EPA's economic modeling of federal cap-and-trade legislation debated in 2009 and 2010, the agency concluded that forest management could account for approximately three-quarters of the total U.S. domestic offset supply in 2015 at prices of \$11-14/tCO_2, and approximately two-thirds of the domestic offset supply in 2020 at prices of \$14-18/t CO_2.[102] EPA's estimates also suggest afforestation will account for most of the remaining domestic offset supply. Based on EPA's analysis, the success of a U.S. domestic offset program may depend on its ability to foster creation of significant amounts of cost-effective offset credits derived from forestry projects. Therefore, lessons learned from experience with forestry projects in the CDM are important for U.S. policymakers to consider.

As discussed above, the CDM's temporary crediting approach likely has been a significant cause of A/R activities failing to create large quantities of CERs. The need to replace temporary credits in the future, and the difficulty predicting future prices at which temporary credits would have to be replaced, likely have discouraged many non-European buyers from investing in tCERs or lCERs from A/R projects. Furthermore, since CERs from A/R projects are not eligible for compliance purposes in the EU ETS, there is virtually no demand for A/R-based CERs in the EU.

Existing voluntary offset programs have abandoned the temporary crediting approach. In its place, CAR, VCS and ACR have adopted an approach which treats sequestration offsets as permanent while requiring that sequestration be maintained for up to 100 years, and that all projects set aside a portion of their offsets in buffer reserves to address potential reversals. Federal cap-and-trade legislation debated in 2009 and 2010 also included provisions requiring issuance of permanent offsets for sequestration activities, and establishing mechanisms to address potential reversals, such as an offset reserve or insurance requirements.

If U.S. policy-makers maintain their preference for a permanent crediting approach for sequestration projects, this would eliminate an important barrier to future development of forest carbon sequestration projects. However, forestry projects face other challenges that may prevent them from creating offsets at the low prices estimated by EPA. For example, forestry projects can experience unintentional reversals and lose some of their offset credits. This makes them potentially riskier than other project types. In the CDM, verification of A/R projects occurs every five years delaying CER issuance, as compared to other types of offset projects. The concomitant delay in the realization of economic returns from A/R projects is compounded by the time it takes for these kinds of projects to be developed and for trees to grow. Another challenge for U.S.-based forestry projects is that project baselines, relevant BAU practices and applicable legal requirements vary significantly by region and within regions. This variation in baseline conditions may make it extremely difficult to apply standardized approaches for forestry projects, despite the preference for standardized additionality tests and baselines reflected in provisions of previous U.S. cap-and-trade legislation. To address this variation, a U.S. offset program may create complex eligibility requirements, and even require the use of a financial additionality tests similar to that incorporated in the CARB's U.S. forest projects offset protocol. If these elements are included in future forest offset protocols they could contribute to delays and uncertainties in the project approval process similar to those experienced by A/R projects in the CDM.

In addition to this set of challenges, there simply may not be enough marginal land available in the U.S. to grow trees to create offset supplies consistent with EPA's estimates. Furthermore, experience to date undertaking larger-scale forest management projects is limited, and the development of protocols and policy frameworks that may set the stage for widespread CO_2-based forest management are still in their infancy. Finally, the costs of forest management projects may be significantly higher than the \$11-18/tCO_2 estimated by EPA. One recent study showed that break-even carbon prices for forest management projects could be in the range of \$35-50/tCO_2e based on the CAR protocol and \$45-160/tCO_2e under the VCS protocol in the "all eligible pools" scenario.[103] If these prices are more representative than EPA's offset price estimates, forest management projects may play a much smaller role in a future U.S. cap-and-trade program than has been envisioned.

6. Renewable Energy Projects

Renewable energy projects account for about 45% of the projects in the CDM pipeline, the majority of which are hydropower (aka "hydro") and wind projects.[104] In early 2009, the EB expressed concerns related to the electricity tariff value used by project developers to demonstrate the financial additionality of wind projects located in China – a concern that extended to hydro projects in late 2009 and early 2010. In response to these concerns, the EB issued a high number of requests for review based on the view that these projects were being assessed using a lower tariff than the actual tariff that had been observed in the region. The use of the lower tariff called into question the additionality of these projects and the motives for lowering the tariff. According to the Institute for Global Environmental Strategies (IGES), over 10% of requests for review of wind and hydropower projects were due to issues relating to the tariff, and close to 50% of the projects reviewed for these reasons were rejected by the EB. This case study explains the EB's concerns related to the tariff, particularly in the context of wind projects in China, and the broader policy issues behind these concerns.

6.1 Additionality issues

The EB's concerns regarding the financial additionality of wind and hydro projects in China relates to the tariff or electricity price (Renminbi [RMB]/kWh) used by project developers to demonstrate project additionality using the investment test. The EB observed that the tariff used for wind projects requesting registration in 2009 was lower than tariffs used historically by similar projects in the region. It also observed that if the highest tariff were applied, many of these projects might not be additional – i.e., the projects might not have required revenues from the CDM to have been financially viable. Moreover, the EB was concerned that the higher tariffs witnessed in the past were due to government policies that gave a comparative advantage to one technology over another. These policies, known in CDM parlance as "Type E+/E- policies," are required to be considered in the process of determining the baseline scenario. This same concern extended to hydro projects in late 2009 and early 2010.

The EB defines Type E+ policies as "national and/or sectoral policies or regulations that create policy-driven market distortions which give comparative advantage to more emissions-intensive technology or fuels over less emissions-intensive technologies or fuels." The EB defines Type E- policies as "national and/or sectoral policies or regulations that create policy-driven market distortions which give comparative advantage to less emissions-intensive technologies over more emissions-intensive technologies."[105] The EB has decided that any changes to these policies that are relevant to a project must be taken into account in the baseline assessment. As discussed below, this entails providing a history of tariffs applicable to the project, which helps to provide a basis for determining additionality.

The EB requires DOEs to assess the changes in tariffs that have been paid historically for electricity sourced from wind projects, and the national policies and regulations that might have influenced them. The policies are to be accounted for in determining the project's additionality, and the suitability of the tariff used for the investment test. The EB has reminded DOEs to carry out a detailed assessment of the tariff and whether any applicable policies are type E+/E-.[106]

To assess whether China's policies have favored wind power, it is important to consider the evolution of the tariff paid for wind energy. China provided heavy incentives to the wind energy industry during its nascent stage, mainly in the form of high tariffs through subsidies, or access to official development assistance (ODA) from industrialized countries.[107] According to the China-Danish Wind Energy Development Program Office, there were four distinct stages in the development of the Chinese wind energy sector and the related tariffs:[108]

1. **Pilot stage (1986-1993**): The first grid-connected wind farm was built in 1986 with foreign equipment and investment, and government funding. The tariff was benchmarked against the tariff received by local coal-fired power plants.
2. **Industrialized stage (1994-2003):** China commenced development of domestic technology and the policies to support its development. Grid companies were required to facilitate the connection of wind farms to the grid and purchase the electricity at a tariff that would be determined based on power generation cost, loan repayment, and reasonable profit. Any difference between the calculated tariff and the tariff for electricity from other sources was to be absorbed by the grid company. The final tariff was negotiated in the Power Purchase Agreement (PPA) stage and had to be approved by the government.
3. **Scaling up and turbines localization stage (after 2003):** Tenders were held to promote competition in the development of wind farms, and to establish a tariff through market mechanisms. Two approaches for determining the tariff were developed – government-approved tariffs[109] and tariffs based on tenders.[110]
4. **Current situation:** Tariffs are approved based on centrally guided electricity tariffs, or benchmarks. At the end of July 2009, the National Development and Reform Commission (NDRC)[111] published benchmark tariffs per region,[112] which, according to the report, "improved the policy for wind farms tariffs."[113] The final tariff is negotiated at the PPA stage, and is usually below or equal to the benchmark tariff.

It is likely the feasibility studies for many of the wind projects in the CDM were undertaken towards the end of stage two and during stage three. This implies there could have been a difference between tariffs for different projects. The changes in tariffs – which first were introduced in 1986, long before the start of the CDM – appear to reflect a typical progression of policies. These policies may have been intended initially to encourage the development of wind technologies and projects, and then to gradually reduce or eliminate subsidies as the technologies and projects became more economically competitive.

In contrast, the EB has been concerned that China's removal of subsidies for renewable power generation favored more emissions-intensive technologies over wind, and that the government's motives were to shift support for wind projects from the government to the CDM. In the EB's view, projects for which subsidies were eliminated would appear incorrectly to be additional based on the investment test.[114] Based on this reasoning, the lower tariff would influence the IRR results, making the projects appear to be less financially attractive, thus motivating developers to develop these projects as CDM projects. In this context, subsidies for these projects would decrease over time as the energy sector was reformed, and grid companies moved from national to provincial ownership. In view of these concerns, the EB requested review of many wind projects. DOEs and project participants were unable to provide substantial evidence to convince the EB of the suitability of the tariffs, in part because the EB has not provided clear guidance on how to properly assess them. Instead, at its 55th meeting (July 26-30, 2010), the EB decided that the suitability of tariffs used in investment tests for Chinese wind projects would be assessed on a case-by-case basis.[115] Given the lack of guidance, and the EB's previous decisions requiring the highest tariff value to be used to assess wind projects, DOEs and project participants have resorted to revising the investment test using the highest tariff historically observed in the region in an effort to secure registration. Projects that failed to maintain their additionality based on this tariff level were rejected.

This outcome may not be justified, as the history of Chinese wind projects shows different tariffs were applied at different times and in different circumstances. For example, as discussed below, higher tariffs were applied to some pilot projects for specific reasons, and these high tariffs were not applied to other projects.

For example, the EB has questioned the tariff used by CDM projects in Heilongjiang Province. According to the EB,[116] the highest tariff witnessed in the Province is 0.79 RMB/kWh, while CDM projects have used much lower tariffs of 0.50-0.60 RMB/kWh. However, the higher tariff is based on two demonstration projects, and likely was higher than the actual tariff received by the projects.[117] The tariff for these demonstration projects likely was higher due to the demonstration nature of these projects, and their objective to promote development of wind farms in the region. Nevertheless, the EB required projects in this region to revise their investment tests to use the higher tariff value.[118] This was the case for UNFCCC Project No. 2776 "Heilongjiang Dabaishan Wind Power Project,"[119] which was rejected by the EB, because the IRR surpassed the financial benchmark based on the higher tariff.

The wind energy sector in China has gone through many stages of development as described above. The policies introduced to encourage the sector's development pre-dated the CDM, and changes to them appear to reflect a progression of policies associated with subsidizing new industries until they are mature enough to compete without subsidies or with less generous support.

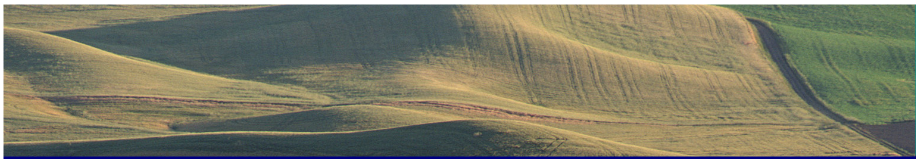
The EB has expressed the concern that policy changes and reductions in tariffs paid for electricity generated by hydro and wind projects were motivated by an intention to shift the cost of subsidies to the CDM. The International Emissions Trading Association (IETA) has suggested this is a troubling signal to the offsets market and could deter investment in clean energy technology.[120] The EB's decision not to provide guidance on the treatment of E+/E- policies for determining a project's additionality (and baseline scenario), and its approach to assessing the suitability of the tariff on a case-by-case basis, appears to render many Chinese wind projects ineligible under the CDM. These actions force project developers to use higher tariff values for the project investment test than the tariffs the projects received when they were implemented. This effectively may exclude many additional projects, unless they can demonstrate additionality using the higher tariff. In addition, it sets a precedent that project developers and investors undoubtedly will consider in the future regarding how and whether government policies may change before they implement a CDM project. The associated uncertainties may be detrimental to the further development of wind projects in China.

6.2 Applicability to a U.S. offset program

In a U.S. cap-and-trade program as it has been conceived to date, renewable energy projects would *not* be eligible to create GHG offsets because GHG emissions from the electricity generation sector are expected to be covered under a cap-and-trade program. Instead of producing offsets, renewable energy would serve to displace emissions from fossil-fired electricity generation, and would become more price-competitive due to the carbon price imposed on emitting sources. Electric companies would be able to reduce their compliance obligations by sourcing part of their electricity from renewable energy sources.

Renewable energy producers also could be eligible to receive tradable Renewable Energy Credits (RECs) under a Renewable Portfolio Standard (RPS) program. For example, California's RPS program will operate alongside its GHG emissions trading program when compliance obligations for the latter start in 2013.

Given that renewable energy is not likely to be an offsets category in the U.S., experience with the regulatory treatment of CDM wind projects is not directly applicable in the U.S. context. However, some issues relating to CDM wind projects may be relevant to a U.S. offset program, including: (i) whether certain project types or technologies such as WHR that receive subsidies or other incentives designed to increase their development and deployment (such as those described in section four) should be considered additional; (ii) how to determine whether they are additional; and, (iii) whether projects should not be considered additional if the government decides to stop providing a subsidy. Such questions also could arise in the context of other project types, such as landfill gas.



7. HFC23 Destruction Projects

The first methodology approved by the CDM was a methodology for projects that destroy trifluoromethane (HFC23) by incineration. HFC23 is a byproduct of manufacturing another gas – HCFC22. This methodology only applies to existing facilities which: (i) have been operating for at least three years between January 1, 2000 and December 31, 2004; and, (ii) operated from 2005 until the start of the project.[121] In developing countries, HFC23 emissions from these activities typically are uncontrolled, and are vented into the atmosphere. HCFC22 is used in air conditioners and as a feedstock for certain plastics, and is manufactured in part to replace refrigerants (CFCs) that were phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer (MP).

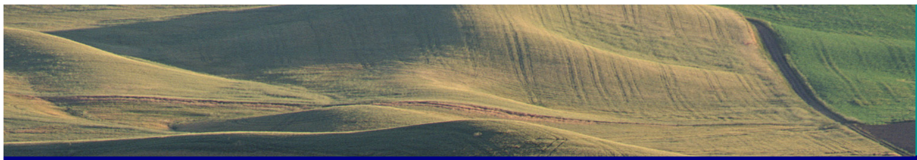
HFC23 is an extremely potent GHG, with a global warming potential (GWP) of 11,700 as compared to carbon dioxide which has a GWP of 1. Given this high GWP and the large scale of many of the facilities which produce HFC23 emissions, HFC23 destruction projects create large quantities of CERs. In addition, HFC destruction technology is not complex, and associated emission control costs are lower than for many other offset projects, making these projects financially attractive to implement under the CDM. HFC23 emission reductions also are relatively easy to measure. These projects also are among the most "additional" of any CDM project type. There is no reason to implement HFC23 destruction projects in the absence of the financial incentive to sell GHG offsets. Without the CDM, these GHGs would continue to be freely vented into the atmosphere. Finally, concerns that the CDM provided perverse incentives to create new HCFC22 facilities were addressed in large part by the CDM limiting project eligibility to existing plants. Thus, the additionality of these emission reductions generally is clear and straightforward to demonstrate, making project approval simple in principle. Other issues have been raised relating to the additionality of some of the emissions reductions claimed for HFC23 projects, and related methodological issues which are discussed below.

The attractiveness of HFC projects was borne out in 2005, when CERs created by these types of projects accounted for 67% of the offset volumes contracted.[122] Subsequently, HFC projects' share of the market declined to 34% in 2006,[123] 8% in 2007,[124] 3% in 2008,[125] and a negligible (unspecified, but less than 3%) share in 2009.[126] Given that HFC23 projects are high-volume projects (e.g., one project is projected to be issued more than 50 million CERs by the end of 2012[127]), this category is projected to account for between 17% and 25% of all CERs issued by the end of 2012.[128] Nevertheless, because of their significant market share early in the program and the limited number of CERs that have been issued to date, HFC destruction projects accounted for 50% of all CERs issued by the end of 2010. More recently, the CDM has been dominated by less controversial project types – including renewables and energy efficiency. In 2009, renewables accounted for 43% and energy efficiency/fuel switching accounted for 23% of traded CERs.

7.1 Controversies relating to HFC23 projects

While HFC projects have been an important source of CDM offset supply, particularly in the early years of the CDM market, they have been controversial, and several arguments have been made by critics of these projects. One prevalent argument was the CDM provided an incentive to increase HCFC22 production to create offsets. However, the offsets issued from these types of projects are based on the historic rate of HFC23 generation not current levels, and are limited to reflect HCFC22 production capacity in 2004. Thus, this argument does not appear to be valid.

Another argument made against HFC projects and their eligibility to create CERs has been that the costs of abatement for these projects represent only a fraction of the prices paid to project developers, and that this is a highly inefficient use of scarce resources available to invest in emission reductions in the developing world.[129] However, the objective of the CDM was not to limit eligible emission reductions to those with higher costs of abatement. It was to "assist Parties not included in Annex I in achieving sustainable development and in contributing to the ultimate objective of the Convention [the UNFCCC], and to assist Parties included in Annex I in achieving compliance with their quantified emission limitation and reduction commitments under Article 3."[130] Given this objective, the CDM worked as intended with respect to HFC23 projects. Projects with the lowest abatement costs and well-understood technologies were developed first. Buyers determined if the price and volumes of CERs generated by these projects was "right" based on their own evaluation of the prices and volumes of alternative abatement options, such as reducing emissions in their own assets, or purchasing other compliance instruments in the market. Since only a limited number of HCFC22 facilities were operating globally, most of the potential HFC23 destruction projects already have been implemented.



Another argument made against these projects has been that sellers received exorbitant economic rents (i.e., made too much profit) on HFC23 emission reductions, given their low marginal costs of abatement. This argument appears to reflect fundamental opposition to market mechanisms which use financial incentives to minimize overall abatement costs, and which are designed to reward the most cost-effective abatement activities.

Other critics of HFC23 projects suggested these projects should be excluded from the KP's flexible mechanisms because of their economic inefficiency, and instead HFC23 emissions should be reduced through application of a dedicated fund, like the one created under the MP.[131] However, this option was not under consideration by the international community at the start of the CDM. In the intervening decade, as much as 476 $MtCO_2e$ of emissions from HFC23 activities will have been avoided as a result of the CDM.[132] In addition, China applied a high tax on project developers' revenues from HFC23 destruction projects (65%) and nitrous oxide (N_2O) destruction projects (30%). Revenues from these taxes were used to fund sustainable development projects and activities. These benefits often have been overlooked by critics of HFC23 projects.

7.2 Methodological issues and other controversies related to HFC23 projects

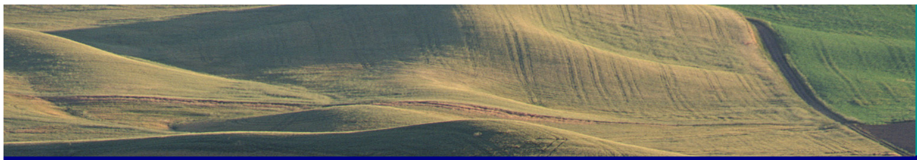
The EB approved the first version of the HFC23 methodology in September 2003, and the methodology was revised with minor clarifications in early 2004. In its subsequent assessment, the Meth Panel concluded that the methodology could create perverse incentives to increase HCFC22 production to generate more CERs, thereby undermining the MP. In light of this conclusion, the EB placed version 2 of the methodology on hold until the Meth Panel introduced a new version. In early 2005, the methodology was revised to restrict eligibility to existing plants, to establish the maximum eligible level of HCFC22 production for any eligible plant, and to establish a waste generation rate (i.e., the ratio used to estimate the amount of creditable HFC23 generated per tonne of HCFC22 produced).

The restrictions related to plant eligibility were introduced partly to address concerns that the CDM would undermine the goals of the MP. The Meth Panel limited the applicability of the methodology to existing plants – specifically, plants that had "at least three years of operating history between the beginning of year 2000 and the end of year 2004."[133] Any plant not meeting this requirement is considered a new plant. The COP/MOP[134] further expanded the definition of a new plant to refer to new increases in production capacity in plants with at least three years of operational data.[135] The EB has rejected requests made by project developers to expand the applicability of the methodology to new plants. New plants currently are not eligible to generate CERs under the CDM. Discussions related to including new plants in the CDM in the future have been postponed repeatedly, but eventually may take place.

The revision of the methodology also limited the maximum production amount of HCFC22 that can be used as the basis to claim CERs to the maximum historic production level achieved in the last three years the plant was fully operational between 2000 and 2004. The revision results in the crediting of emission reductions based on the lower of: (i) a 3% HFC23 waste generation rate; (ii) the rate based on three years of operating data; or, (iii) the actual rate at the time of project verification. These limitations were introduced to address concerns that plant operators might increase HCFC22 production to create more CERs.

Critics of the CDM have questioned whether these provisions have been effective. In March 2010, CDM Watch submitted a request for revision of methodology AM0001.[136] Following an analysis of monitored data available for registered HFC23 destruction projects, CDM Watch concluded HCFC22 plants were operating in a "manner to maximize the production of offset credits".[137] According to the request for revision, the methodology prevented operators from reducing the waste generation rate. It also argued that the production cap was not effective, and prolonged the operation of production lines beyond their operational lifetime (i.e., plants that may have shut down would continue to operate because replacing them would render them ineligible under CDM). The proposed methodology revision sought to address this issue by introducing a lower waste generation rate of 0.2%.

This proposed revision was dramatic, and as expected, the Meth Panel did not recommend that the EB approve it. However, the Meth Panel did request the EB to consider capping the waste generation rate at a lower level than the 3% stipulated in the methodology. While the EB did not agree to this request, it asked the Meth Panel to carry out a comprehensive study to assess whether the baseline emissions calculated using AM0001 accurately represented BAU.



The findings of the study were considered at the EB's 58th meeting (November 22-26, 2010). The Meth Panel concluded that the methodology creates a disincentive to implement operational measures to reduce the actual waste rate below the capped level established in the PDD.[138] However, it also found that the methodology does not create a perverse incentive to increase production of HCFC22 to create more CERs. The Meth Panel also found the level of HCFC22 production that would be eligible to qualify to generate CERs was far below existing market demand for HCFC22.

Taking these findings into account, the EB requested the Meth Panel to prepare a revision of the methodology which it approved at its 65th meeting in November 2011.[139] The revision reduces the waste generation rate from 3% to 1%, thereby reducing by one-third the number of credits that can be earned by HFC23 destruction projects. This decision will affect registered projects when their crediting periods are renewed, and could result in developers of HFC23 projects choosing not to renew their crediting periods – particularly in light of the additional decisions described below.

In January 2011, the EU decided to ban the use of offset credits from HFC23 destruction projects in the EU ETS as of May 1, 2013. The EU also banned the use of credits from projects that destroy nitrous oxide (N_2O) from adipic acid production. These credits may be used for compliance through the compliance "true-up" for Phase 2 of the EU ETS in April 2013, but not thereafter.[140] In addition, Australia also plans to ban the use of these credits when its emissions trading program begins in 2015[141], and New Zealand also may ban their use in its existing emissions trading scheme.[142] Together, these decisions will significantly shrink the market for CERs from HFC23 destruction projects after 2012, and may eliminate it completely unless countries such as Japan agree to future emission reduction targets beyond 2012 and permit use of these credits for compliance.

7.3 Applicability to a U.S. offset program

As discussed above, HFC23 destruction has been one of the most important sources of CERs in the CDM market, potentially accounting for as much as 25% of all CERs issued by the end of 2012. This has been an attractive project type due to the scale of these projects, their low marginal cost of abatement and their clear additionality – i.e., in developing countries, HFC23 would not be destroyed at HCFC22 plants in the absence of the incentives created by the CDM.

In a U.S. cap-and-trade program, HFC23 destruction likely will not play the central role it has had in the CDM. As of 2009, HFC23 emissions in the U.S. were estimated to be only 5.4 $MtCO_2e$.[143] HFC23 emissions in 2009 decreased by 60% relative to 2008, and 85% relative to 1990, due to significant decreases in HCFC22 production and even more significant decreases in the HFC23 emission rate.[144] In 2009, only three HCFC22 plants were operating in the U.S., and all three used thermal oxidation to significantly lower their HFC23 emissions.[145] HCFC22 production in the U.S. is scheduled to be phased out by 2020 under the Clean Air Act because it depletes stratospheric ozone.[146]

Nevertheless, based on cap-and-trade legislation considered in Congress in 2009 and 2010, destruction of hydrofluorocarbons (HFCs) could play a role in a U.S. cap-and-trade program. The American Clean Energy and Security Act[147] (H.R. 2454), and the "Kerry-Lieberman" bill, both incorporated provisions that would create a separate trading program for HFCs. The program would cap and phase down HFC production and importation, and allow for the use of "destruction offset credits" to comply with the cap.

HFC23 destruction has been controversial in the CDM in part because some critics consider it less beneficial than clean energy and energy efficiency projects in terms of sustainable development – which is one of the objectives of the CDM – and too profitable for the owners of industrial gas plants and project developers. These issues may not be as controversial in the context of a U.S. cap-and-trade program, which likely will be aimed at reducing covered emissions cost-effectively, and which will not need to consider whether HFC destruction projects contribute to sustainable development in developing countries. In addition, allowing HFC destruction offset credits only to be used within a separate HFC trading program likely would alleviate potential concerns that such credits might "crowd out" other offset types that provide additional benefits beyond emission reductions.

8. Conclusion

Both economic research and market experience have demonstrated that offsets can significantly reduce the costs of compliance with a GHG cap-and-trade program. Nevertheless, experience with the CDM demonstrates that the quantity of offsets created by specific projects, and categories of projects, can be significantly lower than expected due to a variety of unanticipated issues. Some of the lessons learned from these CDM case studies may apply, directly and indirectly, to the development of a future U.S. offset program.

In addition to these issues, other unanticipated challenges and impediments to the development of a large-scale offset program can be expected to arise in the U.S. context. For example, offset "roadtesting" studies sponsored by EPA found that differences between offset protocols can cause the expected amount of offsets to be generated by a specific project to vary by orders of magnitude in some cases, and can make some projects uneconomic under certain protocols. As such, it will be important for U.S. policymakers to consider the potential impacts of different methodology requirements if they develop offset protocols and program rules in the future.

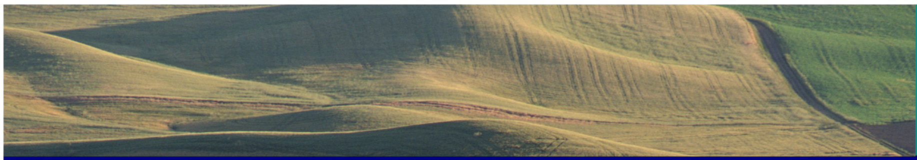
Some of the issues and lessons learned relating to CDM project types examined in these case studies may not be directly applicable in the U.S. because these project types may not be eligible to create offsets in a future U.S. program. In particular, renewable energy probably will not be an eligible offset project category because these projects displace emissions from electric power plants, which are likely to be covered entities under a future U.S. cap-and-trade program. It is also uncertain if LFG projects will be eligible in a U.S. offset program, because landfill emissions may be regulated (as in California), and policymakers may decide that allowing offsets to be generated in states that do not regulate landfill emissions would effectively punish states that already regulate these emissions. In addition, it appears the controversies that have affected HFC23 destruction projects in the CDM are less likely to reemerge in a future U.S. cap-and-trade program. Available emission reductions from HFC23 destruction in the U.S. are very limited, and federal cap-and-trade legislation debated in 2009 and 2010 only would allow the use of domestic HFC23 destruction credits to be used in an HFC trading program that would be separate from the broader economy-wide GHG cap-and-trade program. Nevertheless, given the EU's ban on the use HFC23 offset credits in the EU ETS, and discussion of similar bans in Australia and New Zealand, it is possible that a future U.S. cap-and-trade program also may ban their use.

Despite these exceptions, many of the lessons learned from the CDM case studies described in this paper are relevant to the design of any future U.S. offset program. For example, experience with CDM renewable energy projects – and questions relating to how government subsidies or other support, and removal of that support, affect additionality – may be relevant in the context of U.S. WHR projects. As discussed in section four, WHR projects have received support from the U.S. federal government in the form of tax credits, grants and loan guarantees to facilitate the adoption of CHP. If these projects are eligible to create offsets in a U.S. program, policymakers and offset buyers will need to consider and understand how government support, and the removal of that support, would affect these projects in terms of their additionality, baselines, and offset volumes.

Furthermore, if landfills in states that do not regulate landfill emissions are determined to be eligible to create offsets, some of the experience gained in the CDM will be important to consider. As discussed in section two, LFG methodologies in use in the U.S. appear to lack important guidance regarding which LFG model should be used to estimate baseline emissions. This may lead to significant differences between estimates of the amount of offset credits that may be created by these projects and actual credits issued, as experienced in the CDM.

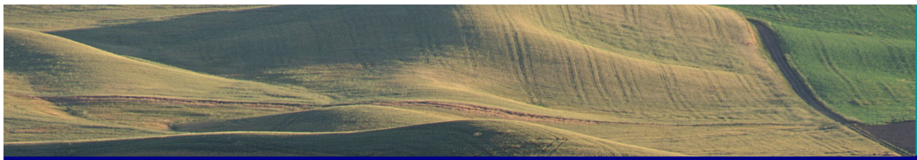
With respect to forestry carbon project, it appears that a U.S. offset program is not likely to rely on a temporary crediting approach, which contributed to a lack of market interest in A/R projects in the CDM. Nevertheless, these projects still may experience significant challenges, as discussed in section five. These may include some of the challenges experienced in the CDM, including infrequent project verifications which result in long delays between credit issuances and reduced project viability. In addition, forestry projects likely will encounter new problems in the U.S. context. For example, policy-makers may impose complex, project-specific eligibility requirements on these projects to ensure that regional variation in forestry projects is taken into account, as was done in the California offsets program. Other challenges include insufficient marginal land for development of large-scale forest carbon sequestration projects in the U.S., a lack of experience implementing large-scale forest carbon projects, and project costs which may significantly exceed those estimated by EPA.

The potential for unanticipated issues to reduce offset volumes significantly is particularly important for U.S. forestry projects, given that forest management and A/R projects are expected to be the largest contributors to U.S. domestic offset supply. As such, additional analysis of potential barriers to the widespread deployment of these projects, and options to address these barriers, appear to be warranted before a future U.S. offset program is developed.



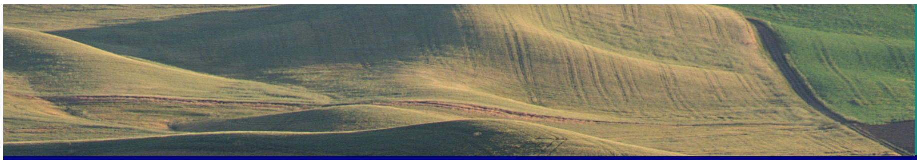
9. Glossary of Terms

ACR	The American Carbon Registry (ACR) is a voluntary offsets program and registry operated by Winrock International.
Additionality	The degree to which GHG benefits achieved by an emission mitigation project would not have occurred in the absence of the added incentive of creating GHG emission mitigation.
Afforestation	An activity included under Article 3.3 of the Kyoto Protocol; more generally, establishing new forests on land that has not ever, or in recent times, been forested.
Annex I countries, nonAnnex I countries	Countries listed, or not listed, in Annex I of the UNFCCC; Annex I is a list of industrialized countries, non-Annex I countries are developing countries.
A/R	Afforestation and reforestation.
ARB (or CARB)	The California Air Resources Board. ARB is the regulatory agency in charge of developing and implementing a CO_2 cap-and-trade program and an associated offsets program in California pursuant to the law known as "AB-32."
Baseline	The schedule of GHG emissions related to a project that would be expected to occur in the absence of a project.
BAU	Business As Usual.
CAR	The Climate Action Reserve. Previously known as the California Climate Action Registry. An offsets program and registry created originally by the State of California.
Clean Development Mechanism (CDM)	A provision described in Article 12 of the Kyoto Protocol that allows tradable credits, called CERs, to be generated through projects in developing countries that can be used by industrialized countries for compliance with their Kyoto commitments.
CDM Executive Board (EB)	The executive body that is charged by the UNFCCC COP to oversee the operation of the CDM.
Certified Emission Reduction (CER)	An emissions unit under the Kyoto Protocol that is issued under the procedures of the CDM.
Conference of the Parties (COP)	The main operational body of the UN-FCCC, representing all countries that have ratified the UN Framework Convention on Climate Change (UN FCCC). It meets annually.
Conference of the Parties serving as the Meeting of the Parties (COP/MOP)	The term used for the COP – both the body and its meetings – following the entry into force of the Kyoto Protocol. For example, the first COP/MOP, which was held in Canada in 2005, was the 11th COP and the first Meeting of the Parties to the KP.
DOE	Designated Operational Entity. A DOE is an independent, third-party auditing, accounting, engineering or similar organization accredited by the CDM Executive Board to validate projects and verify GHG emissions reductions associated with offsets projects.
EU ETS	The European Union Emissions Trading Scheme. A CO2 cap-and-trade program that covers 27 EU nations and which has been in effect since 2005.



Forest management	An activity included under Article 3.4 of the Kyoto Protocol; more generally, the management of forests to reduce emissions of carbon and/or increase the sequestration of carbon.
GHG	Greenhouse gas. This term usually is used to refer to the collection of all six types of GHGs regulated by the Kyoto Protocol (CO_2, CH_4, N_2O, SF_6, PFCs and HFCs)
GWP	Global Warming Potential. A number of gases contribute to the warming of the planet's atmosphere. Assigning each gas a Global Warming Potential (GWP) allows the emissions of different greenhouse gases to be compared using a single, common scale.
Kyoto Protocol (KP)	A protocol under the UNFCCC where, inter-alia, industrialized countries took on binding commitments to reduce their greenhouse gas emissions in a first commitment period (cp1), 2008-2012.
IPCC	The United Nations Intergovernmental Panel on Climate Change.
KP	Kyoto protocol. A protocol under the UNFCCC where, inter-alia, industrialized countries took on binding commitments to reduce their greenhouse gas emissions in a first commitment period (cp1), 2008-2012.
Leakage	A GHG effect occurring outside the boundary of what is being reported or accounted for a project or activity that, however, is caused by the project or activity and reduces its environmental benefit.
lCER	Long-term CER; a particular form of CER issued under the CDM for LULUCF A&R projects.
LFG	Landfill gas.
Methodologies Panel (aka Meth Pane)	An independent panel of experts established by the CDM Executive Board to evaluate proposed CDM offset methodologies and to make recommendations to the EB regarding approval or disapproval of proposed methodologies.
MP	Montreal Protocol on Substances that Deplete the Ozone Layer.
Offset	Emission reduction projects (often called "offset" projects) reduce GHG emissions and create "credits" that regulated parties required to limit their emissions potentially can use to comply with GHG emissions targets. GHG emissions offsets are emission reductions created by projects and activities at emission sources, and in economic sectors, not covered by a GHG emissions trading program's fixed emissions cap. These sources and activities may be located either within or outside the geographic jurisdiction of the trading program.
Permanence, non-permanence, reversal	Generally, the issue that removals of carbon from the atmosphere by biological processes, such as the growing of forests, are not permanent and can be reversed (i.e., sinks can become sources) as a consequence of fire, disease, die-off, timber harvesting, and other activities.
PDD	Project Design Document.
Reforestation	An activity included under Article 3.3 of the Kyoto Protocol; more generally, establishing forests on land that has in recent past times been forested but in more recent times has been under some other land use.

Removals	The sequestration of carbon from the atmosphere (the opposite of emissions); a process that does this is a "sink."
Sequestration	The absorption of carbon from the atmosphere by some process; normally of CO_2 but can be for other greenhouse gases (e.g., methane).
Sink	A process that removes carbon from the atmosphere (e.g., a growing forest).
Storage	Keeping sequestered carbon out of the atmosphere.
tCERs	Temporary CER; a particular form of CER issued under the CDM for LULUCF A&R projects.
The Carbon Market	An emissions trading market for greenhouse gas (GHG) emission units, sometimes limited to just CO2. Several distinct carbon "markets" operate around the world today, such as the EU's Emissions Trading Scheme (EU ETS).
UNFCCC	United Nations Framework Convention on Climate Change, the multilateral environmental agreement to address the risk of global climate change.
USDA	The United States Department of Agriculture.
US EPA or EPA	The United States Environmental Protection Agency.
VCS	Verified Carbon Standard (VCS). Previously known as the Voluntary Carbon Standard. An international voluntary offsets standard that operates an offsets program and registry.



10. End Notes

1. Robert Youngman and Richard Rosenzweig were respectively Director of Economic Analysis and Chief Operating Officer of Natsource, LLC from 2000 to 2011. Rina Cerrato, is Senior Director of Project Services at Natsource, LLC. Adam Diamant, Senior Project Manager, Electric Power Research Institute (EPRI) also contributed to preparation of this paper.

2. This paper is based on information presented in a comprehensive EPRI report entitled *Key Institutional Design Considerations and Resources Required to Develop a Federal Greenhouse Gas Offsets Program in the United States*. EPRI, Palo Alto, CA: 2011. 1023122.

3. *Emissions Offsets: The Key Role of Greenhouse Gas Emissions Offsets in a U.S. Greenhouse Gas Cap-and-Trade Program*. EPRI, Palo Alto, CA: 2010. 1019910, p. 1.

4. UNEP Risoe CDM/JI Pipeline Analysis and Database, November 1st 2011, http://cdmpipeline.org/publications/CDMpipeline.xlsx.

5. See (i) *Designing a Large-Scale U.S. Federal Offset Program: Policy Choices and Lessons Learned from the Clean Development Mechanism and Other Offsets Programs*. EPRI, Palo Alto, CA: 2011. 1023673; and, (ii) *Identification and Analysis of Institutional Barriers to Developing a Large-Scale Federal Greenhouse Gas Emissions Offsets Program in the United States*, EPRI, Palo Alto, CA: 2011, 1023122.

6. http://kerry.senate.gov/imo/media/doc/APAbill3.pdf.

7. EPA's analysis ("EPA Analysis of the American Power Act in the 111th Congress," June 14, 2010), appendix and data annex are available at http://www.epa.gov/climatechange/economics/pdfs/EPA_APA_Analysis_6-14-10.pdf.

8. The European Union Emissions Trading Scheme (EU ETS) is a mandatory CO_2 cap-and-trade system that has been implemented in the 27-nation EU. It has been in operation since 2005.

9. The average primary CER price was €9.90 (or $13.60) in 2007 according to the World Bank ("State and Trends of the Carbon Market 2008," May 2008, http://siteresources.worldbank.org/NEWS/Resources/State&Trendsformatted06May10pm.pdf); the average 2008-vintage EUA price in 2007 was €19.56 as reported by Point Carbon (www.pointcarbon.com; subscription required). The conversion of Euros to U.S. dollars is based on a rate of €1.00 = $1.37 implied in the World Bank's estimates for average primary CER prices in 2007.

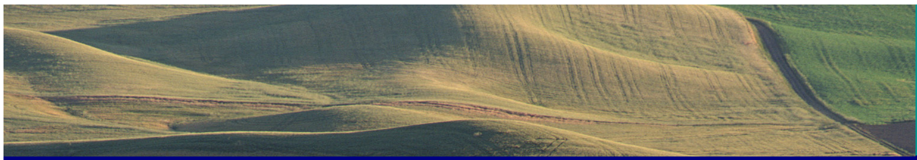
10. Natsource was recognized by New Energy Finance as the largest buyer of contracted carbon offset credits on a risk-adjusted basis through 2007. (New Energy Finance, Clean Energy League Tables 2007, February 2008, p. 20, http://bnef.com/free-publications/white-papers/1.)

11. In general, an offset project must demonstrate additionality by showing that: (i) the project creating the offsets was only undertaken because of the incentive provided by the offset program; and, (ii) the emission reductions would not have occurred but for the implementation of the project. Box 3 describes tests used by the CDM to determine the additionality of proposed offset projects.

12. For a complete discussion of the risks faced by offset project developers and buyers and ways to manage these risks, please refer to *Corporate Carbon Strategy and Procurement of Greenhouse Gas Emissions Offsets for Compliance with Mandatory Carbon Constraints*, EPRI, Palo Alto, CA: 2010. 1019911.

13. This risk can be assessed utilizing a variety of ratings, including those developed by Fitch, Standard and Poors, and Moody's (i.e., credit ratings for long-term foreign currency), as well as relative rankings from the World Economic Forum Global Competitiveness Index, the World Bank Foreign Direct Investment, and the Economist Intelligence Unit Sovereign Ratings.

14. A project must be registered, or approved by the CDM Executive Board, before it is eligible to create Certified Emission Reductions (CERs).



15. Landfill gas recovery: The low hanging fruit for carbon credits trading in the developing countries. Lee, CA, Bogner, JE, Aalders, E. http://www.go-worldlee.com/resources/landfill-gas2.pdf .

16. CDM projects must demonstrate "regulatory additionality" – i.e., that their activities and emission reductions are not required under any existing law or regulation to which the project is subject. See Box 3 for more information about CDM additionality tests.

17. To prove "financial additionality," a project developer must demonstrate that if revenue created by the project's offset credits were not available, the project would not be viable, or its rate of return would not be attractive. This approach assumes CERs created by the project are a decisive reason for undertaking a proposed project.

18. Issuance is the last step in the CDM project approval and credit issuance process. After an offset project has been registered, its emission reductions for a given crediting period monitored and measured, and a third-party auditing firm (a "Designated Operational Entity" (DOE)) has issued a report verifying the emission reductions, the CDM Executive Board (EB) reviews and, if appropriate, approves the report and issues CERs for that crediting period.

19. The PDD includes detailed information on the proposed project activity, and the baseline and monitoring methodology, including the plan for monitoring, reporting and verification (MRV). It provides the basis for subsequent decisions on validation, registration and verification of the project. The PDD must be "validated" by a DOE before the project can be registered by the CDM EB.

20. IGES CDM Project Database, December 1, 2010, http://www.iges.or.jp/en/cdm/report_cdm.html.

21. CDM registration reference #0165, 0167, 0799, 0925, as reported in IGES CDM Project Database, December 1, 2010, http://www.iges.or.jp/en/cdm/report_cdm.html.

22. CDM registration reference #0893.

23. CDM registration reference #0140.

24. Landfill gas capture: Design vs. Actual Performance and the Future for CDM Projects, http://siteresources.worldbank.org/INTLACREGTOPURBDEV/Resources/840343-1178120035287/EditedLFGWorkshopReportAugust14.pdf.

25. Landfill gas capture: Design vs. Actual Performance and the Future for CDM Projects, http://siteresources.worldbank.org/INTLACREGTOPURBDEV/Resources/840343-1178120035287/EditedLFGWorkshopReportAugust14.pdf.

26. Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site; http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-04-v5.pdf/history_view.

27. CDM registration reference #2028.

28. A monitoring report measures emission reductions from a CDM project for a specific crediting period. This report is reviewed by the DOE as part of the verification process.

29. The Climate Action Reserve (CAR) is an offset program that establishes protocols for GHG offset projects in North America. It provides oversight to independent third-party verification bodies, issues carbon offset credits known as Climate Reserve Tonnes (CRTs), and tracks issuances and transactions of credits in a publicly accessible offsets registry. In December, 2010, the California Air Resources Board (ARB) adopted four offset protocols originally developed by CAR to be used for compliance purposes by entities covered by the new California GHG cap-and-trade system implemented under AB-32 (the California Global Warming Solutions Act). These four compliance protocols include Forestry, Urban Forestry, Livestock Waste Digester, and Ozone Depleting Substances (ODS).

30. Anaerobic manure treatment is the storage or treatment of manure in the absence of oxygen.

31. For a comprehensive description of each of these digester systems, see "Anaerobic Digestion of Animal Wastes: Factors to Consider," National Sustainable Agriculture Information Service, http://attra.ncat.org/attra-pub/anaerobic.html.

32. The actual composition of the gas varies, depending on the composition of the treated waste. Methane may constitute roughly 50 to 75% of the gas. Carbon dioxide, nitrogen, hydrogen, hydrogen sulfide, water vapor are also typical components.

33. The majority of the projects in the CDM pipeline are claiming offsets only for the avoided release of methane. They indicate electricity generation as a potential plan for the future, but no offsets are being claimed for that activity.

34. Carbon Finance, "AgCert de-lists its shares," April 9, 2008, http://www.carbon-financeonline.com/index.cfm?section=global&action=view&id=11137 .

35. Reuters, "Carbon firm AgCert to delist in survival bid," April 4, 2008, http://uk.reuters.com/article/2008/04/04/agcert-delisting-idUKL0452516420080404 .

36. Tribune, "AgCert taken over by AES," June 29, 2008, http://www.tribune.ie/business/news/article/2008/jun/29/agcert-taken-over-by-aes .

37. World Bank, "State and Trends of the Carbon Market 2008," May 2008, p. 22, footnote 33, http://siteresources.worldbank.org/NEWS/Resources/State&Trendsformatted06May10pm.pdf .

38. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st, 2011.

39. The most common type of anaerobic digester used is covered lagoons.

40. The majority of the projects in Mexico are implemented in collaboration with AgCert, which has offices in Mexico, but not necessarily in the same areas where the projects are implemented.

41. Lokey, E., "The status and future of methane destruction projects in Mexico," Renewable Energy 24 (2009), pp. 566-569.

42. Project 0463: "AWMS GHG Mitigation Project MX06-B-32, Aguascalientes and Guanajuato, México". http://cdm.unfccc.int/Projects/DB/TUEV-SUED1149779692.37/view

43. Lokey, E. (2009), op. cit.

44. GHG emission reductions from manure management systems. http://cdm.unfccc.int/methodologies/DB/M26OLGB-H210R9JGLGQEAH8XJ90WYB9/view.html.

45. "Greenhouse gas mitigation from improved Animal Waste Management Systems in confined animal feeding operations." http://cdm.unfccc.int/methodologies/DB/ATTQ-FAYJG4GS1ZV3PN2PNWFMZJQ70X/view.html.

46. http://cdm.unfccc.int/methodologies/DB/7AKWCSE6FKL3HO21F6BWN5E96SC8CU

47. In addition, the consolidated methodology introduced the use of the MCF, which is used to quantify the maximum methane generated by organic waste, based on values established by the Intergovernmental Panel on Climate Change (IPCC). Values will vary depending on the type of management system in place.

48. Enclosed flares are burners within a "cylindrical enclosure lined with refractory material." The flame in such flares is more uniform than in open flares. (Caine, M. "Biogas flares. State of the art and market review". IEA Bioenergy. December 2000. http://www.iea-biogas.net/Dokumente/Flaring_4-4.PDF.)

49. In cases where the flaring efficiency is monitored, actual data should be used.

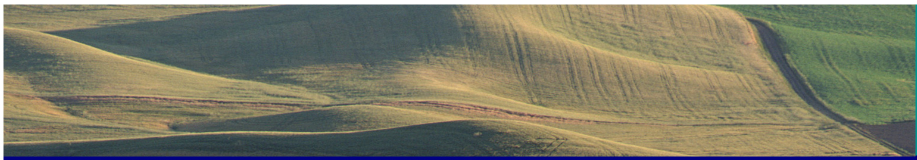
50. Approximately 20% of the projects in the CDM pipeline have decided to terminate validation. The majority of these projects are located in Mexico and list AgCert as the project developer.

51. U.S. EPA, December 2010, "Market opportunities for biogas recovery systems at U.S. livestock facilities," http://www.epa.gov/agstar/documents/biogas_recovery_systems_screenres.pdf .

52. U.S. EPA, June 2010, "Market opportunities for biogas recovery systems," http://www.epa.gov/agstar/documents/Market_Opps_Fact_Sheet.pdf .

53. http://www.epa.gov/agstar/index.html

54. http://www.epa.gov/agstar/tools/experts/index.html#state



55. http://www.epa.gov/agstar/documents/agstar_industry_directory.pdf

56. http://www.epa.gov/agstar/projects/index.html

57. "Road-Testing of Selected Offset Protocols and Standards – A Comparison of Offset Protocols: Landfills, Manure, and Afforestation/Reforestation," June 2009, Michael Lazarus, Gordon Smith (Stockholm Environment Institute (SEI)), and Kimberly Todd, Melissa Weitz (U.S. EPA Work Assignment Managers), Working Paper WP-U.S.0904, http://www.sei-us.org/WorkingPapers/WorkingPaperUS09-04.pdf.

58. Ibid.

59. Natsource estimate.

60. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st, 2011, http://cdmpipeline.org .

61. When the EB receives validation reports for a project seeking registration, it may automatically approve the report and register the project, or, if it has particular concerns about the project or the project type, it may call the project for review. In such cases, it may ask for clarifications to and revisions in the PDD, or it may point out more fundamental problems with the project. The project developer is given the opportunity to make the requested changes and seek registration again.

62. Institute for Global Environmental Strategies (IGES) Review and Rejected Project Database, January 2011. http://www.iges.or.jp/en/cdm/report_cdm.html.

63. For a more in-depth discussion of additionality, see *Overview of Different Approaches for Demonstrating Additionality of Greenhouse Gas Emissions Offset Projects*, Background Paper for the EPRI Greenhouse Gas Emissions Offset Policy Dialogue Workshop 2," September 2008, available online at: http://mydocs.epri.com/docs/PublicMeetingMaterials/0809/6CNS9RLUQLS/404416__E230717_Additionality_EPRI%20Workshop2_090208_Final.pdf. A more detailed summary of the CDM's additionality tests is provided in the Appendix to this paper.

64. Validation is the review by a DOE of a PDD's consistency with all CDM requirements. These include, but are not limited to, additionality, requirements in approved baseline and monitoring methodologies, and monitoring, verification and reporting requirements.

65. Verification is the review and ex-post determination by a DOE of the monitored emission reductions attributable to the project during the verification period.

66. The benchmark analysis compares the project's internal rate of return (IRR) or net present value (NPV) against a core business indicator. Benchmarks should be derived from government sources, estimates of financing costs and required return on capital, company internal benchmarks, or any other indicator justified by the project developer.

67 For example, assumptions in the PDD on the electricity tariff, the estimated amount of annual electricity generation, and the projected annual O&M costs.

68. "Information note: previous rulings related to the appropriateness of benchmarks for project activities utilizing waste heat/waste gas for power generation," http://cdm.unfccc.int/Reference/Notes/reg_note01.pdf.

69. Ibid., footnote 6.

70. Project 2780: Jidong Cement Panshi Co., Ltd. 15 MW Cement Waste heat Recovery Project, http://cdm.unfccc.int/Projects/DB/TUEV-SUED1248358466.68/view .

71. Project 2851: Jidong Cement Jilin Co., Ltd 6 MW Cement Waste Heat Recovery Project, http://cdm.unfccc.int/Projects/DB/TUEV-SUED1249329365.55/view.

72. EB fifty-second meeting report, http://cdm.unfccc.int/EB/052/eb52rep.pdf.

73. http://cdm.unfccc.int/Reference/Guidclarif/meth/meth_guid38.pdf .

74. http://www.epa.gov/chp/documents/ers_program_details.pdf.

75. U.S. EPA, March 2007, "Energy trends in selected manufacturing sectors: opportunities and challenges for environmentally preferable energy outcomes," http://www.epa.gov/sectors/pdf/energy/ch3-2.pdf.

76. http://www.epa.gov/chp/incentives/index.html.

77. Under the CDM, "afforestation" is defined as the direct human-induced conversion of land that has not been forested for a period of at least 50 years to forested land through planting, seeding and/or the human-induced promotion of natural seed sources. "Reforestation" is the direct human-induced conversion of non-forested land to forested land through planting, seeding and/or the human-induced promotion of natural seed sources, on land that was forested, but that has been converted to non-forested land. For the period 2008-2012, reforestation activities are limited to reforestation occurring on lands that did not contain forest on December 31, 1989. See FCCC/CP/2001/13/Add.1, as cited in Forests and Climate Change Working Paper 4, Choosing a forest definition for the Clean Development Mechanism, United Nations Food and Agricultural Organization (FAO), 2006, p.3.

78. For more information about the issues of permanence and leakage, please see the background paper and speaker presentations from EPRI's GHG Emissions Offsets Workshop #4 available online here: http://globalclimate.epri.com/annual_events__ghg_offset_policy_dialogue__archive.html#d20081120 .

79. A distinction is made between sequestration and storage of carbon. As noted in EPRI, 2006, "Removal of CO2 from the atmosphere (sequestration) can be a GHG emission offset. Keeping that carbon out of the atmosphere by storing the carbon in wood maintains the offset through time, but *does not create a new offset*." "Guidance for Electric Companies on the Use of Forest Carbon Sequestration Projects to Offset Greenhouse Gas Emissions," EPRI, Palo Alto, CA: 2006, 1012576, p. 5-2.

80. "Addressing Impermanence Risk and Liability in Agriculture, Land Use Change, and Forest Carbon Projects," Policy Brief, B.C. Murray and L.P. Olander, The Nicholas Institute for Environmental Policy Solutions, Duke University, October 2008, p. 2.

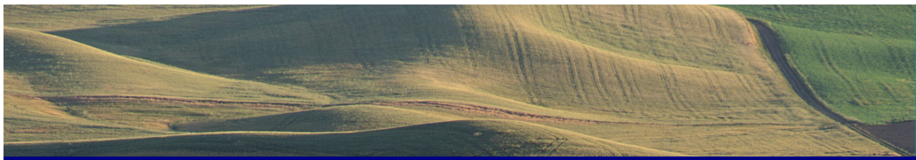
81. Ibid, p. 3.

82. Ibid.

83. Unless otherwise noted, information in this paragraph was derived from "Harnessing Farms and Forests in the Low-Carbon Economy: How to Create, Measure and Verify Greenhouse Gas Offsets," The Nicholas Institute for Environmental Policy Solutions, Zach Willey and Bill Chameides, Editors, Duke University Press, 2007, pp. 16, 20, 21, and "Permanence Discounting for Land-Based Carbon Sequestration," M-K Kim, B.A. McCarl, B.C. Murray, *Ecological Economics*, vol. 64, pp. 763-769, 2007.

84. "Guidance for Electric Companies on the Use of Forest Carbon Sequestration Projects to Offset Greenhouse Gas Emissions," EPRI, 2006, op. cit., p. 5-5.

85. Derivations of formulas for permanence discounts are provided in "Permanence, Leakage, Uncertainty and Additionality in GHG Projects," McCarl, B.A., in *Terrestrial GHG Quantification and Accounting*, Editor G.A. Smith, a book developed by Environmental Defense, 2006, pp. 24-32 of book chapter, and "Harnessing Farms and Forests in the Low-Carbon Economy: How to Create, Measure and Verify Greenhouse Gas Offsets," The Nicholas Institute for Environmental Policy Solutions, 2007, op. cit., pp. 125-127, and "Permanence Discounting for Land-Based Carbon Sequestration," M-K Kim, B.A. McCarl, B.C. Murray, 2007, op. cit., pp. 763-769.



86. "Addressing Impermanence Risk and Liability in Agriculture, Land Use Change, and Forest Carbon Projects," B.C. Murray and L.P. Olander, the Nicholas Institute for Environmental Policy Solutions, 2008, op. cit., p. 11.

87. "Guidance for Electric Companies on the Use of Forest Carbon Sequestration Projects to Offset Greenhouse Gas Emissions," EPRI, 2006, op. cit., p. 9-8.

88. Ibid, p. 3-6.

89. Personal correspondence with Gordon Smith, PhD, EcoFor.

90. The American Carbon Registry (ACR) is a non-profit voluntary registry founded in 1997 as the "GHG Registry" by two non-profit environmental organizations, the Environmental Resources Trust (ERT) and the Environmental Defense Fund (EDF). It was the first private voluntary GHG registry in the U.S. In 2007, ERT became part of Winrock International, another non-profit organization, and its registry was renamed the American Carbon Registry (ACR) in 2008. In that year, ACR was the most widely used voluntary carbon market registry in the world.

91. The Verified Carbon Standard (VCS) Program was known as the Voluntary Carbon Standard prior to March 1, 2011. The program aims to establish a rigorous, global standard for voluntary GHG emission reductions. The VCS 2007 (VCS' initial standard) was launched in November 2007 by the VCS Association (VCSA), a non-profit organization responsible for developing and maintaining the VCS Program. Three non-profit organizations created the VCSA – The Climate Group, the World Business Council for Sustainable Development (WBCSD), and the International Emissions Trading Association (IETA).

92. Information in this paragraph derived from "CDM Rulebook" entries for tCERs and lCERs, Baker & McKenzie, http://cdm-rulebook.org/PageId/332 .

93. A/R Project Design Document guidelines, p. 10, http://cdm.unfccc.int/Reference/Guidclarif/pdd/PDD_guid03.pdf

94. Provisions governing lCERs. Modalities and procedures for afforestation and reforestation project activities under the clean development mechanism, http://unfccc.int/resource/docs/2005/cmp1/eng/08a01.pdf#page=61.

95. Kyoto units are transacted between Parties to the Kyoto Protocol who have established national registries. These unites include Assigned Amount Units (AAUs), Removal Units (RMUs), Emission Reduction Units (ERUs), and Certified Emission Reductions (CERs).

96. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1, 2011, "A/R methods" worksheet, http://cdmpipeline.org/publications/CDMpipeline.xlsx.

97. See paragraph 31 of the A/R modalities and procedures, http://unfccc.int/resource/docs/2005/cmp1/eng/08a01.pdf#page=61.

98. "The BioCarbon Fund Experience: Insights from Afforestation/Reforestation (A/R) Clean Development Mechanism (CDM) Projects," January 2011, http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/BioCarbon_Fund_Experience_Insights_from_AR_CDM_Projects.pdf.

99. In the CDM context, modalities and procedures refer to the framework of rules pertaining to all CDM projects or, in this case, a particular sub-category of projects.

100. Simplified methodologies, which are designed to be less burdensome on project developers than standard methodologies, have been established for certain small-scale CDM project activities.

101. Ibid.

102 EPA Preliminary Analysis of the Waxman-Markey Discussion Draft – Appendix," EPA, April 20, 2009, p. 60 (offset graph), and "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," EPA, April 20, 2009, p. 18 (offset prices).

103. "A virtual "field test" of forest management carbon offset protocols: the influence of accounting," Galik et al., *Mitigation and Adaptation Strategies for Global Change*, DOI 10.1007/s11027-009-9190-9, 2009, http://www.nicholas.duke.edu/ccpp/ccpp_pdfs/offsets_mascg.pdf, Figure 4. Note that all breakeven carbon price estimates are approximate and based on a figure in the paper that did not display precise data points.

104. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st, 2011, http://cdmpipeline.org.

105. Annex 3, "Clarifications on the treatment of national and/or sectoral policies and regulations (paragraph 45 (e) of the CDM modalities and procedures) in determining a baseline scenario," http://cdm.unfccc.int/EB/016/eb16repan3.pdf.

106. Annex 32 "Information note on the implementation of E+/E- in the context of projects on the agenda of the fifty-third meeting of the CDM Executive Board," http://cdm.unfccc.int/Reference/Notes/reg_note06.pdf .

107. Based on a Natsource analysis of validation reports of a number of rejected projects.

108. China-Danish Wind Energy Development Program Office, "Study report on development of policy of Chinese wind power tariff," November 2009, http://cdm.ccchina.gov.cn/english .

109. The government-approved approach was used for regions without concession tenders or farms with a total installed capacity below 50 MW.

110. The experience gained through this approach led to a "government guiding tariff," where the tender mechanism is determined by the authorized government based on the criteria for a benchmark tariff. A detailed explanation of this process is not publicly available.

111. The NDRC is the government entity overseeing the implementation and development of national economic policies. The NDRC also houses China's Designated National Authority (DNA) for CDM and issues the letter of approval for CDM projects. (The DNA is the regulatory authority in a CDM "host" country that is responsible for providing a Letter of Approval (LoA) for a proposed CDM offsets project. It is charged with determining if a proposed offset project will contribute to "sustainable development" goals in the host country.)

112. The NDRC established four "wind resource regions," with the following tariffs: 0.51RMB/kWh, 0.54 RMB/kWh, 0.58RMB/kWh and 0.61 RMB/kWh. The basis for defining the wind resource regions is not explained in the document.

113. China-Danish Wind Energy Development Program Office, "Study report on development of policy of Chinese wind power tariff," November 2009, http://cdm.ccchina.gov.cn/english/, p. 5.

114. IETA "State of the CDM 2009."

115. With respect to Type E+/E- policies, the EB's fifty-fifth meeting report, paragraph 27 states: "The Board… agreed not to continue the consideration of the treatment of national and sectoral policies in the demonstration and assessment of additionality. The Board also agreed that possible impact of national and sectoral policies in the demonstration and assessment of additionality shall be assessed on a case by case basis," http://cdm.unfccc.int/filestorage/JTV1YA8FCHR4W2G-MEOQ53SK60P9DLX/eb55_rep.pdf?t=Z3d8MTI5ODU2NDkzNC4xNg==|gnMS7Qa68sxVLVPlj_5n2oySjKo= .

116. See "Information Note on the Highest Tariffs Applied by the Executive Board in its Decisions on Registration of Projects in the People's Republic of China," http://cdm.unfccc.int/Reference/Notes/reg_note07.pdf)

117. Response to request for review of UNFCCC Project 2774- "Heilongjiang Mudanjiang Xiaoguokui Wind Power Project," http://cdm.unfccc.int/filestorage/2NAOC3YPTXFEBS9J5GRQK1VZ4L7UWM/Joint%20response.pdf?t=dUF8MTI5Nzg5NDE1Mi43Nw==|uQgOPtu1o4nvaKIe1pLqnvZRKC0= .

118. The EB still requires projects to confirm additionality by showing the original investment test and a second test using the higher tariff.

119. http://cdm.unfccc.int/Projects/DB/BVQI1248250799.96/view.

120. IETA, "State of the CDM 2009," http://www.ieta.org/index.php?option=com_content&view=article&id=77:state-of-the-cdm-2009&catid=26:reports&Itemid=93 .

121. http://cdm.unfccc.int/methodologies/documentation/meth_booklet.pdf#AM0001.

122. World Bank, "State and Trends of the Carbon Market 2007," May 2007, p. 27, http://web.worldbank.org/WBSITE/EXTERNAL/NEWS/0,,contentMDK:21319781~pagePK:64257043~piPK:437376~theSitePK:4607,00.html .

123. Ibid.

124. World Bank, "State and Trends of the Carbon Market 2008, May 2008, p. 29, http://siteresources.worldbank.org/NEWS/Resources/State&Trendsformatted06May10pm.pdf .

125. World Bank, "State and Trends of the Carbon Market 2009, May 2009, p. 40, http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/State___Trends_of_the_Carbon_Market_2009-FINAL_26_May09.pdf .

126. World Bank, "State and Trends of the Carbon Market 2010," May 2010, p. 40, http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/State_and_Trends_of_the_Carbon_Market_2010_low_res.pdf .

127. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st 2011, "CDM Projects" worksheet, row 1354, http://cdmpipeline.org/publications/CDMpipeline.xlsx .

128. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st 2011, "Analysis" worksheet, Table 2 (calculated by author as 17% of estimated CER volumes by the end of 2012 for all CDM projects in the pipeline, rejected projects excluded) and Table 3 (calculated by author as 25% of estimated CER volumes by the end of 2012 for all CDM projects registered as of January 1, 2011), http://cdmpipeline.org/publications/CDMpipeline.xlsx.

129. Wara and Victor argue that "[p]ayments to refrigerant manufacturers, the Chinese government (which heavily taxes these CDM projects), and to carbon market investors by governments and compliance buyers will in the end total approximately €4.7 billion while estimated costs of abatement are likely less than €100 million." "A Realistic Policy on International Carbon Offsets," Michael W. Wara and David G. Victor, Working Paper #74, April 18, 2008, Program on Energy and Sustainable Development, Freeman Spogli Institute for International Studies, Stanford University, http://iis-db.stanford.edu/pubs/22157/WP74_final_final.pdf.

130. Kyoto Protocol, Article 12, http://unfccc.int/resource/docs/convkp/kpeng.pdf .

131. Wara and Victor, 2008, op. cit.

132. UNEP Risoe CDM/JI Pipeline Analysis and Database, January 1st, 2011, "Analysis" worksheet, Table 3 (taking into account estimated CER volumes by the end of 2012 for all CDM projects in the pipeline, rejected projects excluded), http://cdmpipeline.org/publications/CDMpipeline.xlsx .

133. Revision to approved baseline methodology AM0001 "Incineration of HFC23 waste streams" (version 03), http://cdm.unfccc.int/filestorage/AM0001_version3%20.pdf/AM0001_v.pdf?t=Mnd8MTI5NjI0NzM2MS4z|ffG2mH6fSKtDxSHI7XxVTbwZQ50= .

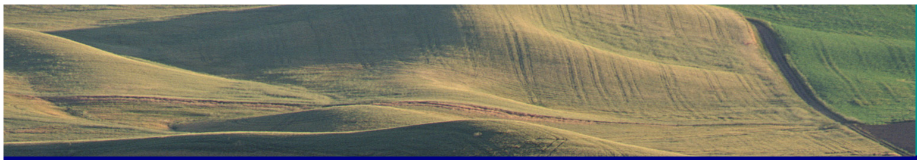
134. See glossary at the end of this report.

135. Decisions 8/CMP1, Implications of the establishment of new hydrofluorocarbon-22 (HCFC-22) facilities seeking to obtain certified emission reductions for the destruction of hydrofluorocarbon-23 (HFC-23), http://unfccc.int/resource/docs/2005/cmp1/eng/08a01.pdf#page=6 (p. 100) .

136. http://cdm.unfccc.int/methodologies/PAmethodologies/revisions/58215 .

137. CDM Watch Press Release, "UN under pressure to halt gaming and abuse of CDM," June 12, 2010, http://www.cdm-watch.org/wordpress/wp-content/uploads/2010/06/hfc-23_press-release_gaming-and-abuse-of-cdm1.pdf .

138. http://cdm.unfccc.int/Reference/Notes/meth_note02.pdf.



139. EB's sixty-fifth meeting report, p. 14, http://cdm.unfccc.int/filestorage/T/7/U/T7UE2AMI6SY4OBHQ3KN08VXJWL-5D1C/eb65_report.pdf?t=Yk58bHZlMDU2fDCEsojAF6VcfwIH-LKs2PSZ .

140. http://europa.eu/rapid/pressReleasesAction.do?reference=IP/11/56.

141. Point Carbon, "Australia to ban HFC 23, N2O CERs from carbon scheme, July 11, 2011, http://www.pointcarbon.com/news/1.1557892 (subscription required).

142. Radio New Zealand News, "Two greenhouse gases may be excluded from ETS," October 1, 2011, http://www.radionz.co.nz/news/political/87025/two-greenhouse-gases-may-be-excluded-from-ets .

143. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2009," EPA 430-R-11-005, April 15, 2011, http://epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 4-60 .

144. Ibid.

145. Ibid.

146. Ibid.

147. http://www.gpo.gov/fdsys/pkg/BILLS-111hr2454eh/pdf/BILLS-111hr2454eh.pdf . This bill also is referred to as the "Waxman-Markey bill." The House of Representatives passed this legislation in June 2009.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

EPRI Resources

Adam Diamant, *Senior Project Manager, Global Climate Change, Electric Power Research Institute (EPRI)*
510.260.9105, adiamant@epri.com

1023671 December 2011

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com