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CARBON TRADING PROTOCOLS FOR GEOLOGIC SEQUESTRATION

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INTRODUCTION

Carbon capture and storage (CCS) could become an instrumental part of a future carbon trading system in the United States. If the U.S. starts operating an emissions trading scheme (ETS) similar to that of the European Union's then limits on CO_2 emissions will be conservative in the beginning stages. The government will most likely start by distributing most credits for free; these free credits are called allowances. The U.S. may follow the model of the EU ETS, which during the first five-year phase distributed 95 % of the credits for free, bringing that level down to 90% for the second five-year phase. As the number of free allowances declines, companies will be forced to purchase an increasing number of credits at government auction, or else obtain them from companies selling surplus credits. In addition to reducing the number of credits allocated for free, with each subsequent trading period the number of overall credits released into the market will decline in an effort to gradually reduce overall emissions. Companies may face financial difficulty as the value of credits continues to rise due to the reduction of the number of credits available in the market each trading period. Governments operating emissions trading systems face the challenge of achieving CO_2 emissions targets without placing such a financial burden on their companies that the country's economy is markedly affected.

To create market flexibility and thereby ease some of the economic hardship created by emissions trading, existing trading systems in the E.U. and Norway have devised ways to achieve the target emissions reduction without forcing companies to buy credits covering all of their emissions. One option companies have is to secure credits called offsets. To receive an offset a company can reduce CO_2 emissions of an operation not covered by the cap and trade system; this means reducing emissions abroad or reducing the emissions of a small operation not answerable to the nation's ETS. In this way, the company is still reducing CO_2 emissions, but it is a less expensive alternative to reducing emissions created by their own operations.

There are several different classifications for offset projects defined by the Clean Development Mechanism (CDM) of the Kyoto Accords. Projects are characterized in the following categories: biological sequestration, industrial gases, methane capture, energy-efficiency, and renewable energy projects (Kollmus et. al, 2008). Not all of these project types are equally effective, and each must undergo rigorous examination to determine whether the project merits the assignment of an offset credit. Although offsets are a valuable option in an ETS, in the EU and in Norway limits have been placed on the number of offsets a company can earn in order to encourage the company to make the more expensive, real reduction in CO_2 emissions from their own installations. Norway, for example, only allows 20% of a companies total carbon credits to be offset credits. After a company has attained a maximum allowable number of offsets, it then needs to seek out additional ways to reduce emissions, and CCS projects could provide additional CO_2 reduction. Because of the similarity between offset projects and CCS projects, protocols pertaining to CCS projects could ultimately be derived from the existing framework that assesses the effectiveness of existing offset projects.

Although CCS technology is expensive at present, as an ETS progresses buying credits on the market will eventually become too costly, at which point CCS projects will become a viable option for companies trying to stay in operation. The credits that will be awarded for CCS projects are called Emission Reduction Credits (ERCs). ERCs are credits granted to a company for voluntarily reducing emissions below the required level. ERCs can thus be used against future emissions in the quantity specified by the ERC. Because credits can be banked during each five-year trading period, ERCs are valuable assets that can be saved, accumulated, and traded.

There is the potential for widespread use of CCS technology under an upcoming emissions trading system, but because this technology is still being developed and is not yet cost effective, it has not been used in any of the trading systems currently in existence. Steps are just now beginning to be taken to integrate a set of protocols for CCS into the existing carbon trading protocols in the E.U., Norway, and Australia. Despite these preliminary steps, there is still much work that needs to be done in organizing a framework for permitting CCS sites and for granting ERCs to completed projects. The following paper will propose ways in which these two developments might be addressed.

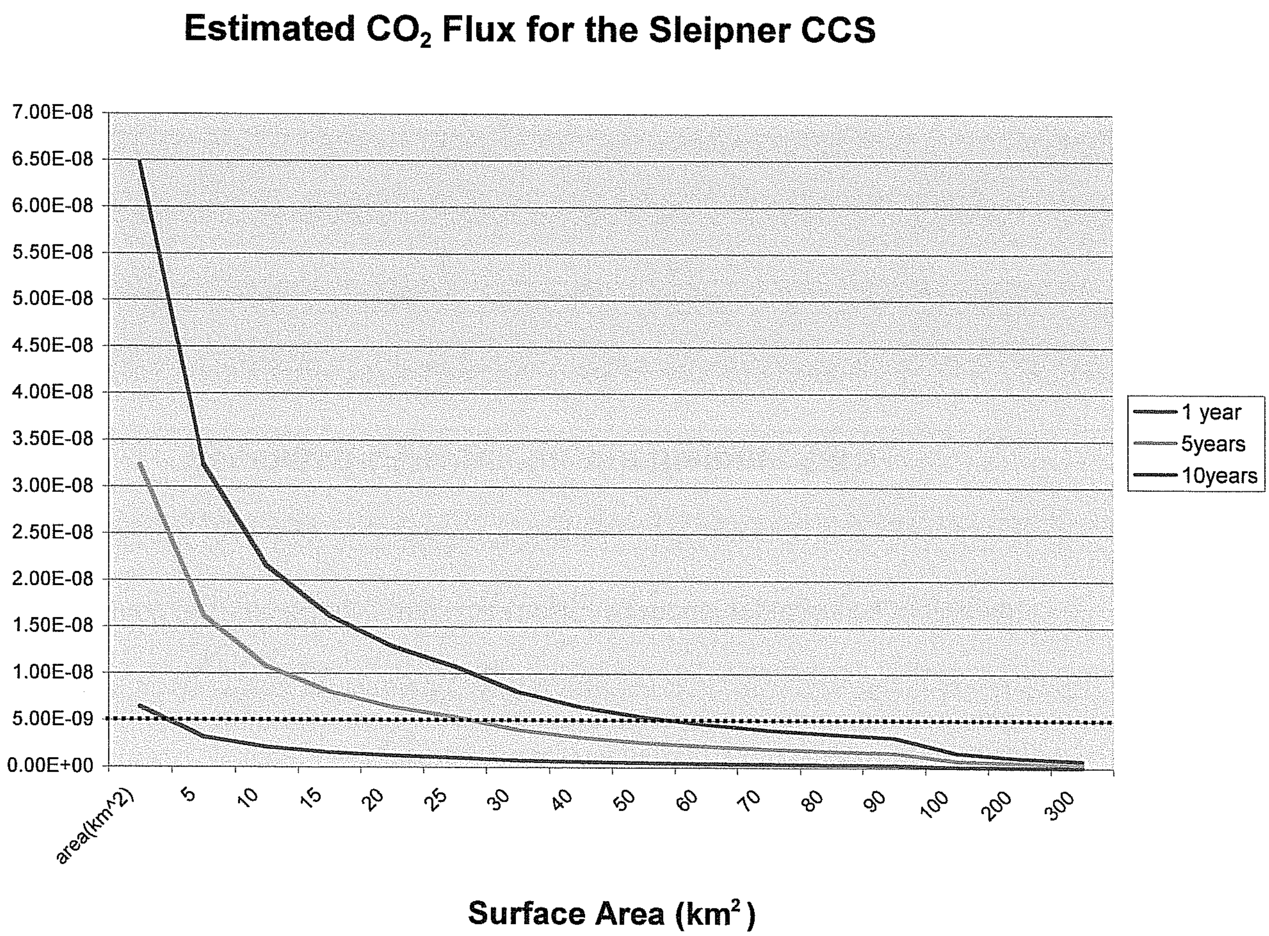
GUIDELINES FOR CCS PROJECTS TO BE PERMITTED

Before it is possible to set in place a system for allocating ERC's to companies who employ CCS technologies to reduce their GHG emissions, it is necessary to establish benchmarks defining a successful CCS project. The most basic requirement of a CCS project is that it poses no danger to public health and safety, nor can it cause damage to surrounding ecosystems. Assuming the safety of the project has been successfully demonstrated in the characterization phase, the net step is to determine how long the CO_2 must remain contained underground in order for the project to be effective in the long-term reduction of atmospheric GHG levels. Estimates indicate that if 60 to 95% of the CO_2 remained underground for approximately 500 years the sequestration effort would be viable (Rubin et. al, 2005). In order to reach this 500 year mark, the leakage rate from the storage site should not exceed 0.1% a year. With a leakage rate as great as 1% a year, as has sometimes been considered acceptable, most of the CO_2 would return to the atmosphere in just 400 years (Hepple et. al, 2003). With the acceptable leakage rate established at 0.1% a year we have set an important standard in assessing the success of a CCS project that will help us determine whether the company undertaking the project will be granted the desired ERCs.

In establishing a maximum permissible leakage rate another important consideration is whether routine Monitoring, Measurement and Verification (MMV) techniques will be able to detect leakage levels of the specified magnitude. One concern is that small scale CCS projects may inject such a small amount of CO_2 that any leakage from such a site could not be monitored. However, studies (Oldenburg et. al, 2003) demonstrate that the Eddy Covariance (EC) technique has the capability to measure a CO_2 flux as small as 4.4×10^{-9} $kgm^{-2}s^{-1}$. Other techniques such as the Accumulation Chamber (AC) method can measure a similar flux magnitude. Because conditions can vary widely between sites, the figures from Oldenburg et. al, 2003 may not always be achievable. Therefore, for most projects several MMV techniques with different capabilities will be used. Despite this, we will use this figure for CO_2 flux to make several assumptions about the level of leakage that may be detectable.

Figure 1, based on the Statoil's CCS demonstration project at Sleipner, provides an estimation of how much CO_2 flux would be present over varying surface areas after several different time periods. At Sleipner 2,800 metric tons of CO_2 are injected each day, resulting in the sequestration of 1.02 million metric tons each year. Assuming that 0.1% of the sequestered CO_2 leaks each year, and neglecting the effects of transit time from the CO_2 bearing formation to the surface, the CO_2 flux at the surface has been calculated as a function of the surface area over which the CO_2 reaches the atmosphere. In practice the travel time for the CO_2 to transit the subsurface would need to be added to the time shown in the figure. Small surface areas, on the order of five to ten kilometers, would represent CO_2 leaking from a single fault system (e.g. 5 km = 1 km in extent). CO_2 being dispersed in the subsurface and reaching the surface over a broad area might leak from a 100 km^2 area. The flux rates shown in figure 1 can be scaled by the volume of CO_2 in place. It can be assumed that a commercial scale project would inject at least ten times this volume of CO_2 each day, thus the illustrated model represents a very small CCS project.

Figure 1:



In Figure 1 the horizontal black dashed line illustrates the flux level detectable using the EC technique. CO_2 leaking from a single fault zone with a 5 km^2 area would be detectable after only one year's accumulation, after five years any area less that 25 km^2 would produce detectable levels. After ten years of injection leakage could be detected even if it were dispersed over as much as 50 km^2. This model indicates that MMV techniques will be adequate in detecting the specified leakage rate for most commercial projects, which typically will be at least ten times the volumes illustrated in Figure 1, before a company has relinquished liability for the site.

An extensive site permitting process for CCS projects will provide the infrastructure for ensuring that the above stated goals will be met with all possible certainty. The U.S. Environmental Protection Agency (EPA) has already proposed certain regulations, applying their experience with regulating the underground injection of other potentially hazardous materials. Currently, Enhanced Oil Recovery projects and several geologic sequestration pilot projects are classified according to the existing regulations for sequestration of hazardous waste, which has five well classifications for permitting purposes. Table 1 summarizes the existing five well classifications, including features such as: injected fluids, construction, injection depth, design, and operating techniques.

Table 1: Existing Well Classifications (EPA, 2008)

Class I Wells	Inject non-hazardous liquid, municipal wastewaters or hazardous wastes beneath the lowermost USDW. Most often they are the deepest UIC wells.
Class II Wells	Inject fluids from conventional oil or natural gas production, enhanced oil and gas production, and liquid hydrocarbons.
Class III Wells	Inject fluids associated with the extraction of minerals or energy.
Class IV Wells	Inject hazardous or radioactive wastes into or above USDWs. Very few of these are in use today.
Class V Wells	All injected wells that are not included in the other four classes. Class V wells are generally experimental technology wells, and today include geologic sequestration pilot projects.

As the practice of geologic sequestration of CO_2 proliferates under a carbon trading system the need for a new classification will arise. The EPA has proposed the creation of a sixth classification to specifically address the new challenges geologic sequestration presents (EPA, 2008).

The creation of a new classification establishes the task of designing a permitting process specific to geologic sequestration. In consideration of the peculiarities of each CCS site, the EPA proposes what they call a "Tailored Requirements Approach" to permitting. This includes previously established technical standards for deep-well injection of non-hazardous fluids where appropriate and later adapting them in consideration of the challenges of long-term CO_2 storage. This gives permitting authorities the flexibility to alter certain provisions of the recommended protocols in order to either heighten security when needed or to relax burdensome standards in cases when they are unnecessary.

AN AUSTRALIAN EXAMPLE

The EPA has also made strides in identifying many of the responsibilities delegated to the owners or operators of a CCS project once injection has begun, however a final system may be able to draw from a proposed Australian framework. The Offshore Petroleum Amendment Bill (Australian Office of General Counsel, 2008) created an Australian legal framework for granting permits to CCS projects. By combining aspects of the Australian bill with the proposals by the U.S. EPA a comprehensive permitting system could be realized in the U.S.

The first permit granted in the Australian system is the GHG assessment permit. This allows the permit holder to perform four "key greenhouse gas operations, including: drilling a well, injecting small quantities of GHGs for site appraisal, conducting seismic surveys, and monitoring the behavior of the stored GHG. The GHG assessment permit stays in effect for six years.

After the owners and operators have proved that their site is an Identified GHG Storage Formation, they can begin the process of applying for an Injection License. To attain the characterization of an Identified GHG Storage Formation the permit holder must submit a battery of information, including: their reason's for believing that the site is suitable for permanent storage, the quantity of GHG suitable to store, the particular GHG that will be stored, the proposed injection points, the proposed injection period, the proposed engineering enhancements, the sealing feature, and the spatial extent of the storage formation including the expected migration pathways. After the permitting authority has reviewed these submissions and declared the site in question to be an Identified GHG Storage Formation, there as several other elements that must be taken into consideration. An "impacts test" must be performed to determine whether granting the injection license for this particular site would be in the public interest. Next it must be proved that the owners and operators have the technical and financial resources to complete the project in accordance with regulatory procedures. Finally, the owners and operators must be in the position to start injection within five years of receiving the license.

If the owners and operators are not in the position to begin injection within five years of their site classification as an Identified GHG Storage Formation, then they may apply for a GHG Holding Lease. This lease will remain in effect for five years, and may be renewed once. This gives the owner and operators rights to the site for a period of years during which they may obtain enough GHGs for injection. When they are eventually ready to inject the GHGs they can easily apply for an Injection License.

THE U.S. EPA PROPOSAL

These Australian regulations provide a solid process that can be used to grant drilling and injection rights to applicants, however, the EPA proposal has a more comprehensive set of demands for owners and operators once the injection process has begun. Owners or operators of Class VI wells must report semi-annually to the permitting authority on: the physical and chemical nature of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, annulus fluid volume added, the results of mechanical integrity testing, plume tracking, and atmospheric and soil gas monitoring

(EPA, 2008). In addition, plans of the Area of Review (AoR), referred to by the Australian requirements as the demand that owners or operators submit an estimation of the spatial extent of the storage formation and the expected migration pathways, play an integral role in the regular monitoring of the injection site. AoRs indicate the importance of extending the survey of the underground formations beyond simply the expected storage site so as to ensure that the GHGs do not travel to other areas unexpectedly (EPA, 2008).

The EPA strongly believes that AoRs should be conducted regularly as part of routine MMV procedures. Although they have not been able to determine an absolute requirement for the frequency with which AoRs should be conducted, the EPA has resolved that at no time should the AoR reevaluations occur less often than every 10 years (EPA, 2008). Along with these AoRs the owners and operators must submit a corrective plan in the event of an unexpected migration (EPA, 2008).

Another strength of the EPA proposal is the definition of the site care period between the end of injection and the attainment of a site closure certificate. The length of this period is still debated; many environmental programs find 30 years adequate, however the storage of CO_2 creates different concerns, which will likely require a longer period. To determine the length of this period for CCS projects the EPA proposes a combination of a fixed timeframe and a performance standard based approach. Studies done by Flett, M., Gurton R., and G. Weir. 2007; Obi E.I., and M.J. Blunt. 2006; and Doughty, C.2007 indicate that the CO_2 plume could stabilize anywhere within a 10 to 100 year time frame, and site specifics play a large role in determining this outcome. To account for this the EPA plans to set 50 years as a flexible site care period that may be adjusted at the authority's discretion if owners or operators have demonstrated that the CO_2 plume has stabilized (EPA, 2008).

After the site care period has ended the owners or operators may apply for a site closure certification that allows the licensee to surrender his title. In order to receive this certification the owners or operators must submit a site closure report and a non-endangerment demonstration showing that conditions in the subsurface indicate no additional monitoring is needed (EPA, 2008). However, before the owner or operator can abandon the site completely, for three years following site closure they must continue to basic MMV record keeping and reporting.

In the United States there is currently no authority in place that has the rights to oversee all of the elements of the CCS permitting and crediting processes. Under the Safe Drinking Water Act (SDWA) the EPA has a clear title to ensuring the protection of USDWs (Underground Source of Drinking Water); this entitles the EPA to regulate the injection of CO_2 underground. The EPA acknowledges however, that "the SDWA does not provide authority to develop regulations for all areas related to GS (geologic sequestration)" (EPA, 2008). In order to create a comprehensive and streamlined permitting and crediting system, the EPA, or some other governing body, will need the authority to regulate injection, the site assessment process, property rights, and the certification of GHG reductions. The EPA indicates that the Clean Air Act may provide enough latitude for them to claim rights in regulating more of the CCS process, however to achieve the fully integrated permitting and crediting process that has been suggested it is necessary that the Congress pass legislation that gives the EPA, or some other body, a clear and complete title to regulating all CCS operations and crediting.

PROPOSED ERC PROTOCOLS FOR U.S. CCS PROJECTS

The proposed protocols combine the current EPA proposals with the structure that the Australian protocols provide. What remains missing is the piece concerning the ERCs, which I propose to incorporate into the permitting framework. Although carbon offset projects designated under the CDM do not have permitting processes that are directly relevant to permitting for CCS, the system of integrating the permitting process with the achievement of offset credits has been a success. The most important considerations in assigning ERCs to a CCS project will now be addressed, along with an explanation of how they fit in to the CCS permitting framework.

A well-defined and comprehensive permitting process specific to CCS projects will allow ERCs to be assigned with relative ease. The permitting process will help to identify whether the company sequestering the CO_2 is appropriately addressing the specific standards deemed necessary to qualify the company for receiving ERCs. Mandatory requirements for receiving an ERC have been derived from the standards applied to offset credits. These requirements are as follows: the stored CO_2 must be real, surplus, quantifiable, unique, and verifiable. Key elements of the proposed protocols are summarized in Table 2.

Table 2: Key Elements of the Proposed CCS Crediting Protocol

Feature	Explanation
GHG Assessment Period	A key part of the permitting process, this determines if the site is safe and desirable for a CCS project.
Determination of Project's Eligibility to Receive ERC's	It must be determined that the stored CO_2 is real, surplus, quantifiable, unique and verifiable.
Method of Payment for ERC's	ERCs are put into an Escrow fund and paid out over a three-year period. If leakage rates above the acceptable level occur then a proportion of the awarded credits must be paid back and the project owner must pay an additional fine.
Penalty for Leakage	For a leakage over 0.1% some proportion of the ERCs paid to the owner must be returned for each year the leakage continues. In addition the owner will be subject to a fine upon discovery of the leakage.
Site Monitoring Obligations	Extensive MMV over the injection period must take place. Following the end of the injection there is a fifty-year (subject to adjustment) site care period with an AoR survey done a minimum of every ten years.
Liability for the Site	The permit holder retains liability for the site until the site closure certificate is granted from which point on the government must claim liability for the site. The permit holder alone is entitled to receive ERC credits from the permitting authority.
EOR Projects	EOR projects may be considered additional if the CO2 used

	has been captured during industrial processes. ERCs will also be assigned based on the degree to which the produced oil is "carbon free". EOR projects wishing to be credited will be under Well Classification VI.

To be "real" stored CO_2 must create an actual reduction in the emissions of the company; as such there cannot be leakages from the storage site that compromise the act of injecting the CO_2 in the first place. Within the protocols for granting ERCs the issue of "real" reductions must specifically be addressed to ensure that leakage occurring after the assignment of the ERC result in both a payback proportional to the amount leaked and a punitive damage component. Although this issue has yet to be addressed, existing permitting procedures do provide for the stringent monitoring of leakage, in both its pre-injection surveys of the site and in its provisions for regulations post-injection.

The next condition, that injected CO_2 must be "surplus", refers to the necessity that the amount of CO_2 sequestered be in excess of the companies reduction obligations in order to receive the ERC. The need to verify a surplus is also commonly referred to as setting a baseline, and is addressed comprehensively in the CDM qualifications for offset credits. The Kyoto Protocol considers an offset project viable only if the offset emission comes from a project that would not have occurred in the absence of the possible credit; that is, the project must have additionality. Establishing the additionality of a project is not addressed by the Australian or U.S. EPA proposals because it is unique to the subject of crediting. This condition can be easily incorporated into the permitting process by following the CDM model. Operators of CDM offset projects are required to submit a Project Design Document, which must include estimations of the project baseline and justifications for those approximations. The Project Design Document could be adapted for CCS projects and a provision could be added to applying for and Injection License requiring it. CDM offset projects also require rigorous verification after the project is underway to ensure that the baseline was properly estimated, and that the operator did not exaggerate the net reductions of the project. This will be a necessary part of regulating CCS projects; along with the regular MMV reports, there needs to be provisions for verification by a third party that the project's claimed reductions are indeed real.

To be "quantifiable" the sequestered CO_2 must create a readily discernable net reduction. The CO_2 that is actually stored, that is excluding fugitive emissions at the time of capture, transport, and injection, must be easily accounted for so that the proper amount of ERCs can be granted. This provision has been adequately provided for by the permitting protocols, in their detailed design for routine MMV, which will be able to ascertain the quantity of CO_2 sequestered with enough accuracy to assign the ERCs.

A geologic sequestration project is "unique" if the company desiring to do the sequestration holds a clear title to the site where the sequestration is to occur and thus is the rightful owner of the ERCs that are to be distributed for the project. Additionally, the ERCs themselves, granted on behalf of the project must be unique; therefore there must be a strict serialization and registration process in place to ensure against double counting. Careful accounting for ERCs must be integrated into MMV routines following the start of injection.

Regarding the issue of the site title-holder, this condition is preliminarily addressed by the permitting process, whose underlying purpose is to grant the title of temporary ownership of the storage site. Despite this, terms of the Australian permitting process may need to be clarified to address the different claims of the company wishing to sequester its CO_2 and the third party company hired to operate the site. A provision should be invoked stating that all ERCs for a given CCS project will only be issued to the party in possession of the Injection License, thus the owner of the site should be the company wishing to attain the ERCs. The owner then subcontracts the company operating the injection. The operator has no claim to ownership of the site and will receive none of the ERCs granted for the project; instead the operator will be paid directly by the owner. There is however some latitude in adjusting this arrangement, for example the owner and the operator may wish to negotiate a different system of payment. One possibility would be to make an agreement that affords the operator the right to a certain percentage of the ERCs obtained from the project in lieu of a service fee. While this agreement is perfectly viable, this is still a contract between the owner of the site and the operator, and it is not the responsibility of the crediting authorities to pay the ERCs directly to the operator. Instead it is duty of the owner, who will receive all the ERCs from the permitting authorities, to transfer the appropriate number of ERCs to the operator.

Finally the sequestered CO_2 must be "verifiable", that is, a third party must track its movements or leakages. Each step of the permitting process, from the GHG assessment permit to the site-closing certificate, strives to ascertain that the behaviors of the stored GHGs are routinely measured and monitored. The EPA has outlined specific requirements for the types of MMV techniques and the extent to which MMV is employed in detail. This ensures that all third party verifiers will perform to the same high standard and thus gives credibility to the verification process.

The proposed seamless integration of these five ERC qualifications into the permitting system, will allow for a streamlined process of allotting ERCs to the owners of geologic sequestration projects. The achievement of all five must be verified before the injection license can be granted, as such, the distribution of credits should be able to commence at the time of injection. Figure 2 illustrates a timeline of the permitting process integrated with the ERC achievement period.

Figure 2: Timeline Illustrating Example CCS Project

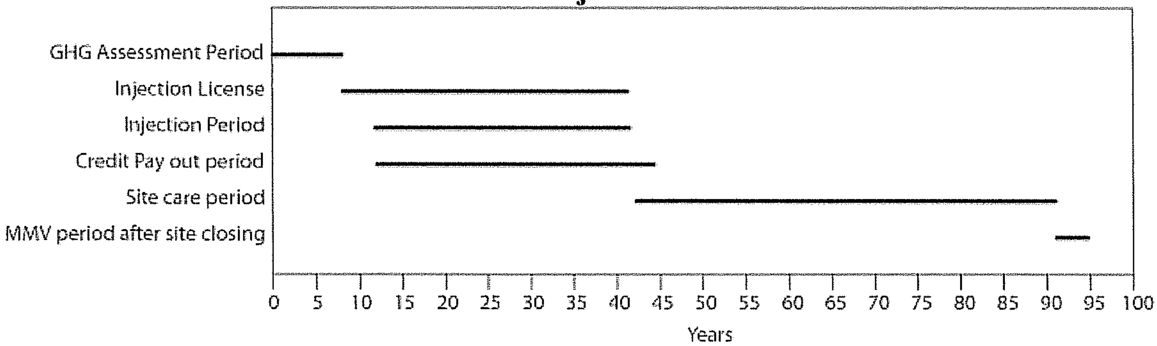


Figure 2 shows a timeline for an example CCS project. For this example, the duration of each phase of the project has been estimated at its maximum number of years.

Injection of enough CO_2 to fill the storage site may take as many as thirty years to complete. With such an extended period, we must address how the ERCs are to be granted for the GHGs sequestered over this timeframe. One approach is to place the ERCs into an Escrow fund whose pay out period is set at some fraction of the total predicted injection time. For example, for a project with a thirty year expected injection time, the pay out period could be on a three year interval. With a three year pay-out, at the end of the first year of injection one third of the ERCs applicable to that year's tons of injected CO_2e would be given to the owner. For the subsequent two years the remaining thirds would be paid out. Because injection takes place over an extended time period, the owner would receive payments for up to three different years at a time. For two years after the end of injection the company would be receiving that last of its ERC payments.

Payment of the ERCs begins immediately under the condition that MMV reports show that there are no unexpected leakages or problems surfacing that are unaddressed by the site plan. Payment will continue according to the pay out schedule assuming that the leakage rate from the storage site remains under 0.1% a year. If leakage rate rises above that threshold the project will be considered ineffective in achieving a goal of long-term atmospheric GHG reductions, and thus the project owners will suffer several penalties. At the discovery of the leakage all future ERC payments will be held. The owner will also be subjected to an immediate penalty, in the form of a fine. Additionally, the owner will be forced to surrender a proportion of his ERCs each year the leakage continues. The owner is required to make an attempt at repairing the leakage. If this is accomplished, that is the leakage is reduced to below the 0.1% a year threshold, the owner no longer must surrender ERCs. The owner is then free the next year to begin collecting ERCs again for the tons of CO_2e stored, however more stringent monitoring standards will be applied to the site.

If the owner is not able to repair the leakage he will continue to pay back the set proportion of ERCs each year. The owner still retains liability for the site, and must continue to submit the same MMV reports each year. If the site is deemed safe and stable over a period of years then the owner will still be able to apply for a site closing certification, and can then eventually relinquish liability for the site.

ASSIGNMENT OF ERCs FOR ENHANCED OIL RECOVERY PROJECTS

Enhanced Oil Recovery (EOR) projects present a unique situation for the proposed permitting and crediting process. The first question regarding EOR that must be addressed, is whether EOR projects meet all of the standards that qualify a CCS project for receiving ERCs. Using the Kyoto definition of additionality, EOR projects currently in operation do not merit the compensation of ERCs (de Coninck, 3). Kyoto outlines several tests for project additionality; simply put, the goal of these tests is to discern whether or not the project would be been undertaken in the absence of receiving an ERC. If the test determines that the project would indeed have occurred regardless of the ERC, then the project is not additional. The Investment Test is applicable to EOR, stating that the revenue from the credits received on behalf of the project must be the decisive reason for implementing the project (Kollmus et. al, 2008). Based on this test, current EOR projects do not pass because revenue from the oil attained is the primary motivation for the project.

Although Kyoto tests for additionality provide sound reasons why current EOR projects should not receive ERCs, the U.S. Department of Energy (DOE) has posed examples of EOR projects that could meet the standards of additionality. For these future projects CCS protocol must address how ERCs will be assigned. This proposed protocol dictates that under no circumstances can an EOR project receive ERCs for re-injecting CO_2 unless the CO_2 used in the project has been acquired from an emission source. If the CO_2 is instead obtained from geologic formations then the goal of the emission reduction is entirely compromised since no net reduction in atmospheric CO_2 levels is achieved. The project owners will then receive ERCs for the CO_2 that is separated from the recovered oil and re-injected into the well. In this case the Investment Test does not apply, because the cost of capturing the CO_2 at the emission source exceeds the cost of getting the CO_2 from underground, thus awarding ERCs to an EOR project provides the incentive to reduce overall emissions.

The second component of the ERC granting process must address the degree to which the oil produced is "carbon free". The DOE asserts that the oil produced by EOR projects is up to 70% "carbon free", in comparison to imported oil that is 0% "carbon free", and domestic corn ethanol that is only 10 to 15% "carbon free". The DOE estimates that a typical barrel of crude oil contains 0.42 metric tons of releasable CO_2, whereas a barrel of crude oil obtained through EOR could contain as little as 0.26 metric tons (Kuuskraa et. al, 2008). Calculations could be done for the total number of barrels produced by the EOR project to determine how many metric tons of releasable CO_2 were avoided, and based on that number additional ERCs could be assigned.

Permitting and well classification are the greatest problems in granting ERCs for EOR projects. Current EOR projects are included under the U.S. EPA's second well classification, while commercial CCS projects are to be placed in a sixth well classification. Because the crediting process is unique to and dependent on the permitting framework of Well Class VI, it is altogether necessary that EOR projects aiming to achieve ERCs are fit into this classification. EOR projects not aiming to achieve credits may remain in the second classification so that they do not face unnecessary burdens. Credited EOR projects in Class VI will face more stringent requirements however there is enough flexibility in the crediting system to account for site specific needs that this will not be cumbersome to project owners.

Ownership of the ERCs granted is more complicated for an EOR project than for a typical CCS project. The oil company, as the permit holder, has exclusive rights to the ERCs. They are responsible to negotiate a method of payment with the emission source they receive the CO_2 from. If the oil company agrees to pay the emission source with ERCs this exchange is a private agreement between the two companies with no involvement from the permitting authority.

JUSTIFICATION FOR PROPOSED PROTOCOL

There are certainly other systems one could create for paying out ERCs to the owner of the stored CO_2, however, there are several reasons why delivering them in an Escrow type format is preferable. The suggested system provides a reminder to the owners that the full payout of ERCs is contingent upon their adherence to the strict standards governing the stored CO_2. Paying out ERCs over a period of three years rather than up front helps ensure that the CO_2 storage is a long-term investment.

The time frame chosen for the payout time is very important. If the time frame is too long, CCS projects may become less desirable to companies who need to acquire ERCs for the short term. For the substantial cost that is required to operate a CCS project there must be some form of pay off that companies can receive almost immediately for the project to remain lucrative. The suggested three-year time frame may need to be adjusted, but the ultimate timetable decided upon should realistically not be extended beyond ten years. Experience in offset trading supports this point; the Chicago Climate Exchange, North America's first voluntary GHG emissions trading system, does not extend the crediting period of any offset project beyond the duration of 8 years (Kollmus et. al, 2008). In determining the optimum crediting period for CCS projects, one potentially critical factor is the estimated time from the point of injection that it will take to detect impending leakages with MMV techniques. If the timeframe for this is site specific then it is possible that the length of the pay out time frame could vary slightly between sites.

The suggested system is straightforward and can be applied universally without many differences between sites, which is preferable to the more complicated systems, such as the Canadian offset crediting system. To summarize, the Canadians propose creating two different types of offset credits, permanent credits (PC) and temporary credits (TC), with different property rights associated with each. PCs and TCs differ in both the liability associated with each, and the value of the credit and the owner of the project can choose which type of credit to apply for (Thomassin, 2006). Although this system provides a greater degree of flexibility, the more uniform proposed system prevents confusion in the issuance of ERCs, alleviating a good deal of administrative complexity. Additionally, a system that is easy for the company owners to understand makes it more probable that they will want to engage in a CCS project.

CONCLUSION

These proposed protocols for assigning ERCs to geologic carbon sequestration projects offer much room for adjustment and change. The final permitting and crediting system for CCS projects cannot be decided until a national carbon trading system has been initiated in the United States. By looking at the progress made by other countries to establish protocols specific to CCS, this proposal has identified several key components that should be addressed in the U.S. system.

Above all it is important that a more comprehensive permitting process is put in place to ensure that CCS projects are only initiated after extensive assessments of the safety and viability of the site. The entire permitting process must also be integrated with the crediting process in order to increase efficiency and streamline record keeping. A detailed regimen for monitoring and verification must be established to ensure the safety of the site and to address any leakages that may affect the receipt of ERCs. There have been many proposed methods for awarding credits over the injection period. Although the proposed method of issuing them may need to be adjusted, it is important that owners of CCS projects are held responsible to return the ERCs if they do not meet the terms of the agreement at some point while they retain liability for the site. One of the complications in devising protocols governing CCS projects is uniqueness of each site. Over time a balance will have to be achieved to allow a certain degree of flexibility for site specific decisions while still preserving a framework rigid enough to ensure safe operation and fair delegation of ERCs.

APPENDIX I

AoR: Area of Review

CDM: Clean Development Mechanism

CCS: Carbon Capture and Storage

CO_2e: Carbon Dioxide Equivalent

EC: Eddy Covariance

EOR: Enhanced Oil Recovery

EPA: Environmental Protection Agency

ERC: Emission Reduction Credit

EU ETS: European Union Emissions Trading System

GHG: Green House Gas

GS: Geologic Sequestration

MMV: Measurement, Monitoring, and Verification

SDWA: Safe Drinking Water Act

UIC: Underground Injection Control

USDW: Underground Source of Drinking Water

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