RGGI Consumer Allocation Approach

Overview

The RGGI Memorandum of Understanding (MOU) establishes a regional emissions budget (the cap), and apportions the emissions budget among participating states. Each participating state will allocate allowances up to the amount of its emissions budget, with each allowance allowing a regulated source to emit one ton of CO_2. While the MOU sets certain requirements for allowance allocation, participating states are given broad discretion in how they allocate allowances.

Historically, cap-and-trade programs have allocated allowances directly to regulated emissions sources based on metrics related to historic operation (e.g., heat input, generation output, or emissions), a practice commonly referred to as "grandfathering."[1] RGGI design takes a new approach. The RGGI MOU and model rule require that participating states allocate a minimum of 25% of allowances to support a "consumer benefit or strategic energy purpose," referred to here generally as a "consumer benefit allocation."[2] These allowances would not be allocated directly to electric generators subject to the program. Instead, generators would be required to purchase allowances, most likely through a regional auction.[3] Revenue from the sale of these allowances would be used to provide programmatic support for energy efficiency and clean energy technologies, which would reduce the overall compliance costs of the program and its impact on electricity ratepayers.

Participating states have discretion in how they define a consumer benefit allocation (within the guidelines stated in the RGGI MOU), the percentage of allowances to be allocated to support such purpose(s), and how this allocation approach is administered. Participating states would have full discretion in how they allocate any remaining allowances.

A consumer benefit allocation approach is warranted by the deregulation of the electric power sector, as well as fundamental differences between a cap-and-

[1] The Acid Rain Program auctions approximately 2.8% of allowances to facilitate price discovery. However, the revenue from this auction is returned to regulated sources on a pro rata basis.
[2] The RGGI MOU includes the following: "[Each] Signatory State agrees that 25% of the allowances will be allocated for a consumer benefit or strategic energy purpose. Consumer benefit or strategic energy purposes include the use of allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon-emitting energy technologies, to stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or to fund administration of this Program…."
[3] RGGI-participating states are currently cooperating in the design of a regional auction. Allowances could also be allocated directly to non-regulated parties to provide a direct incentive.

trade program for carbon versus other pollutants. A consumer benefit allocation approach is also critical to the success of the RGGI program. No end-of-stack controls are now commercially available to limit CO_2 emissions.[4] As a result, a CO_2 cap-and-trade program will benefit from having a strong end-use component integrated into its design. A consumer allocation approach allows RGGI to adopt both a supply-side (electricity generation) and demand-side (electricity use) focus, facilitating the achievement of emissions reductions at least cost.

Market Rationale

The primary argument for a consumer benefit allocation, as demonstrated by economic theory and historic experience, is that in competitive wholesale electricity markets ratepayers will ultimately bear the compliance costs of a cap-and-trade program whether allocations are granted for free or generators are required to purchase allowances. Grandfathering allowances, therefore, results in a significant transfer of assets from ratepayers to electric generators without lowering the impact of an emissions cap on wholesale electricity prices. This transfer is expected to be considerably larger than those realized through existing cap-and-trade programs addressing sulfur dioxide and nitrogen oxides emissions.

A consumer benefit allocation is supported by two key factors that make the context for a carbon cap-and-trade program designed today different than that faced when designing the Acid Rain Program and the OTC NO_x Budget Program, which addressed sulfur dioxide and nitrogen oxide pollution, respectively.

The Acid Rain Program and NO_x Budget Program envisioned significantly larger reductions, on a percentage basis, than the RGGI carbon cap-and-trade program requires. As a result, the size of the allowance budget relative to current emissions at the onset of these programs was smaller than that envisioned for a carbon cap-and-trade program.

In a cap-and-trade program, the compliance costs necessary to meet a cap result in a marginal cost of emissions reductions; this marginal cost is represented by the price of allowances in the market. In a criteria pollutant program envisioning 30% to 60% reductions, for example, the aggregate value of the allowance budget may be more than twice the total cost of compliance. In a carbon cap-and-trade program envisioning smaller initial reductions (e.g., 10% relative to current emissions), the value of the emissions budget relative to compliance costs may be many times that of compliance costs (Figure 1). Thus, a carbon cap-and-trade program presents a fundamentally different relationship between

[4] There are emerging end-of-stack options in the early commercialization and deployment phase. Absent end-of-stack controls, a number of compliance options are available to electric generators subject to RGGI, including heat rate improvements, fuel switching, co-firing of biofuels, environmental dispatch of a company portfolio of units that considers the CO_2 emissions rate of individual units, and the use of emissions offsets.

compliance costs and the value of the emissions budget than past cap-and-trade programs.[5]

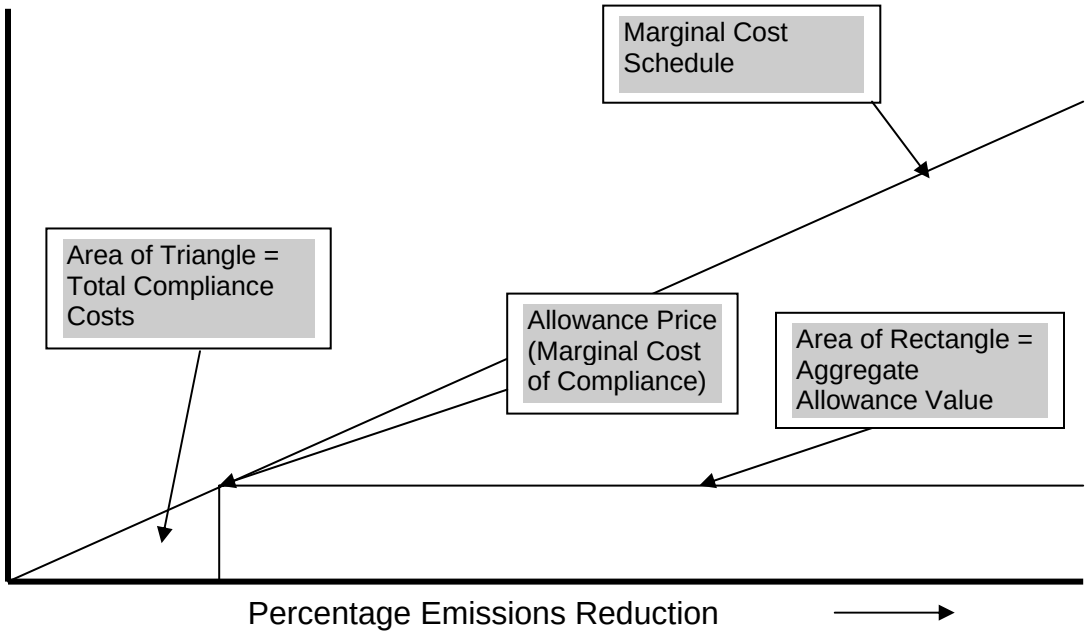

Figure 1. Illustrative Value of Emissions Allowances Relative to Total Compliance Costs for a Carbon Cap-and-Trade Program

The Acid Rain and NO_x Budget programs were also developed prior to the development of competitive wholesale electricity markets and the widespread advent of electricity restructuring.[6] These programs were developed in the context of cost-of-service regulatory regimes. Under cost of service regulation, public utility commissions could prevent integrated electric power companies from passing on the "opportunity cost" of grandfathered allowances to electricity ratepayers. In contrast, RGGI is being developed in a restructured region with competitive wholesale electricity markets. In a competitive wholesale generation market, generators will pass on the value of allowances as a cost of generation, whether these allowances are allocated at no cost or generators are required to

[5] The value of the 2002 OTC NO_x Budget Program emissions budget for states now participating in RGGI was approximately $92 million, based on an emissions budget of 123 thousand tons and an allowance price of $750/ton. By comparison, the RGGI emissions budget is projected to have a value of $375 to $560 million annually through 2014, based on an emissions budget of 188 million tons and an allowance price of $2 to $3/ton.

[6] The OTC states signed an MOU in September 1994 committing to achieve regional emissions reductions of NO_x. A NO_x emissions budget for the OTC region was established in June 1995 and the Phase I cap-and-trade program began in 1999. The Phase I cap-and-trade program for the Acid Rain Program began in 1995; Phase II of the program began in 2000. PJM implemented a competitive wholesale electricity market in 1997; ISO New England and NY ISO implemented competitive wholesale markets in 1999. Restructuring legislation introducing retail competition in the RGGI states (excluding Vermont and portions of New Hampshire) was passed during the period from 1996 through 1999.

purchase allowances in the market. Regulators do not have the authority to prevent such an outcome in a restructured electricity sector.

In a competitive wholesale market, the independent system operator (manager of both the power grid and power market) solicits bids for generation to meet expected electricity load on a daily and hourly basis. Bids are accepted based on price and amount of available generation, until the expected load is met. The price of the most expensive generator that dispatches to meet system load is considered the marginal unit and sets the market-clearing price. All generators receive this market-clearing price, even if their generation costs are significantly lower than the marginal unit.

Generally, a generator's bid price in the wholesale electricity market is determined by the short-run variable costs incurred by the generator to supply the electricity. The amount of a generator's bid will include the incremental cost of fuel, operation and maintenance, and emissions allowances. A generator will include in its bid the value of the emissions allowances that would be expended when generating electricity, even if the generator has received the allowances at no cost. This is because the dispatch of the electric generation unit would require future submission of allowances to the regulatory authority, and therefore dispatch of the unit imposes an "opportunity cost" since allowances that are expended cannot be sold in the market and therefore potential revenue is lost. This outcome is consistent with how a competitive market is intended to work.

Because the value of allowances is included as a cost in a generator's bid into the wholesale market, the realized wholesale price of electricity is the same whether the allowances are distributed at no cost to generators or generators must purchase the allowances.

The cost of complying with a carbon constraint will increase the cost of wholesale power, since fossil-fired units are typically the marginal unit. This increase in wholesale power prices will increase revenue for all generators, even those that are not subject to the cap-and-trade program. Many generators subject to the cap-and-trade program may be able to fully recover their compliance costs through this increase in revenue. To the extent that the increase in wholesale market-clearing price exceeds a unit's increase in generation costs due to CO_2 compliance, a unit will see an increase in net revenues.

All generators not subject to the program will realize an increase in net revenues due to an increase in wholesale electricity prices. Because RGGI-regulated generators will recover a portion or all of their compliance costs, and non-regulated generators will realize an increase in net revenues, the electric generation sector as a whole may be able to recover all of its aggregate CO_2 compliance costs, even if all allowances must be purchased. The amount of compliance costs that can be recovered by different types of regulated generators (coal, oil, gas) depends on the relative carbon emissions rate of the

marginal unit in relation to other units that also dispatch. For example, if a natural gas combined cycle unit is on the margin, a coal-fired unit would be able to recover less than half of its compliance costs, while the natural gas-fired unit would recover all of its compliance costs.[7] Conversely, if a coal- or oil-fired generation unit is on the margin, a natural gas-fired unit would realize an increase in net revenue, since the CO_2 compliance cost adder to the wholesale electricity price ($/MWh) would exceed the unit's ($/MWh) CO_2 compliance cost.

The impact on cost recovery depends in large part on which types of units are expected to be on the margin for a given period over the course of a year.[8] The ability to recover compliance costs should also be considered on a company portfolio basis, especially for companies that own a portfolio of both fossil and non-emitting units. A loss in net revenue at one plant may be counter balanced by an increase in net revenue at another plant, and may provide an increase in net revenue for the company as a whole.

A number of market variables determine which generator is the marginal unit, and therefore impact the level of CO_2 allowance value "pass through" to wholesale electricity prices. However, the basic dynamics elaborated here have been borne out in the initial experience of the European Union Emissions Trading Scheme (EU ETS) for carbon. Recent research, based on both empirical observation and power sector modeling, indicates that pass-through rates of carbon allowance price to wholesale electricity price in the European electricity market range from 60-100% of CO_2 allowance opportunity costs.[9] Modeling of the European electricity sector also indicates that even if generators are required to purchase all allowances, sectoral profits may increase.[10] The failure to auction allowances in the European system has recently generated significant controversy, based on indications that the profitability of the European electric generating sector has increased significantly under the EU ETS.[11]

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[7] Based on average emissions rates in the U.S. by fuel type (U.S. EPA eGRID 2000 data), a $3/ton allowance price translates to compliance costs of approximately $3/MWh for coal-fired units, $2.20/MWh for oil-fired units, and $1.50/MWh for gas-fired units. A new natural gas combined cycle plant, with an emissions rate of approximately 800 lbs. CO_2/MWh, would incur compliance costs of $1.20/MWh assuming a $3/ton allowance price.

[8] For example, in PJM during 2000-2005 the following types of EGUs were on the margin for the following periods of time: coal – 49-62%; natural gas – 18-31%; oil – 11-32%. See PJM, *2005 State of the Market Report*, March 2006.

[9] Sijm et al., "CO_2 cost pass through and windfall profits in the power sector," Climate Policy 6 (2006): 49-72; Sijm et al., *CO_2 Price Dynamics: The Implications of EU Emissions Trading for the Price of Electricity*, Energy Research Centre of the Netherlands, September 2005. Variations in estimates depend on the regional electricity market evaluated and temporal distinctions. See also, Martinez, K. and K. Neuhoff, "Allocation of carbon emission certificates in the power sector: how generators profit from grandfathered rights," Climate Policy 5 (2005): 61-78.

[10] This is because units with low carbon intensities also benefit from the increase in wholesale prices from the marginal fossil-fired unit. See Sijm et al., "CO_2 cost pass through and windfall profits."

[11] See, for example, UK House of Commons, Environmental Audit Committee, *The International Challenge of Climate Change: UK Leadership in the G8 & EU*, March 27, 2005, pp. Ev 155-156; Ev 159-161.

It should be noted that the dynamics outlined above may not apply to all electric generators, at least at the outset of the RGGI program. A number of power plants in the RGGI region are subject to long-term bilateral power purchase agreements (PPAs).[12] PPAs typically involve provision of a minimum fixed amount of energy and capacity to a purchaser that is subject to a fixed price per MWh of energy and MW of capacity, often with an adjustment for variations in fuel costs.[13] As a result, generators subject to long-term, fixed-price PPAs do not factor in the opportunity costs of allowances when determining dispatch costs and generation price offered.[14] Many of these contracts are currently considered to be "above market," providing generators larger revenues than would be available through the spot market. Over time, it is likely that CO_2 allowance costs will be factored into wholesale prices either when PPAs are renewed, renegotiated, or terminated.

However, the inability to directly pass through CO_2 allowance value to the wholesale market does not necessarily mean that generators subject to PPAs have not evaluated the potential for CO_2 compliance costs to impact their dispatch costs, or do not have the ability to adjust or renegotiate contracts based on the imposition of new costs.

In the past several years, there have been a number of new federal and state regulations imposing limits on emissions from power plants. Based on discussions with experts in the industry involved in the negotiation of such long-term contracts, it is not uncommon for a supplier to negotiate for a "re-opener" or "change-in-law" provision in such contracts that would enable the supplier to renegotiate the price or pass on unforeseen costs incurred because of a change in law like RGGI. In cases where no such re-opener is included in the contract, it is arguably likely that the supplier of the electricity under the contract has assumed the risk of any change in law that occurs during the term of the contract and factored this risk into the negotiated power supply price. Indeed, placement of risk between two parties is a central theme in any long-term power contract negotiation and change-in-law is a central risk in an industry like electric generation where the regulatory environment has always been a changing factor.

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[12] It is estimated that long-term contracts currently account for approximately 14% of electricity generation in the RGGI region, and could account for approximately 12% of regional generation in 2010. See Wilson et al., *The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative*, Resources for the Future Discussion Paper, August 2005.

[13] In recent years, many fixed-price PPAs have been renegotiated to a market-based rate based on realized locational marginal prices in the wholesale market. These renegotiated contracts often grant generators the flexibility to dispatch on a merchant basis in exchange for reducing the price paid by the purchaser for delivered firm energy and capacity. The PPA seller retains the responsibility for providing energy and capacity to the purchaser from either the generation facility or other generation resources within the ISO.

[14] Some generators with long-term PPAs also do not control the dispatch of the unit. Such generators, subject to "dispatchable" contracts, are unable to modify their dispatch in response to CO_2 price signals.

Multiple power plants that would be subject to RGGI, and that are also subject to long-term fixed-price PPAs, were sold in recent years after the proposed RGGI program was already well publicized. Appropriate due diligence would factor possible CO_2 compliance costs into an evaluation of the future profitability of these assets.

Since 1992, when the United States signed the UN Framework Convention on Climate Change and the U.S. Senate ratified it, and perhaps earlier, it is reasonable to presume that any negotiator of a long-term contract to supply power from a fossil-fuel-burning source should have either negotiated a re-opener provision for changes in law, or a risk premium to cover the eventuality.

Program Benefits

The initial emissions budget for a 10-state RGGI program would have an aggregate value of approximately $375 million to $560 million annually through 2014.[15] Utilization of a portion or all of RGGI allowance value could provide for a significant expansion of support for energy efficiency and clean energy technologies in the RGGI region.

Using RGGI allowance value to reduce electricity demand in the region is expected to reduce the aggregate cost of meeting the RGGI emissions cap and result in lower CO_2 allowance prices over time. A reduction in electricity demand is also expected to mitigate potential emissions leakage. To the degree that electricity demand is reduced, the demand placed on existing generation resources is reduced, and the need to develop new generation capacity is avoided. This reduction in demand for generation supply results in avoided emissions, which, in turn, reduces the demand for CO_2 allowances and lowers the realized CO_2 allowance price. This would mitigate potential emissions leakage by reducing the generation cost differential imposed on RGGI-affected generation units relative to generation units that are not subject to a carbon constraint.

Analysis conducted by the RGGI Staff Working group, including quantitative energy sector modeling, indicates that aggressive reduction of electrical demand in the RGGI region would lower RGGI CO_2 compliance costs, as represented by projected allowance prices, and could fully mitigate potential emissions leakage.[16]

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[15] Energy sector modeling conducted for the RGGI Staff Working Group using the Integrated Planning Model (IPM) projects allowance prices of $3/ton in 2015, rising from $2/ton in 2009 at the program's outset.

[16] IPM modeling results evaluating a high-efficiency scenario indicated that an 8.8% reduction in 2021 electricity demand in the RGGI region, relative to projected business-as-usual demand, would result in a significant reduction in CO_2 allowance prices and prevent any incremental increase in power imports and related emissions leakage. See, "Updated Reference and Sensitivities," September 8, 2005, available at http://www.rggi.org/docs/ipm_docs_results_9_8_05.ppt