Carbon market readiness

Accounting, compliance, reporting and tax considerations under state and national carbon emissions programs

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Introduction

Given the recent legislative efforts around healthcare, financial reform and economic stabilization, United States (US) lawmakers did not finalize the proposed climate legislation in 2009. However, it is anticipated that new climate change legislation will be enacted as soon as 2010. Notwithstanding the anticipated enactment of any new climate change laws in 2010, the Environmental Protection Agency (EPA) now requires Greenhouse Gas (GHG) emissions to be reported effective 1 January 2010 for certain facilities and companies.

In this publication, we explore some of the accounting, compliance/reporting and tax considerations with respect to the existing carbon emissions programs in the US and highlight the opportunities and challenges that companies should consider as they each develop a carbon market readiness plan in anticipation of future regulatory and legislative changes. Ernst & Young is committed to working with our clients as these regulatory and legislative changes unfold. For further information and assistance, please contact any of the individuals listed under "Contacts" in this publication.

Current landscape

Carbon emission reporting and reduction programs have expanded rapidly in recent years at the state, regional, national and international levels. Many countries around the globe have already implemented some type of cap-and-trade program aimed at reducing carbon emissions, and US lawmakers are now seriously discussing the possibility of implementing a cap-and-trade program that could take effect in the next few years.

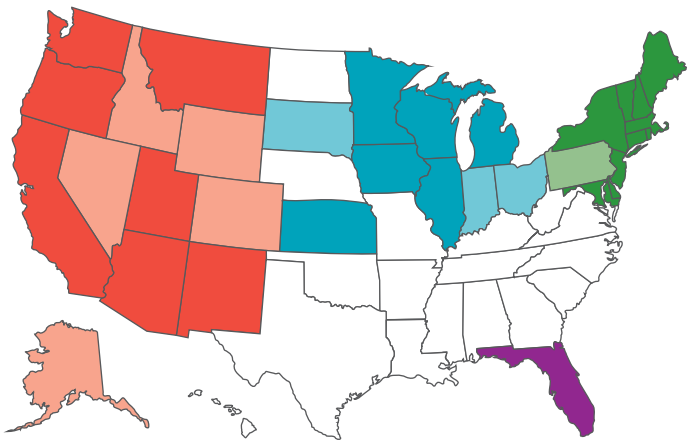
Under a typical cap-and-trade program, participants are allocated emissions credits that represent allowable amounts of carbon emissions. These credits can also be traded. To the extent that an entity emits more emissions than the allowed limits (corresponding to the permits held), it must buy permits from the market or pay a penalty.

These emissions credits are typically bought and sold among emitting and non-emitting counterparties. At the end of the compliance period, participants are typically required to deliver emissions credits equal to their actual emissions, and they may be required to pay a fine or suffer other penalties for emissions in excess of their credits. In addition, there are typically quarterly and/or annual reporting requirements mandating that the emissions be quantified and reported to the federal agency responsible for overseeing the cap-and-trade program.

Under various state, regional and national regulatory requirements, many companies that currently emit GHG, such as power generators and utilities, have been provided or have had to acquire emissions credits to cover certain carbon emissions (primarily sulfur dioxide and nitrous oxide). However, there is no current accounting standard in US generally accepted accounting principles (US GAAP) that addresses the accounting for carbon emissions programs.

The following map illustrates the different programs in place in the US:

Regional carbon management programs



- Regional Greenhouse Gas Initiative RGGI
- RGGI Observer
- Midwestern Regional GHG Reduction Accord
- MRGHGRA Observer
- Western Climate Initiative
- Western Climate Initiative Observer
- Individual State Cap-and-Trade Program

Carbon emissions programs that currently mandate the use of cap-and-trade and/or emissions reporting include:

Regional Greenhouse Gas Initiative (RGGI) – RGGI is the first mandatory, market-based effort in the US to reduce greenhouse gas emissions. RGGI only addresses carbon dioxide emissions and only applies to electric power producers. States sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy and other clean energy technologies. RGGI's stated goal is to spur innovation in the clean energy economy and create green jobs in each state.

Jurisdictions: Northeast US (Connecticut, Delaware, Massachusetts, Maryland, Maine, New Jersey, New Hampshire, New York, Rhode Island and Vermont) – mandatory for power plants. In addition, observers include: the District of Columbia, Pennsylvania, Quebec, Ontario and New Brunswick.

Timeline: Mandatory monitoring, measurement and reporting, along with a mandatory cap-and-trade program, began on 1 January 2009.

Western Climate Initiative (WCI) – WCI is an aggregation of US states and Canadian provinces that have agreed on a common cap-and-trade scheme. WCI is similar to RGGI but somewhat behind it in terms of its development. WCI goals are to (1) set regional emissions reduction goals, (2) develop a registry to track and manage emissions reductions and offset credits and (3) design a multi-jurisdictional-based cap-and-trade system. When fully implemented in 2015, WCI will cover nearly 90% of greenhouse gas emissions in WCI partner states and provinces, including those from electricity, industry, transportation, and residential and commercial fuel use.

Jurisdictions: Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Ontario, Oregon, Quebec, Utah and Washington. Observers included the US (Alaska, Colorado, Idaho, Kansas, Nevada and Wyoming), Canada (Saskatchewan and Nova Scotia) and Mexico (Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora and Tamaulipas).

Timeline: Mandatory measurement, monitoring and reporting for GHGs will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011. The cap-and-trade program commences on 1 January 2012.

Midwest Regional GHG Reduction Accord – Six US states and one Canadian province have agreed to establish regional GHG targets, including a long-term target of 60% to 80% below current emissions levels, and develop a multi-sector cap-and-trade system to help meet targets.

Jurisdictions: Kansas, Minnesota, Iowa, Illinois, Wisconsin, Michigan and Manitoba. Observers: South Dakota, Ohio, Indiana and Ontario.

Timeline: Mandatory measurement, monitoring and reporting for GHGs will commence in January 2010 for all entities and facilities subject to reporting. Reporting of 2010 emissions will begin in early 2011. The cap-and-trade program commences on 1 January 2012.

Environmental Protection Agency (EPA) – To address air quality and pollutant concerns, the Clean Air Act (CAA) of 1990 provides broad authority to the EPA to implement and enforce regulations reducing air pollutant emissions. The legislation placed significant limitation on the emission of Sulfur Dioxide (SO2) and Nitrous Oxide (NOx) by electric power plants and established a cap-and-trade system for these pollutants. Under the SO2 and NOx program, power-producing companies are allocated NOx and SO2 emissions credits that either can be held for future use to cover actual emissions or can be sold or traded. In addition, the CAA has stiff monetary penalties for plants that release more pollutants than are covered by their allowances.

It is important to note that the CAA granted broad authority to the EPA to regulate all air-polluting emissions in the US. The Supreme Court recently ruled that GHG emissions are air pollutants as described in the CAA, so the EPA must regulate them.[1] Accordingly, the EPA in its final rule (published in September 2009) requires mandatory reporting of GHG emissions from large sources in the US. The rule is very prescriptive in the manner in which GHG emissions are to be calculated. The EPA has estimated that 10,000 facilities will be subject to the rule, and an additional 17,000 facilities will need to evaluate if they are subject to the new reporting requirement. Facilities primarily affected by the rule include those with specified processes (such as stationary fuel combustion or electricity generation) that may have carbon dioxide equivalent (CO2e) GHG emissions greater than 25,000 metric tons per year.

Jurisdictions: The US.

Timeline: For facilities currently reporting air emissions data quarterly, their first report is due 31 March 2010. For other facilities, reports are due 31 March 2011 for 2010 emissions. Vehicle manufacturers start reporting later.

California's Regulation For the Mandatory Reporting of Greenhouse Gas Emissions – Regulations stipulating the mandatory reporting of greenhouse gas emissions in California are currently in effect. In general, the rules pertain to the following types of California-based operations: (1) cement plant operators; (2) operators of petroleum refineries, hydrogen plants or stationary combustion systems in California that emit greater than or equal to 25,000 metric tonnes of CO2;(3) operators of cogeneration facilities that are located in California that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO2 (4) operators of California-based electricity generating facilities that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO2; and (5) electrical energy retailers and suppliers as defined in California regulation.

Jurisdictions: Facilities as identified above that are located in California. Electrical power marketers and retailers supplying California from non-California based operations may also have reporting requirements.

Timeline: All identified facilities must report and have third-party verification of the 2009 emissions in 2010. In general, the deadline for emissions reporting is 1 June for petroleum refineries and cement plants, and 1 April for all other operations subject to the rule. The rule also requires verification of emissions by accredited third-party verification bodies. The deadline for securing verification is six months following the deadline for reporting.

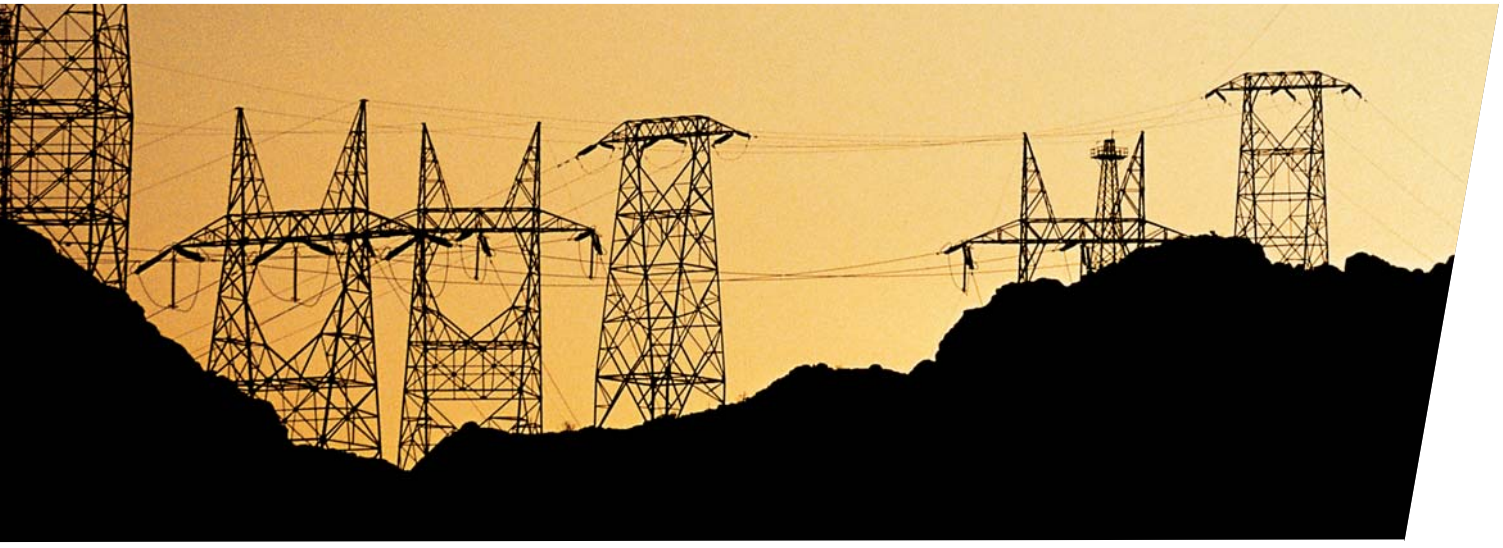
[1] *Massachusetts, et al, v, Environmental Protection Agency (EPA)*, 549 U.S. 497; 127 S. Ct. 1438; the Court analyzed Section 202(a)(1) of the Clean Air Act, 42 U.S.C. §7521(a)(1) indicating that the EPA is required to set emission standards for "any air pollutant…which in his judgment cause(s), or contribute(s) to, air pollution which may reasonably be anticipated to endanger public health or welfare."

The Clean Air Act (CAA) established a cap-and-trade system for SO2 and NOx emissions of electric power producers. Under that system, the electric power producers were allotted (free) or they acquired emissions credits to cover their SO2 and NOx emissions. Even though this program has been active since 1995, there is still no current accounting standard in US GAAP that addresses the financial accounting for emissions programs. The US SO2 and NOx trading program applies principally to electric utilities, and it appears that diversity in practice exists with respect to the accounting and financial reporting in this industry. At the present time, the Financial Accounting Standards Board (FASB) is working on a joint project with the International Accounting Standards Board (IASB) to address the accounting for carbon emissions schemes.

The Internal Revenue Service (IRS) provided guidance to taxpayers in 1992 that deals specifically with the SO2 and NOx cap-and-trade program established as part of the CAA[2]. This guidance however was limited to the allocation of those allowances by the EPA and related tax accounting. The guidance does not address the tax treatment of GHG emission trading programs discussed above or those proposed in Congress. It is interesting to note that the pending legislation in Congress, at present, is silent as to the income tax treatment of the respective cap-and-trade programs[3].

Notwithstanding the final outcome of the various US legislative efforts, certain companies that emit GHGs may be impacted by expanding state, regional and federal carbon emission reporting programs (such as the September 2009 EPA GHG emission reporting rules) must now, or in the near future, begin reporting GHG emissions. As such, companies will need to ensure that they have appropriate protocols in place for capturing, measuring, and reporting GHG emissions pursuant to these programs. Where applicable, these companies will also need to account for the related cap-and-trade activities associated with the program without specific authoritative accounting guidance. Furthermore, many companies may be required to disclose the impact of climate change and the regulation of GHG emissions in their Annual Report on Form 10-K.

As a result of the carbon emissions programs that are currently in place and the proposed cap-and-trade regulations being debated by Congress, it is critical that companies have a carbon management strategy that enables them to not only comply and account for these activities but also allows them to be positioned to take advantage of acquiring credits and offsets through strategic acquisitions or otherwise.



2 Revenue Procedure 92-91, 1992-2 C.B. 503; Revenue Ruling 92-16, 1992-1 C.B. 15; this guidance generally provided that the allocation by the EPA (for free) of the SO2 and NOx allowances were not included in gross income of the recipient. They also provided guidance on the subsequent acquisition of allowances and the related cost recovery. It is important to note that this guidance is specifically limited to the SO2 and NOx program established in the CAA.
3 The Senate Finance Committee conducted a public hearing on 16 June 2009 to discuss the federal income tax implications of cap-and-trade legislation. The Staff of the Joint Committee on Taxation issued a brief report on the income tax consideration in advance of that hearing on 12 June 2009 that summarized many of the tax considerations associated with a carbon cap-and-trade system.

Current accounting practices

Certain companies in the US, mostly those in the power and utilities industry are currently required to participate in the EPA, RGGI and other carbon emissions programs and have been for several years. Some of these programs have a cap-and-trade model. At present, there is no accounting standard or interpretation within US GAAP or International Financial Reporting Standards (IFRS) that specifically addresses the accounting for emissions credits, renewable energy certificates, emissions offsets or similar allowances. As a result, varying practices have emerged for the accounting for emissions credits and related products.

With the onset of a potentially broader-based carbon emissions program in the US, the accounting for cap-and-trade programs and related products will likely affect a broad set of companies in industries such as oil and natural gas production, transportation, storage, refining and manufacturing. Because of the broad implications, the need for an accounting standard that provides a framework for climate change accounting that can be applied consistently across all industries has been elevated. Both the FASB and the IASB recognize this need and, to that end, added a joint project to their agenda in December 2007 on accounting for emissions trading schemes. An exposure draft is expected to be issued in the first half of 2010, with a final standard expected in 2011.

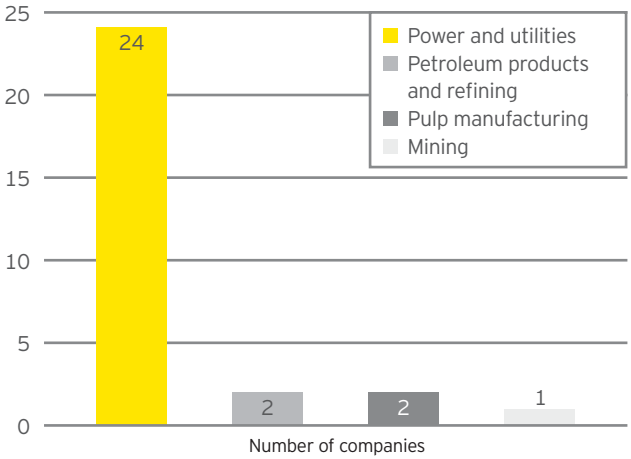
Current accounting for emissions credits or allowances

In a survey of US public registrants with revenues between $1 billion and $100 billion for annual filings occurring between 1 February 2009 and 13 September 2009, we noted that 29 companies disclosed an accounting policy related to emissions credits or allowances in the notes to their financial statements.

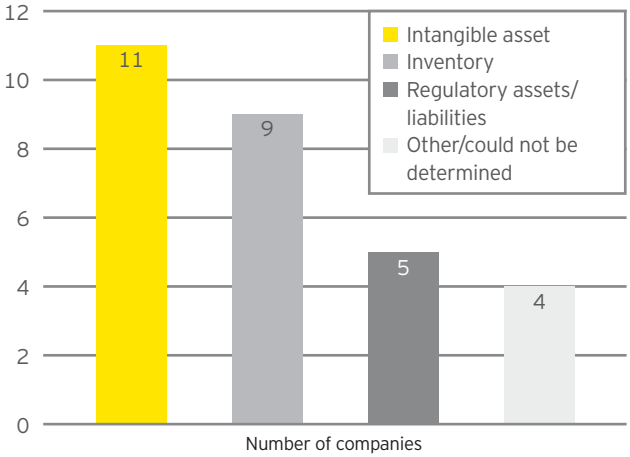
Of the 29 companies, the following chart summarizes the methods of accounting used for emissions credits or allowances:

Companies with an accounting policy addressing emissions credits or allowances

By industry sector



Methods of accounting for emissions credits or allowances



As depicted in the chart above, companies that apply US GAAP and participate in today's carbon emission programs generally follow one of two different accounting practices: an intangible asset model or an inventory model.

Accounting under the intangible asset model

Under the intangible asset accounting model, companies generally initially measure emissions credits or allowances issued to them and acquired in the open market at cost. Therefore, to the extent a company is issued emissions credits or allowances, the company has only a nominal or zero cost. Conversely, emissions credits or allowances purchased would have a cost associated with them. However, while not a commonly applied practice, under the intangible asset accounting model, it also is possible for an entity to reflect even issued emissions credits or allowances at their fair value when received. Based on the disclosures provided, companies generally do not amortize the emissions credits, because their economic benefit is not diminished until they are consumed. As such, the costs of the credits are not charged to expense until they are sold or used. The emissions credits or allowances are subject to impairment under the indefinite lived intangible asset impairment model or the fixed asset impairment model for finite intangible assets, to the extent a company is amortizing the emissions credits. The emissions credits are classified as long-term in the balance sheet, and the cash inflows and outflows related to the emissions credits are classified as investing activities in the statement of cash flows. In addition, companies provide the required disclosures in FASB Topic 350, *Intangibles*.

Accounting under the inventory model

Under the inventory accounting model, emissions credits are generally measured at a weighted-average cost. Emissions credits issued by the EPA or other regulatory body typically have a zero cost basis, while purchased emissions credits are recorded at their purchase price. The weighted-average cost of emissions credits used each period is charged to fuel costs (or cost of sales). The emissions credits are subject to the lower of cost or market approach to impairment under the inventory model. The emissions credits are classified as inventory in the balance sheet, and the cash inflows and outflows related to the emissions credits are classified as operating activities in the statement of cash flows.

Companies that trade emissions credits generally follow the inventory model. However, if a company that trades emissions credits is within the scope of the industry guidance for broker/dealers, they generally account for emissions credits held for sale at fair value at each reporting date.

Liability and gain recognition

Under both models, industry practice is that the entity generally does not record an obligation to deliver emissions credits to the regulatory agency until the actual level of emissions for a given period exceeds the credits held on the balance sheet. Furthermore, a gain is typically recognized in the period in which the emissions credits are sold (for example, if the company holds excess credits and sells those credits to other market participants). We note, however, that practice varies with regard to gain recognition in that some companies have adopted an accounting policy that requires the deferral of the gain if the emissions credits were granted for a future vintage year but are sold in the current year. In this case, the gain may not be considered realizable because the company may be unable to cover its emissions in the future vintage year due to its sale of emissions credits that were granted for the purpose of covering future vintage year emissions.

Vintage year swaps

In certain existing US cap-and-trade programs, each individual emissions credit or allowance has a vintage year designation that is indicative of the first year an allowance may be used. Unused allowances may be carried forward to future years. Allowances with the same vintage year designation are exchangeable and may be remitted by any party to cover its emissions from any source. Vintage year swaps are common because government agencies typically issue allowances for multiple years at a time. For example, an entity may expect to install equipment to reduce its emissions in 2009 but may need additional allowances in 2008 to cover a projected shortfall. That entity might exchange some of its allowances with a 2010 vintage year designation (when it expects to have reduced emissions) for allowances with a 2008 designation. One of the significant differences between the intangible asset and inventory accounting models is with respect to the accounting for vintage year swaps. Under the inventory method, a vintage year swap would be accounted for at carryover basis based on inventory exchange guidance. However, under the intangible asset model a vintage year swap would be accounted for on a fair value basis, assuming commercial substance.

Derivative accounting

It is a very common business practice for companies to enter into forward contracts, swaps and/or options pertaining to emissions credits. In most instances these arrangements, depending on their specific terms, will generally meet the definition of a derivative under US GAAP. Certain forward contracts that culminate in physical delivery where net settlement does not occur, may be eligible for the normal purchases/normal sales exemption, but other products that settle financially are generally required to be accounted for at fair value. As these markets continue to evolve and expand, we expect more and more contracts to meet the definition of a derivative.

Standard-setting activities

After FASB Statement No. 153, *Exchanges of Nonmonetary Assets* (codified in Topic 845, *Nonmonetary Transactions*), was issued in December 2004, questions arose in practice as to whether vintage year swaps should be accounted for at fair value because the nonmonetary transaction guidance would generally result in fair value accounting if the emissions credits were accounted for as inventory. As a result, in 2006 the FASB added a project to its agenda to address the nature of emission allowances and clarify the accounting for vintage year swaps. The initial proposed recommendation made by the FASB staff in addressing this point was that emission allowances are not inventory. However, this project was never finalized, and the FASB never concluded on the accounting model.

One of the primary issues in accounting for emissions credits or allowances is how an issued credit, allowance or offset should be initially measured and whether an initial measurement of zero is appropriate. The FASB staff acknowledged that the guidance contained in the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts is the only accounting guidance available in the US that explicitly addresses emissions allowances. Based on the research it has performed, the FASB staff has stated that most US entities generally account for emission allowances in a manner similar to that required by FERC regulations. The FERC requires entities to recognize emission allowances on a historical cost basis and to expense them as "consumed" on a weighted-average cost basis. As such, whether the emissions allowances are accounted for under an intangible asset or inventory model, practice generally demonstrates that no value is assigned to emissions allowances that are granted to companies. The Emerging Issues Task Force (EITF) took on a project in 2003 to establish accounting guidance addressing participants' accounting for emissions allowances under a cap-and-trade program. The proposed guidance (EITF Issue No. 03-14) was based on the same accounting model as the FERC requirements and would have required emissions allowances to be classified as inventory. However, the EITF did not reach a consensus and removed the issue from its agenda.

In 2004, the International Accounting Standards Board (IASB) addressed the accounting for emissions credits and allowances in International Financial Reporting Interpretations Committee (IFRIC) and issued IFRIC 3, *Emissions Rights* (IFRIC 3). IFRIC 3 required emissions credits and allowances to be classified as intangible assets and initially measured at fair value, regardless of whether the credit or allowance was allocated by a regulatory body or purchased. However, IFRIC 3 met with significant resistance on the basis that it resulted in accounting mismatches between the measurement of assets and liabilities. This mismatch occurred because under IFRIC 3 the emissions credits received would be recognized when obtained (generally, at the beginning of the year), whereas the associated emissions liability would be recognized as it is incurred (that is, throughout the year). Consequently, the IASB decided to withdraw IFRIC 3 in 2005. Under IFRS, companies generally develop an accounting policy based on International Accounting Standard (IAS) 8, *Accounting Policies, Changes in Accounting Estimates and Errors*.[4]

4 Please refer to our Ernst & Young Global publication, *Accounting for emission reductions and other incentive schemes* (EYG No. AU0347),for a more in-depth discussion of our accounting insight as it relates to the different accounting practices under IFRS.

Looking ahead

As previously discussed, the FASB expects to issue an exposure draft in the first half of 2010 that addresses the accounting for emissions trading programs. To this end, the FASB has been working closely with the IASB to develop an accounting model under US GAAP that is consistent with the accounting model being developed by the IASB. At the 8 April 2009 FASB meeting, the FASB staff presented recommendations for the initial measurement of issued credits or allowances (offsets) to the FASB and IASB members. The FASB staff presented two alternatives for the initial measurement of issued offsets: cost (nominal amount) or fair value. In evaluating the cost alternative, the FASB noted that there are certain circumstances in US GAAP where non reciprocal transfers are measured at a nominal amount. In addition, the FERC requires issued offsets to be accounted for at cost in the regulatory financial statements. However, the FASB staff noted that initial measurement at cost raises concerns about gain recognition on subsequent sales of issued offsets and the potential for companies to manage earnings. In addition, current accounting literature generally requires that assets received in non reciprocal transfers are required to be measured at fair value, other than in certain specific circumstances. Through its research, the FASB staff indicated that users polled expressed that they would prefer fair value measurement because it would provide more transparent and useful information. Therefore, the FASB staff recommended that the issued offsets be initially measured at fair value.

In its recommendation, the FASB staff recognized that initial measurement of fair value of the assets raised questions about the accounting for the credit. This credit could be recognized as a gain, other comprehensive income or a liability. The FASB staff presented three models with respect to accounting for the credit if issued offsets are measured at fair value: non reciprocal transfer model, performance obligation model and the compensation model. The non reciprocal transfer model would generally result in gain recognition, and the performance obligation model would result in recognition of a liability upon initial measurement. The compensation model is focused on the concept that the issuance of offsets is intended to compensate for the change in value of certain assets. As a result, the credit would be recorded to PP&E or another balance sheet account. The FASB staff recommended the performance obligation model because the staff did not believe initial gain recognition was appropriate, and believed the performance obligation model best reflected the substance of the arrangement.

While the FASB Board discussed the FASB staff's recommendations, no decisions were reached at the meeting, and the FASB staff was instructed to perform more research about the existence of a liability in various situations and will present its analysis at a future meeting. The Board members generally agreed that gain recognition at initial measurement did not seem appropriate; however, some Board members did not agree that a present obligation exists that warrants recognition of a liability.

At the 18 November 2009 joint meeting with the IASB and FASB (the Boards), the IASB staff prepared a staff paper on the accounting for items in a voluntary program. The IASB staff focused on a voluntary program because it believes that by entering a voluntary program, members make a legally binding commitment intended to reduce their emissions compared to the level of historic emissions. The discussion focused primarily on whether the definitions of an asset and liability had been met for a voluntary program under the FASB Concept Statements and IASB Framework. The IASB staff presented two views on whether the definition of a liability had been met. View 1 is that an entity's actual emissions are the obligating event in a voluntary program and there is no present obligation until an entity has emitted. View 2 is that entering into the membership contract is the event that creates a liability (the obligating event). By signing the membership contract, the entity's obligation to pay allowances is unconditional. Many members of Boards indicated that the program should be viewed overall as a whole as opposed to looking at individual assets and liabilities. Additionally, some Board members did not believe there should be a distinction between voluntary and mandatory programs. Although the IASB staff did not ask for a decision to be reached, the IASB and FASB Board members indicated a preference toward View 2.

We expect the Boards to continue to discuss accounting models for both voluntary and statutory programs in the first quarter of 2010.

Some of the accounting issues that may be addressed in the next phase of the project include, but are not limited to:

- Subsequent accounting (including impairment)
- Accounting for emissions obligations
- Accounting for vintage year swaps
- Disclosures

In terms of potential transition alternatives, it is too soon to speculate what method will be chosen by the FASB. However, due to the current diversity in practice and the trend in retroactive transition requirements for new accounting guidance, we believe that companies may be required to apply any new guidance on the accounting for emissions credits or allowances retroactively. As new information becomes available, we will provide publications to summarize the status of the FASB/IASB project to address the accounting for emission trading programs.

Compliance and reporting considerations

Compliance is the most important element of any mandated GHG program. Companies will need to develop processes and controls to measure, monitor and report GHG emissions. To avoid fines and penalties, companies will also need to develop processes and controls to enable them to accurately report the required information to the US EPA. The US will likely administer GHG and climate change both through new congressional legislation as well as under the existing CAA. The new US EPA mandatory GHG reporting rule announced 22 September 2009 is under the authority of the CAA and will affect approximately 10,000 facilities which are now required to report their GHG emissions for calendar year 2010. Also, on 30 September 2009 the US EPA proposed a new rule requiring operating permits for GHG emissions under the CAA. The proposed rule would limit GHG emissions from nearly 70% of the US's largest stationary source GHG emitters, including power plants and refineries. Other federal agencies may also be involved in regulating GHG emissions, further complicating the compliance efforts. In addition to the GHG emission reports that companies will have to submit to federal agencies, companies may be required to furnish additional information about GHG emissions levels in their public filings with the Securities and Exchange Commission (SEC) (e.g., Item 1. Business) if the future costs associated with compliance are material.

For many companies (particularly US companies with power generation assets), near real-time compliance procedures are already in place to monitor the federally regulated program for emissions (SO2 and NOx). Those existing processes and procedures may be scalable such that adaption of existing compliance controls to GHG emissions (other than SO2 and NOx) may require only incremental effort. For most companies, however, the inclusion of GHG in the emission portfolio may tax a compliance process that is already marginally effective at producing auditable results. Furthermore, sites or companies that are new to emissions monitoring will require an initial implementation of these processes and procedures.

Chapter 8 of the US Federal Sentencing Guidelines encourages a robust compliance management system. For the new GHG reporting rules, this will mean that written compliance procedures, adequate resources and appropriate training for key personnel involved in the data collection and reporting processes are in place. Additionally, internal compliance audit of the GHG data collection and reporting processes and processes for periodic reporting to top management regarding compliance status and GHG reporting program results should be in place. This is especially important as the new GHG reporting rule requires companies to self-certify their emissions to the EPA.

The US EPA has asked for a 34% budget increase over last year, the largest in the EPA's history, to enable them to be more active in regulating and enforcing GHG rules and has requested $600 million for its Enforcement and Compliance Assurance Program, including 30 new positions for its civil/criminal enforcement program that will be active in enforcing GHG rules among other regulations. Additionally, the American Reinvestment and Recovery Act (ARRA) provides the EPA Office of Inspector General with $20 million for oversight activities available through 30 September 2012 to inspect the US EPA's operations. As a result, we can expect more robust environmental regulation and enforcement in the next few years.

The three key steps in a robust compliance program are measurement, monitoring, and reporting as outlined below.

Measurement
The first step in the compliance process is measurement. While real-time measurement and feedback is the ideal that most companies aspire to achieve, it is not necessarily the only approach. Measurement at the plant level on a frequent basis, most likely in accordance with production, serves as the foundation for the compliance system. The frequency will depend on the needs of the monitoring function; however, it is important that there be controls in place to ensure accurate and timely reporting of emission information. In most cases, these controls will be facilitated through a technology-assisted measurement solution, which either will automatically measure GHG emissions using measurement equipment at the source of the emissions, or will estimate based on the quantity of production. In cases where the emissions data is collected using a manual calculation process (typically based on meter readings), the strength and depth of the control environment becomes more important. In either case, specific controls to regularly test or prove meters or measurement devices, as well as reconciliation controls to match emissions with actual production, are necessary.

Monitoring
Production and emission information is typically passed to a separate monitoring function within the organization. The monitoring function can take many different forms in the energy industry. In some cases, information is provided to a plant-level environmental or compliance officer. In other cases, the monitoring function may be a centralized group within the company, such as a trading floor that will actively manage and trade around the emissions position.

Regardless of the structure, controls over the accuracy and completeness of the information during hand-off must be maintained, or the company will risk non compliance. While manual processes can be implemented to control the accuracy of data, technology-enabled solutions are the most reliable means of transferring information from one group to another.

Once emissions information is received by the monitoring function, the information must be transformed into information that can be used to manage the GHG emissions during the reporting period. Analytic tools to compare such details as "actual emissions versus available credits" or "budgeted emissions against actual emissions" are key drivers of the monitoring and management process. As it is for other emissions, the measurement period for GHG is expected to be quarterly or annual depending on type of emission. As such, other analytic tools that may provide trend analysis and forecast future emissions are important to ensure proper management of emissions allowances early in the reporting period.

Frequency of the monitoring process throughout the measurement period is also important. Proactive approaches to monitoring "emissions versus allowances" are necessary for dynamic companies that do not have a stable, budgeted and ratable production process throughout the measurement period. These companies, such as merchant electric generators, will adjust production to market demand. External factors such as weather and unexpected operational constraints will impact the quantity of emissions against forecast early in the measurement period.

Reporting
Despite the importance of the monitoring process, reporting for GHG emissions will be the area with the largest impact to companies (even those with previously established emissions reporting processes). The reporting requirements for GHG will be distinct from other emissions reporting.

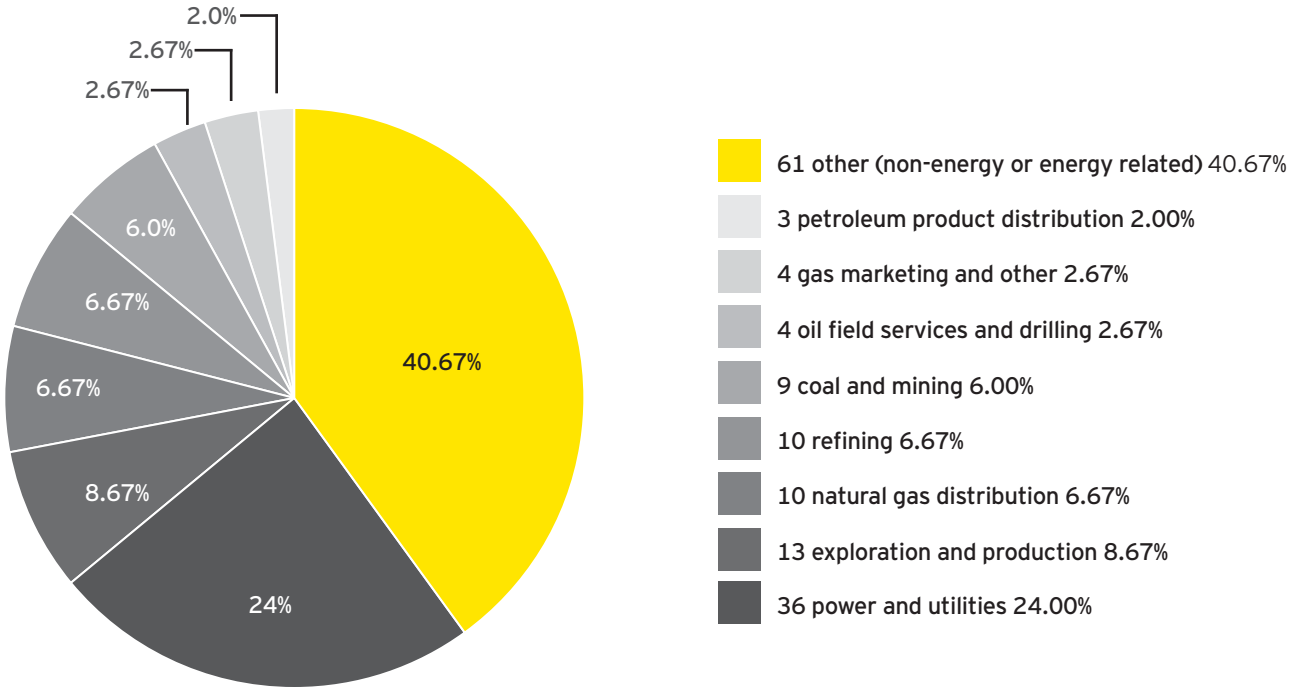
There are two key components to reporting for GHG emissions: regulatory reporting and public disclosure. Like other emissions, regulatory reporting will be a major part of compliance. However, GHG reporting will be in addition to the existing reports and could be significantly different in regard to format and types of information that is required in the report.

Public disclosure of climate change information will be a new area for most US companies. Investors will require more detailed disclosures regarding GHG risks, and companies whose stock is publicly traded may need more robust climate change disclosures.

In a survey of US public registrants with revenues between $1 billion and $100 billion for annual filings occurring between 1 February 2009 and 13 September 2009, we noted that 150 companies discussed climate change in "Item 1A – Risk Factors". Of these reporting companies, 89 were energy and energy-related companies, suggesting that GHG issues represent a larger risk to energy companies than other companies.

Companies reporting climate change in Item 1A – Risk Factors

Of the Of the 150 companies discussing climate change in Item 1A-Risk Factors, the breakdown of sectors was as follows: [5]



Percentage of companies reporting climate change

The control environment for data accuracy related to reporting is equally as important as it is with measurement and monitoring. The reports generated for regulators and the information included in the Form 10-K should reconcile to supporting data. Failure to perform proper reconciliation could lead to incorrect reports and non compliance, resulting in fines or penalties.

The New York attorney general (AG) subpoenaed five energy companies in 2007 over concerns that GHG emissions would subject investors to risks not disclosed in the financial reports. The AG based this action on New York's 1921 Blue Sky Law (Martin Act), which does not require proof of *scienter* (knowing the illegality) as would a federal case. So far, the AG has settled with two utilities requiring climate change risk disclosures within the public filings (Form 10-K) of financial risks from regulation, litigation and physical impacts of climate change (e.g., rising sea level, weather).

Unlike the measurement and monitoring area, which typically use technology-assisted solutions, controls over reporting tend to be manual. This is due to the fact that company data needs to be populated in regulator-specific formats.

[5] In annual 10-K filings, Item 1A – Risk Factors.

Other compliance matters

The discussion above focuses on the day-to-day processes that should be in place to support an effective control environment for GHG emission reporting. However, it is also important to have an in-depth audit program in place to ensure that the control environment is operating effectively and to validate the accuracy of the reports. Such a program is also required by the 22 September 2009 US EPA mandatory GHG reporting rule. Leveraging specialized resources with environmental, compliance, reporting and internal control capabilities is key to performing an effective audit. In addition, experienced resources can assist companies in implementing leading practices that are observed in other organizations or industries.

Income tax considerations for cap-and-trade programs

As noted above, US-based electric utilities have been subject to a cap-and-trade program for SO2 and NOx emissions for many years pursuant to the CAA. The IRS issued guidance in the 1990s that provides a framework for the tax treatment of that program; however, there are important unanswered questions that would affect any cap-and-trade program. In addition, the guidance provided by the IRS is limited specifically to the CAA cap-and-trade program and may not be applicable to the more recent trading programs, such as RGGI or activities conducted outside of the US.

The income tax considerations surrounding a cap-and-trade program are similar to those that must be addressed for financial statement accounting and reporting. Income tax treatment is driven by recognition (is it income) and measurement (how much and when). Income tax treatment is also driven by the character of the income or loss from emissions activities – is the gain or loss capital or ordinary? In addition, there are international tax considerations when emission allowance or offset activity occurs outside the US by US-based companies or within the US by foreign-based companies. Similarly, companies must be aware of the state and local tax considerations of multi state activities.

Income tax treatment is driven by the design of the cap-and-trade program. Policymakers (Congress or the EPA) may decide to distribute the emission allowances at no cost, sell the allowances by auction or both – auction some and allocate some. This aspect of the program design is most important and will require determining whether emission allowances that are granted constitute gross income to the recipients of the allowances; and, if so, determining what period the allowances are included in income and, finally, determining how they are measured.

Another important aspect of the trading program design is establishing the compliance period (e.g., calendar year) for which the covered sources would be required to surrender emission allowances. Failure to surrender sufficient emission allowances for the compliance period gives rise to penalties. Once a compliance period is established, another consideration is whether emission allowances may be "banked" and carried forward to future compliance periods. Are the allowances "evergreen" or do they expire after a certain period? The answers to these questions may drive how the allowances are recovered (expensed) for income tax purposes.

One final aspect of the program design is whether offsets are permitted and how they may be created or certified. An offset is a measurable reduction, avoidance or sequestration of GHG emissions from a source not covered by the emission reduction program. For example, a company may engage in activities that will sequester GHG, such as planting trees in previously non-forested land, or invest in activities that avoid GHG emissions such as wind farms or solar panel energy production. If certified, these activities give rise to offset credits that may be used by a company as part of its emission allowances surrendered to meet its compliance obligation. Alternatively, the offset credit may be sold by the entity to another company to allow the buyer to meet its emission allowance requirement. How are the costs associated with the activity creating the offset credit treated for income tax purposes? Does the entity realize taxable income from the creation of the offset and, if so, when is the income recognized?

The following is a brief discussion of the possible tax treatment and the current guidance that may address the design and operating tax aspects of a cap-and-trade program in the US for GHG emission allowances.

Initial recognition at program inception

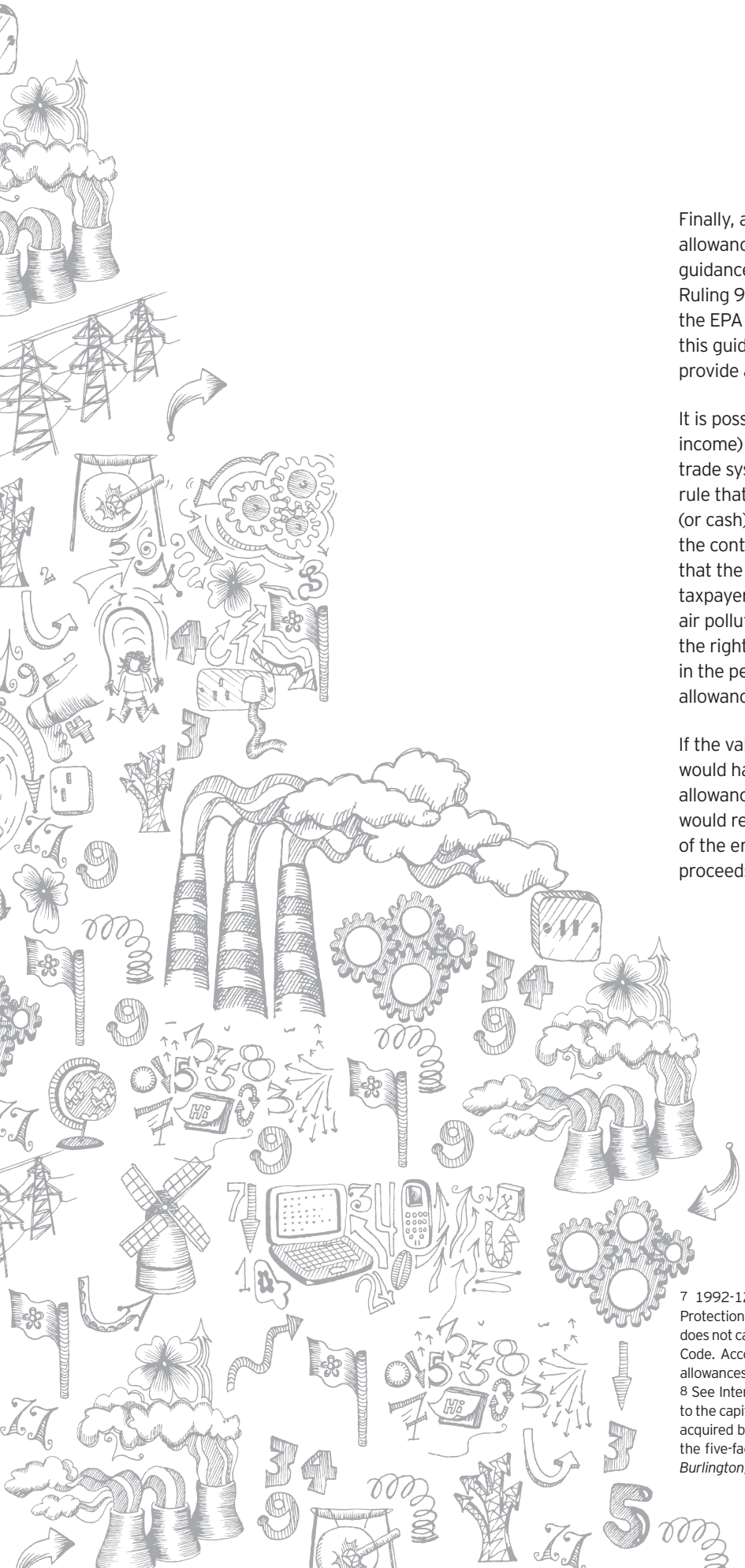
Assuming the emission allowance program provides for allocating a portion of the allowance free to the emitters, there are three alternatives that could be applied to the tax treatment. The allowances allocated free may be taxable in the period received (or granted). Alternatively, the free allowances could become taxable in the period they become first available for use (a design aspect of the program) or, finally, the receipt of the allowances is excluded from income of the recipient.

In general, under present law there are strong arguments that the value of the emission allowances freely allocated to a taxpayer would be taxable income in the tax year allocated to the recipient. Gross income includes "income" from any source derived, and current law defines income as any accession to wealth.[6] The emission allowances are intended to be freely traded and will be valuable financial instruments so, the recipient will have an "accession to wealth" as they are allocated. Assuming there is an active market for emission allowances, the value will be easily determined. Of course, if the emission allowances are included in income in the year received, there will be a corresponding increase in the tax basis of the allowances.

A taxpayer may realize a tax deduction for the tax basis in the year the allowance is surrendered in the relevant compliance period or perhaps will "amortize" the tax basis in the allowance over the compliance period if that period is longer than one year (for example the RGGI program uses a three-year compliance period). If the allowance is surrendered in the same tax period it is received, there could be no "mismatch" in income recognition and related expensing. However, if the taxpayer will not surrender the allowance until a later tax period (or if the allowance is amortized over a longer time frame) income could be recognized before the tax deduction, resulting in adverse cash flow implications which will incent taxpayers to monetize more of the emission allowances.

Another approach could be to treat the emission allowances granted free as taxable income in the year that they are surrendered or include them in income ratably over the compliance period. Although this approach is not consistent with the general tax principles, since the taxpayer has an accession to wealth when the allowances are allocated (allowances have value in the period in which they are allocated to a taxpayer), this approach would tend to reduce or eliminate adverse tax cash flow impact.

6 Internal Revenue Code Section 61; see also the holding in *Commissioner v. Glenshaw Glass Co.*, 348 U.S. 426 (1955).



Finally, a third alternative would be to exclude allocated emission allowances from income in the year received. The IRS issued guidance taking this approach with the SO2 and NOx. In Revenue Ruling 92-16,[7] the IRS ruled that emission allowances allocated by the EPA were not taxable income to the recipient. As noted above, this guidance is specific to the CAA program, and the IRS did not provide an explanation of its conclusions.

It is possible the IRS merely viewed this approach (exclusion from income) as the easiest way to deal with this aspect of the cap-and-trade system. However, there are limited exceptions to the general rule that would allow taxpayers to exclude the value of property (or cash) received from income.[8] It is important to note that in the context of the SO2 and NOx system, arguments were made that the granting of limited rights by the federal government to a taxpayer as a means to ration previously unrestricted rights to emit air pollution is not an accession to wealth so the value ascribed to the rights would not be included in gross income of the taxpayer in the period received. This same argument could apply to carbon allowances granted free as part of a new cap-and-trade program.

If the value is excluded from income, the allowance so received would have no tax basis, so the subsequent surrender of the allowance to satisfy the obligation under the cap-and-trade system would result in no tax deduction. In addition, the sale or exchange of the emission allowance would have no tax basis offset meaning proceeds from a sale are fully taxable in the year of sale.

7 1992-12 I.R.B. 5, "The allocation of emission allowances by the Environmental Protection Agency and their receipt by a utility pursuant to 42 U.S.C. Section 7651b (a) does not cause the utility to realize gross income under Section 61 of the Internal Revenue Code. Accordingly, under Section 1012 of the Code, a utility's basis in those emission allowances is not measured by reference to the fair market value of the allowances."

8 See Internal Revenue Code Section 118 where certain non-shareholder contributions to the capital of a corporation are excluded from income and reduce the basis of property acquired by the contribution. This exclusion is limited to certain contributions that meet the five-factor test outlined in the Supreme Court decision in *United States v. Chicago, Burlington, & Quincy R.R.*, 412 U.S. 401 (1973).

Tax aspects of cap-and-trade system operation

As noted, a taxpayer will have a tax basis in an emission allowance equal to the amount of income recognized upon the allocation, or the taxpayer will have a tax basis equal to the cost incurred to acquire the allowance if purchased in the open market. Under current law, this tax basis will be recovered (or deducted) by the taxpayer depending upon how the allowance is characterized by the holder. The allowance may be (1) inventory, (2) materials or supplies, (3) ordinary and necessary business expense (if not a material or supply), (4) amortizable intangible property or (5) intangible property with an indefinite life (not amortizable). This characterization and the related income tax treatment are similar to the issues noted for book accounting and financial reporting.

It is not likely an emission allowance would be considered inventory for income tax purposes unless the holder of the allowance is a "dealer" in emission allowances, since that characterization is generally applied to goods held for sale to customers in the ordinary course of business. Taxpayers who hold the allowance for surrender as part of their compliance could characterize the allowance as a material or supply. In that context, the basis in the allowance is expensed in the period it is "consumed" (surrendered as part of the compliance). It is important to note, however, that the IRS has concluded in a private letter, ruling that SO2 allowances were not supplies consumed in a taxpayer's trade or business but are instead capital assets because the allowances are not tangible property.[9]

However, a similar treatment (expensing when surrendered) could result if the allowances are characterized as ordinary necessary business expense. In that context, a taxpayer could account for emissions obligations by applying its general method of accounting. A liability (or obligation) is deductible when all events have occurred to fix the liability (i.e., the liability can be determined with reasonable accuracy and economic performance has occurred.) It would seem that these requirements are met when allowances are surrendered during or at the end of the compliance period.

If the allowance issued or acquired under a cap-and-trade program is treated as intangible property, the tax basis would be recovered either upon surrender, through amortization, or upon the sale or exchange. The tax basis of intangible property used in a taxpayer's trade or business that has a definable useful life would generally be recovered through amortization[10] . If the intangible is not eligible for amortization, the basis is generally recovered by sale or disposition (surrender).[11]

The IRS provided guidance on the tax treatment of SO2 allowances in Revenue Procedure 92-91.[12] In that guidance, the IRS concluded that the allowances were not depreciable or amortizable and that the tax basis is recovered in the period in which the allowance is applied against the emissions obligation.[13] The tax basis is also recovered in the sale or exchange of the emission allowance.

With respect to offsets, there is no specific guidance in current law that applies to the tax treatment of offsets. The cap-and-trade program for SO2 and NOx allowances does not have an offset program. There are many issues that need to be addressed when considering the tax aspects of an offset program. Must a taxpayer allocate a portion (or all) of the costs of an offset project to the tax basis in the offset credit? When are costs recognized (expensed or incurred, included in tax basis and recognized when the offset is sold)? What is the character of the gain or loss on the disposition of the offset received for a project? If there are ongoing maintenance costs associated with a project, are these costs deductible when incurred?

If the primary purpose of a project is to generate offsets to be sold to other emitters it would seem that the offset could be considered "inventory," requiring direct and indirect costs of production to be absorbed into the basis of the property produced. If the production of offsets is not the primary purpose of the project, is a taxpayer required to allocate a portion of its costs to the offsets created? There are several different approaches to the accounting for by-products or co-products for income tax purposes that need to be explored for any offset project.

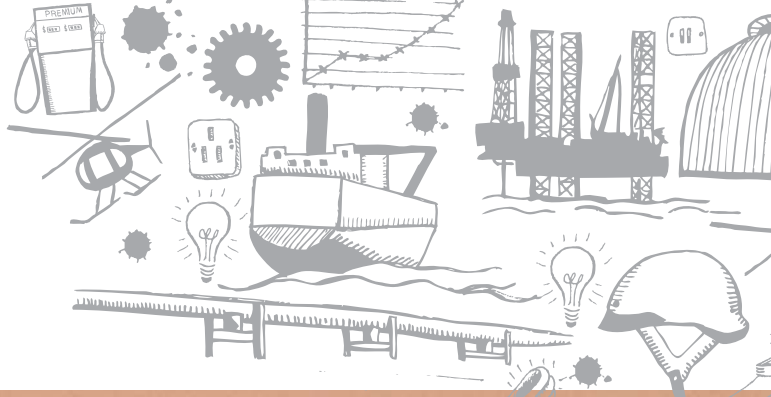
9 See TAM 200728032 (13 July 2007).

10 Intangible assets are generally amortized over the period of their useful life subject to the application of Section 197 which would mandate a 15-year amortization period. Emission allowances would generally be considered Section 197 intangibles as defined under Section 197(d)(1)(D). However, they may be carved out as 197 intangibles where certain rights are separately acquired outside of the acquisition of a trade or business. In that context, a right or contract that is of fixed duration of less than 15 years is not considered a 197 intangible and will fall within the general amortization rules for intangible property or recovered in a manner similar to "units of production." See Section 197(e)(4)(D).

11 However, if the emission allowance is acquired as part of the acquisition of a trade or business, the allowance would be treated as a Section 197 intangible subject to amortization of 15 years. No deduction would be allowed upon surrender unless the taxpayer held no other intangible property acquired in the acquisition at the time the allowance is surrendered.

12 1992-2 C.B. 503.

13 *Id.* See Q&A 2: "...an emission allowance has no ascertainable useful life over which it could be depreciated. Further, it is not subject to gradual exhaustion, wear or tear, or obsolescence over some determinable life within the meaning of Section 1.167 (a)-1 of the Income Tax Regulations, and its useful life is not limited as required by Section 1.167 (a)-3. Therefore, a unit-of-production method of depreciation is not appropriate."; Q&A 3: "A utility will generally be permitted to recover its basis in an emission allowance that is applied against sulfur dioxide emissions occurring in a particular year by deducting the amount of its tax basis in that emission allowance in the year that the sulfur dioxide was emitted."

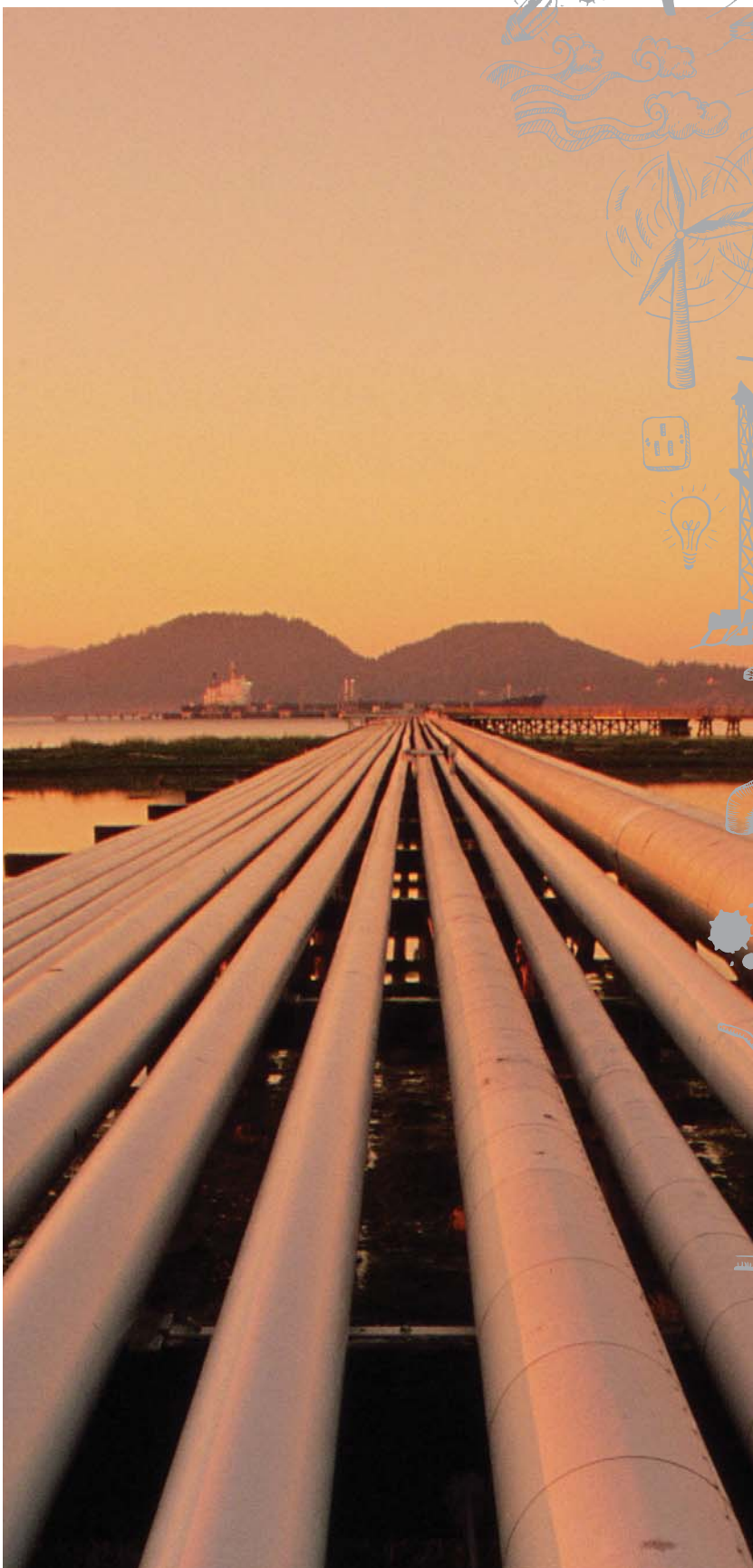


Sale or exchange of emission allowances

A very important aspect of a cap-and-trade program is the ability to trade the emission allowances in the market. This aspect allows companies to profit from their ability to reduce their emissions thereby reducing the cost of compliance. The tax aspects of trading emission allowances are driven by the character of the gains or losses realized from the trading activity. Are gains or losses associated with the trading of emission allowances capital or ordinary gain or loss? In general, capital losses may only be used to offset capital gain income, and individual taxpayers under current tax law enjoy favorable tax rates applied to net capital gain income. Consequently, the characterization of the gain is an important aspect of the trading program.

Under current law, the tax treatment of the sale of an emission allowance generally depends on the character of the asset in the hands of the seller at the time of the sale. A taxpayer may acquire emission allowances to satisfy its compliance requirements under the program either currently or in the future. Alternatively, a taxpayer may acquire emission allowances for investment, or certain taxpayers may purchase allowances as "dealers" in the allowances. Additionally, a taxpayer's purpose for acquiring the emission allowance may change over time — for example, from a purpose in use to satisfy its own obligations to a purpose for resale, banking for future needs or investment.

If the allowances are characterized as commodities and the taxpayer is a dealer in allowances, the character of any gain or loss to that taxpayer would be ordinary income or loss. Alternatively, if the taxpayer is not a dealer in commodities (allowances), then the character of the gain or loss will be driven by whether the allowances are held for use in the taxpayer's business and whether they are treated as depreciable property or held for investment.



As noted above, the IRS has taken the approach in its guidance for the tax treatment of SO2 allowances that the allowances are not depreciable assets and would be considered capital assets for all taxpayers except a dealer. Accordingly a taxpayer who holds SO2 allowances for use in its trade or business but subsequently sells the allowances will recognize a capital gain or loss on the disposition. In contrast, a dealer in emission allowances would recognize ordinary gain or loss on the disposition. [14]

Note that the IRS specifically provided that SO2 emission allowances that are part of the CAA program would constitute "like kind" property so that power and utility companies could "swap" allowances. For example, a utility may have a need for a particular vintage year allowance, so it would be able to swap a subsequent year's allowance to cover that need. Such an exchange of SO2 allowances would be a non recognition transaction to the utility. [15] This will be an important aspect of a cap-and-trade program to allow emitters to manage their compliance on a tax-efficient basis.

[14] *Id.* See Q&A 4: "Generally, a utility will recover its basis under Section 1001 of the Code on the sale or exchange of an emission allowance. Therefore, a utility will realize capital gain or loss on the sale or exchange of an emission allowance to the extent of the difference between the amount realized and the utility's adjusted basis in that allowance. If, however, the utility is holding an emission allowance primarily for sale to customers in the ordinary course of a trade or business of dealing in allowances, any gain or loss realized from the sale or exchange will be ordinary. The utility will recognize gain or loss in the year of the sale or exchange, unless a nonrecognition provision of the Code (such as Section 1031) applies."

[15] *Id.* See Q&A 5: "Emission allowances, regardless of the year to which the allowances are allocated by the EPA, will be treated as like-kind property for purposes of Section 1031 of the Code. Therefore, an exchange of emission allowances that would otherwise result in a taxable event and the recognition of gain or loss under Section 1001 is an exchange of like-kind property that qualifies for nonrecognition treatment under Section 1031, provided that the requirements of that section are otherwise satisfied."

Tax aspects of trading emission allowances and related derivatives

As noted above, the trading of emission allowances is a very important aspect of the program. The US has complex rules that govern the timing and character of gains or losses associated with commodity and securities trading that are driven by the nature of the underlying instruments. It is likely that there will be two primary categories of emissions trading instruments in the emissions markets: the actual allowances, which would include verified offset allowances, and allowance derivatives – futures and options. Allowances may trade on an existing exchange or trade "over the counter," or a new exchange may be created. Right now, it is not clear what agency may be the primary regulator for the market. It may fall under the Commodity Futures Trading Commission (CFTC), SEC, the FERC, or even the EPA.

Currently, futures contracts on SO2 and NOx emission allowances are traded on the Chicago Climate Futures Exchange. SO2 and NOx allowance futures and option contracts are also traded on the New York Mercantile Exchange (NYMEX). Both of these exchanges are designated contract markets and are regulated by the CFTC. The tax aspects of trading of allowances and related futures or options contracts are heavily influenced by these designations.

There are special rules for commodities dealers and traders that allow eligible taxpayers to apply "mark-to-market" accounting for their contracts. In general, the contracts are treated as if they were sold on the last day of the year for fair market value and any gain or loss taken into account. The gain or loss is treated as ordinary income or loss. Dealer and traders that do not elect mark-to-market accounting are generally taxed when the commodities are sold or exchanged.

Commodities derivatives are subject to a host of complex tax rules that generally require mark-to-market accounting for "Section 1256" contracts. [16] In general, Section 1256 requires taxpayers to treat each eligible contract as if it were sold (and repurchased) for its fair market value on the last day of the year. Any gain or loss is treated as short-term capital gain to the extent of 40% of the gain or loss and long-term capital gain or loss to the extent of the remaining 60% gain or loss. This rule does not apply to "hedging" transactions (taxpayers specifically identify the contract as a hedge in accordance with the regulations), a Section 1256 contract that is part of a "mixed straddle" if the taxpayer elects to have Section 1256 not apply, or any Section 1256 contract held by a dealer or trader in commodities that elects mark-to-market accounting.

The application of these rules to any emission allowance cap-and-trade program will be quite complex. As Congress considers carbon legislation, these issues should be discussed and guidance should be provided by the IRS to clarify how the trading activity will be treated for tax purposes.

16 See Internal Revenue Code Section 1256(g) for definitions of regulated futures contracts.

International tax considerations

As noted above, a cap-and-trade program will include a number of cross-border implications. One objective outlined in the current debate in Congress is to develop a program that would integrate with other cap-and-trade programs abroad. In addition, both proposals in Congress allow for compliance though international or offshore offset projects. Consequently, there will be cross border implications associated with any program enacted.

US-based multinationals will likely engage in offset programs offshore to generate offset credits that will either be used for US compliance or sold. US-based entities may also engage in emission allowance trading activity by buying and selling emission allowances on the open market. In addition, foreign-based multinationals with US business operations may conduct offset projects in the US or similarly engage in emission allowance trading in the US.

Under current law, the US applies a worldwide tax system under which a US-resident individual or domestic corporation is taxed on all income whether derived in the US or overseas. Income earned directly through a pass-through entity, such as a partnership, is taxed on a current basis. The US provides an important deferral regime for income earned indirectly through foreign corporations. Active income earned by the foreign subsidiary is generally not subject to US tax until it is distributed to the US owner/taxpayer.

There are many important and complex rules that override that general rule and subject certain types of income to current tax or extract a toll charge for the deferral. The cornerstone of the anti-deferral provisions in the US income tax rules is based on whether the income derived from an activity is "foreign personal holding company income" under the "subpart F" or Passive Foreign Investment Company (PFIC) rules. In the context of emission allowance activities, one will need to determine whether the income derived from the activity is foreign personal holding company income or not.

Specifically, if a foreign affiliate of a US-based multinational engages in an offset project and sells the offset credits, is that income subject to US as foreign personal holding company income? Similarly, if a foreign affiliate sells emission allowances, is the income subject to US tax as foreign personal holding company income? Of course there is very little guidance on this characterization of income from emission allowance activities.

In a private letter the IRS noted that the sale of surplus emission allowance under the European Union Emission Trading Scheme did not result in foreign personal holding company income. They based their reasoning on the fact that the emission allowances were intangible property used in the seller's active business so that the income from the sales of the surplus allowances was not foreign personal holding company income. The taxpayer argued that the sale of the allowances was excluded from foreign personal holding company income by reason of the exception for active gains or losses from the sale of commodities. [17]

In a similar manner, a foreign-based multinational may engage in offset projects in the US or engage in trading emission allowances in the US. Is the foreign entity subject to tax on the gains or losses realized from the sale of offset credits generated from projects in the US? Any effectively connected income from the conduct of a US trade or business is generally subject to US taxation on a net basis. If the foreign entity's activities did not constitute a US trade or business because they were more in the way of a passive investment, payments to the foreign entity could be subject to withholding tax on a gross basis unless subject to some exemption from withholding tax in a US income tax treaty. There are safe harbor exceptions to US taxation for foreign entities engaged in trading of securities and commodities in the US. If the emission allowances fall within those safe harbor exceptions, the gains or losses from trading would not be subject to US taxation.

Multinational businesses will likely engage in offset activities or trading activities for the purchase of emission allowances in one jurisdiction, then sell or otherwise transfer the allowances or offset credits to other members of the global groups (related parties). These related-party transactions are subject to the various arm's-length transaction standards applied in transfer pricing. If there is an active market for emission allowances and related offset credits, the transfer pricing may be a simple matter. However, a multinational may engage in an offset project because it has determined it can do so at less cost than acquiring emission allowances on the open market. Accordingly, there may be profit realized from the offset transfer that must be allocated appropriately between the jurisdictions affected by the intercompany transaction. All the facts and circumstances impacting the transaction – the functions and risks borne by the related parties – must be considered in establishing the proper transfer price.

17 PLR 200825009

Other issues

Tax-exempt organizations will likely be engaged in a range of issues involving a cap-and-trade program. Exempt organizations will have activities that create offsets, and they will have the ability to sell these offsets at a gain. Will this be tax-exempt income to the organization or will it be subject to income tax as "unrelated business taxable income"?

There are many tax-exempt electric cooperatives in the US who may receive free emission allowances as part of the cap-and-trade program. If it is determined that the granting of the emission allowance is income to the recipient, how does this affect the tax status of these electric cooperatives? Is this "member income"? And if not, does it impact their tax-exempt status? In a similar manner, if the emission allowances are deemed to be tax-free when allocated, how is income from a subsequent sale to be treated for purposes of determining tax-exempt status? [18]

Finally a cap-and-trade program will impose a penalty for failure to surrender sufficient emission allowances to cover emissions for the compliance period. Is a penalty paid in this context deductible? Payments to a government may be deductible if they are compensatory or if they are not punitive but are set as a means for compliance or to encourage compliance. [19] It is important to note that the IRS ruled that penalties imposed in the CAA SO2 and NOx emission program were not deductible. [20]

State and local tax considerations

In addition to the many US federal and international tax implications of a cap-and-trade program, there are many more state and local tax issues that one must consider. In general, the state taxable income base starts with federal taxable income so that all the federal income tax issues outlined above will have equal significance to the determination of taxable income for state income tax purposes. State income tax will also be driven by the characterization of the emission allowance for state income apportionment purposes. What is the nature of the emission allowances (property used in the trade or business) and how will they be sited for allocation and apportionment purposes? How will gains and losses from the sale or exchange be treated for state income tax purposes – business income or non-business income? Are the gains or losses apportioned or specifically allocated? If apportioned, will the receipts factor be included on a gross or net basis?

There are a host of other taxes that can be affected by emission allowances. Are the emission allowances subject to property tax? Are the allowances subject to use tax if consumed in the trade or business? Are the allowances subject to sales tax if sold?

Future tax considerations

This publication has only touched on some of the many tax aspects of a carbon trading program. The Staff of the Joint Committee on Taxation issued a report on 12 June 2009, *Climate Change Legislation: Tax Considerations*, which outlines many of the issues discussed in this paper in much more detail. The report was issued in advance of a public hearing by the Senate Committee on Finance (16 June 2009). At that hearing the Finance Committee heard testimony about the tax aspects of cap-and-trade legislation and the various technical and political issues. It is clear Congress is aware, and it is likely the tax aspects will be addressed in any final legislation.

It is too soon to speculate on where Congress will end up with respect to the critical tax issue – of whether the emission allowances that are given away free gross income to the recipients. In light of the budget issues facing the federal government, there will be a great deal of pressure to treat the allowances as taxable income. However, there are strong public policy arguments that support excluding the allowances from taxable income.

Once the taxability question is resolved, the remaining issues will also need to be addressed but can likely be done so through the Treasury and the IRS applying current tax concept to intangible property rights as well as the guidance provided under the SO2 and NOx trading program.

18 Electric cooperatives are generally tax-exempt under Section 501(c)(12) of the Internal Revenue Code but only if 85% or more of their income is derived from their members.
19 See Treas. Reg. 1.162-21(b) and Rev. Rul. 88-46, 1988-1 C.B. 76.
20 Rev. Proc. 92-91 Q&A 7: "The purpose of the $2,000 per ton penalty imposed by Section 411 of the Act is punitive as indicated by the legislative history accompanying the Act. See H.R. Rep. No. 490 (Part 2), 101st Cong., 2nd Sess. 5 (1990). Thus, this exaction is a penalty within the meaning of Section 162 (f) of the Code and Section 1.162-21 of the regulations, and is not deductible under Section 162 (a). However, the reduction of future emission allowances under Section 411 of the Act as a result of excess emissions is not a penalty within the meaning of Section 162 (f) and will not preclude any deduction of the basis of those allowances in the year of the reduction."

Conclusion

Carbon emissions management is becoming an increasingly important strategic objective for many companies. US lawmakers are focused on the issue, and additional legislation may be coming. In the interim, new mandatory GHG reporting requirements from the EPA took effect on 1 January 2010. To stay ahead of the curve, companies need to make sure they have fully embedded carbon considerations in their business strategy to ensure that climate change issues are properly addressed. This includes their risk management operations, day-to-day business, accounting and tax planning. The challenge will be to harmonize the various reporting frameworks that are used to avoid questions concerning discrepancies later.

It is also important to incorporate public perception of GHG emissions into the overall business plan and properly report emissions from a tax and financial disclosure perspective. Companies can benefit from alignment of their products/services with their customers, suppliers, neighbors, regulators and employees to increase enterprise value. This involves a gap analysis, not just for regulatory deficiencies, but for the environmental sustainability of the business.

These changes should be looked at for potential opportunities, as opposed to considering them strictly as costs of compliance. For example, consider what carbon reduction projects will generate a positive return on investment or the potential tax credits for energy reduction projects. It is also possible that additional product or service lines could be developed in the process, creating new sources of revenue such as the capturing, storing, and selling of emissions themselves and/or trading emissions credits.

In regard to compliance, companies need to evaluate their environmental compliance programs and internal controls. With new regulations, including the potential for increased enforcement, it is important that these programs be updated and monitored as well. The green strategy is becoming a more and more important part of the overall business strategy. To maximize the value of the GHG programs, an overall GHG strategic approach is warranted.

Ernst & Young is committed to working with our clients as the regulatory and legislative efforts addressing carbon emissions and climate change unfold. For further information and assistance, please contact any of the individuals listed on the next page.

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About our Climate Change and Sustainability Services

Our climate change and sustainability services team is grounded in our core skills in assurance, tax, transactions and advisory. On top of that, we have the specific knowledge to help you understand business and regulatory threats and opportunities, explore and execute commercial transactions, monitor performance and assure public disclosures on progress. You'll receive tailored service supported by global methodologies to address issues relating to your specific needs. Wherever you are in the world, we will provide the right professionals to support you.

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