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**State Commission Electricity Regulation
Under a Federal Greenhouse Gas
Cap-and-Trade Policy**

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State Commission Electricity Regulation Under a Federal GHG Cap-and-Trade Policy

Executive Summary

I. Introduction

Climate change policy will fundamentally affect the way that electricity is generated in the United States. A strong scientific consensus on the nature and magnitude of the challenges raised by anthropogenic climate change is the key driver of the increasing likelihood of federal policy to limit greenhouse gases (GHGs). Elected officials, businesses, non-governmental organizations, and policy analysts and scholars are increasingly in general agreement that a mandatory policy that puts explicit limits on GHGs, or puts a price on GHG emissions, is an essential component of a federal policy response. A cap-and-trade system for GHGs is the most likely policy response.

II. GHG Cap-and-Trade Policies and Compliance Responses

The way that a cap-and-trade system affects the electric industry and the end users of electricity depends on how the system is designed and implemented. One key metric of the system is the price of allowances, which is influenced by the strictness of the quantitative limit on emissions and the percentage of total emissions that must be covered by allowances. Stricter limits increase allowance prices, causing larger increases in the end user price of electricity.

Cap-and-trade systems can track emissions against the number of allowances held at the point where GHGs enter the atmosphere (referred to as a downstream administration) or at the point where fossil fuels enter the economy (upstream administration). Upstream administration has the advantage that it can efficiently cover transportation and other sectors that have many small emitters, while downstream measurement is generally difficult and expensive. Downstream administration is easy to implement in the electric industry, where most generation units are already required to have monitors that can measure GHGs.

The design element of a federal cap-and-trade having the largest financial effect on the electric industry is the way that the government initially allocates emissions allowances. Allowances could be sold by the government to raise revenue or conferred without cost to generation owners and/or Local Distribution Companies (LDCs). No-cost allowances could be distributed on the basis of any combination of historical GHG emissions, fuel inputs, or past electricity output, or updated each year based on recent output levels.

The electric industry can respond to GHG limits through a combination of decreasing the GHG emissions intensity of current generation capital, building new generation capacity that emits fewer GHGs, purchasing emissions allowances, and reducing energy consumption from end users. Carbon capture and storage (CCS), a technology that removes GHGs from fossil fuel emissions and stores

them permanently so as to prevent their entering the atmosphere, is a promising option whose economic and environmental effectiveness have yet to be proven at commercial scale.¹ The most efficient combination of these responses will be driven by technology development, geographical differences, the price of allowances, regulatory and tax treatment, and other economic factors. There is very little chance that the existing electric industry capital stock can comply with even very moderate GHG emissions limits without some combination of these other compliance responses.

There are a number of policy options that provide additional compliance choices. Allowance recipients could bank them from the present for use in the future. Allowances slated for future allocation could be “borrowed” for use in compliance in the present. Offset allowances could be created through GHG reductions by entities not covered by the system, increasing the number of allowances available for compliance. A mechanism called a “safety valve” could make additional allowances available at a pre-determined price if compliance proves more economically difficult than expected. A cap-and-trade system can incorporate any combination of these mechanisms to provide compliance flexibility.

III. Cap-and-Trade, Regulatory Decision-Making, and End-Use Pricing

Commission influence on the compliance and pricing decisions of generation owners are different for embedded cost ratemaking regulation than for generation sold through market pricing institutions. In the near term, commissions will have to make decisions about approval of new generation technology under embedded cost ratemaking with considerable uncertainty about a GHG cap-and-trade program and allowance prices. The cost of generation will depend on allowance prices and the effectiveness of new and rapidly developing technologies. Commissions need to balance carefully how to apportion risk between ratepayers and shareholders; otherwise they risk unintentionally increasing the incentives for power production under market pricing regimes relative to power produced under embedded cost ratemaking.

The choice of ratemaking techniques will depend directly on allowance prices. Under embedded cost ratemaking, a larger quantity of allowances allocated to the electric industry at no cost gives commissions more latitude to limit retail electricity price increases. This result holds regardless of whether the cap-and-trade is administered upstream or at the level of generation units or LDCs. Commission decisions about how to treat income received for the sale of allowances affect compliance incentives.

Commission decisions will influence end user conservation in two ways. The use of demand side management funded by generation owners or LDCs with commission approval will tend to increase rates even when it is an efficient means of GHG reductions, due to the traditional ratemaking practice of dividing the revenue requirement by the units sold. Commission decisions about how no-cost allowances are used in ratemaking will set the balance between cushioning end

¹ CO₂ from fossil fuel combustion has been successfully used to enhance oil and gas recovery, but the scale and geographical location of storage needed to make this a significant mitigation technology will require solutions outside the oil and gas industry.

users (lower rates) and transmitting economically efficient conservation incentives (rates that reflect the full cost of allowances).

Generation owners operating under market pricing will receive higher prices for their output because the marginal cost of production will include the cost of allowances. When these generation owners receive allowances they do not have to pay for, their profits will increase.

Commissions will not be able to influence the rates paid for electricity produced under market pricing when generation owners receive allowances at no cost. If allowances are instead allocated to LDCs in their role as entities obligated to physically provide electricity to end use loads, commission will be able to treat symmetrically electricity produced under embedded cost ratemaking and market pricing. Commissions will need to decide the balance between lower rates and efficient conservation incentives when regulating LDC use of no-cost allowances.

IV. Commission Interest in Cap-and-Trade Design Elements

Commissions have an interest in advocating a GHG cap-and-trade program that covers the largest possible share of U.S. GHG emissions, and not just electricity production. An electricity-only system will allow the inefficient leakage of generation from the electric industry to alternative energy production not covered by the narrow system. A broader system would prevent such inefficiency and find the most efficient GHG reductions throughout the economy.

Commission also have an interest in advocating that any allowances allocated to the electric industry at no cost should be allocated to LDCs and not to the owners of generation. Allocating allowances in this way gives commissions the ability to treat end users of electricity from different pricing regimes more equitably.

V. Compatibility with other State and National Mandatory Policies

A national cap-and-trade policy can coexist with state and national energy portfolio standards without difficulty. The simultaneous implementation of a national cap-and-trade with regional cap-and-trades like the Regional Greenhouse Gas Initiative of the proposed Western Consortium is more problematic and will depend on details that have yet to be worked out.

VI. Conclusion

Mandatory limits on GHGs will be a part of energy production and use for a very long time. The electric industry has begun to consider how it will navigate living with these limits. There is currently uncertainty about the timing and severity of GHG constraints on electric generation that will result from a federal program. Commissions need to understand how their mission will be affected by federal policy and to begin to craft strategies and procedures to best serve the public interest in this new environment.

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State Commission Electricity Regulation under a Federal GHG Cap-and-Trade Policy

I. Introduction

Climate change policy will fundamentally affect the way that electricity is generated in the United States. The purpose of this document is to explain the key issues that state utility regulators must understand in order to make informed decisions in the light of likely federal climate change policy. The fundamental driver of policy change is the scientific consensus about climate change, which has both strengthened and broadened consistently over the past two decades. While there remains substantial uncertainty about many aspects of the relationship between human activities and unprecedented effects on climatic systems, this consensus² overwhelmingly finds that

- the Earth's climate has already changed discontinuously beyond normal historical bounds
- these changes will become significantly greater over time
- a major part of observed and predicted changes comes from human activities that have increased the concentration of greenhouse gasses (GHGs) in the atmosphere
- the effects of predicated changes in the earth's climate will have serious and negative environmental and economic consequences

This scientific consensus has in turn driven a strong normative finding by both social and natural scientists that the prudent course of action is to reduce the level of GHG emissions with the aim of stabilizing GHG concentrations. This central idea has been widely endorsed by political leadership around the world. The actions needed to actually bring about significant reductions in GHGs are politically difficult and have economic costs. Industrialized countries are in various stages of planning and implementing policies to achieve GHG reductions (see Box 1).

The United States has very visibly chosen not to participate in the highest-profile international GHG reduction effort, the Kyoto Protocol. There has been a growing call for significant domestic policy on climate change from leaders from both political parties, and an increasing number of legislative proposals to impose a mandatory program at the federal level.³ These calls have been supported not only by environmental NGOs but also by significant parts of the U.S.

² An excellent general reference is the *IPCC Fourth Assessment Report on the Physical Basis of Climate Change – Summary for Policymakers* available at <http://www.ipcc.ch/>. Another source, the *Stern Review*, provides a readable and comprehensive, although somewhat controversial, reference on economics and policy.

[http://www.hm-treasury.gov.uk/independent_reviews/stern_review_economics_climate_change/stern_review_index.cfm]

³ The Pew Center on Global Climate Change maintains a discussion of current Congressional proposals at http://www.pewclimate.org/what_s_being_done/in_the_congress/110thcongress.cfm. The National Association of Clean Air Agencies has a recent comparison of bills available at <http://www.4cleanair.org/Documents/GWlegislationsidebyside.pdf>.

business community.⁴ The legislative proposals for mandatory action are all built around cap-and-trade policies covering the emissions of carbon dioxide, and include other GHGs to varying degrees.

Box 1: U.S. Policy in the International Context

The United States, along with 188 other countries, has ratified the United Nations Framework Convention on Climate Change (UNFCCC). This treaty expresses a commitment to reduce GHG emissions, but has no binding measures. The Kyoto Protocol to the UNFCCC does contain binding measures for industrialized countries, and has been ratified by the great majority of nations, although not by the United States and Australia. The Protocol is built around cap-and-trade architecture, with industrialized countries being obligated to hold emission permits to cover their total emissions, and international trade in allowances as one of the central avenues of compliance. The Kyoto Protocol's specific GHG limitations are for the period 2008-2012. Discussions and negotiations to set limits and supporting policies for subsequent periods have not yet yielded any agreement.

The countries that did take on obligations to meet specific targets have had mixed success in adopting effective policies. The European Union instituted an Emissions Trading System (ETS) for electric utilities and large industrial sources at the beginning of 2005. A follow-on system integrated with Kyoto Protocol allowance trading and tracking will take effect at the beginning of 2008. Sweden and Denmark also have implemented carbon taxes independently. CO2 emissions are implicitly taxed through levies on fuel sources (as they are in the U.S.), with gasoline generally having the highest implicit rate of carbon taxation, diesel (due to the political implications of its importance in commercial transport) taxed at a significantly lower rate, and coal taxed very lightly or not at all. The EU has made significant progress in reducing its stationary source CO2 emissions from business as usual, but has had less success with its transportation sector. The EU as a whole is generally thought to be unlikely to meet its Kyoto Protocol obligations without significant purchases of allowances from Russia and the Ukraine.

Other industrialized countries have had significantly less success in implementing policies. Canada had planned an emissions trading system for GHGs but the new Conservative government abandoned the plan. Quebec recently passed a province-wide carbon tax levied on all fossil fuels and is set to implement the policy in October of 2007. New Zealand announced a carbon tax, but similar to Canada abandoned the plan before implementation. Japan also seriously considered a carbon tax but so far has failed to implement it. All of these countries appear unlikely to meet their Kyoto Protocol obligations from domestic reductions; how they use the international emissions trading system remains to be seen. The Australian province of New South Wales has operated a utility-only cap-and-trade system since 2003, even though Australia has not ratified the Kyoto Protocol. The cap in this system is indexed to the provincial population as well as to emissions per capita.

U.S. non-participation in the Kyoto Protocol has been a factor of the highest importance. The U.S. is the world's largest economy and accounts for a significant percentage of world GHG emissions (22% of world CO2 emissions from fossil fuel consumption in 2004). One of the factors affecting both developed and developing country willingness to engage in GHG reductions is the role of the U.S.. Passage of a national cap-and-trade policy would increase the influence of the U.S. in negotiations on the shape of any international agreements that follow the Kyoto Protocol, and increase the chances that other developed nations will follow our lead. In short, such a program would almost certainly increase U.S. leadership on the issue of climate

A. Role of the electric sector

The generation of electricity accounted for 40% of total U.S. CO2 emissions in 2005, and about one-third of overall GHG emissions (CO2 accounts for about 84% of U.S. GHGs in the most

⁴ One good example of industry support can be seen at <http://www.us-cap.org/>, which includes a number of major electric utility companies.

recent U.S. Energy Information Administration estimates for 2005). The bulk of these emissions (82%) come from coal combustion, reflecting coal's dominant position in electricity generation and its higher CO₂ content per unit of heat output than oil or natural gas. Natural gas accounted for 13% of utility CO₂ emissions, with petroleum representing about 4% and very small amounts from electricity derived from geothermal sources and municipal solid waste combustion.⁵

Utilities have received primary attention for mandatory GHG reduction policies for at least three reasons. First, there is a significant history of environmental regulation of utilities, including the most well known example of cap-and-trade policies to date, the Acid Rain Trading Program for SO₂ created by the Clean Air Act Amendments of 1990. Second, the number of entities that directly emit GHGs is relatively small compared to the next largest emitting sector, transportation, making regulation less logistically challenging. Third, the status of utilities as entities that have historically been regulated in the public interest makes further regulation less politically controversial than for other sectors.

B. Implications of GHG policy for utility regulation

If limitations on CO₂ emissions are to be an important and long-lasting aspect of electricity generation, state regulators must fully understand how federal regulatory actions affect the decisions that they make. This report will provide information and analysis of four key areas. Part II begins by explaining the key choices that must be made in crafting a national cap-and-trade policy for CO₂. The implications of policy for approval, prudence review and ratemaking are addressed in Part III. Part IV turns to the design considerations in which utility commissions have an interest. It emphasizes potential tradeoffs between consumer electricity rates and the overall efficiency of GHG regulation. Part V examines how state GHG policies may interact with a national system.

⁵ These data are from the U.S. Energy Information Administration, Emissions of Greenhouse Gases in the United States 2005, available at <http://www.eia.doe.gov/oiaf/1605/ggrpt/index.html>.

II. GHG Cap-and-Trade Policies and Compliance Responses

A. Cap-and-trade policies

1. Overview

Cap-and-trade policies can be understood as working in three steps:⁶

- 1) An overall cap on emissions is defined for a set of entities. In a cap-and-trade program for GHGs, the cap will most likely be defined in terms of CO₂ equivalents.⁷ The set of entities could be as limited as those in the electric generation sector, or as broad as all fossil fuel users plus major emitters of other GHGs like methane.⁸
- 2) The right to emit the quantity of emissions defined by the cap is translated into emissions allowances. The unit of allowances in a GHG cap-and-trade is likely to be one metric ton of CO₂. Depending on choices in program design, the responsible government agency allocates allowances to specified entities at no cost, sells the allowances to the affected entities or to other parties, or does a combination of allocation and sales. All GHGs emitted by the entities in the program must be accompanied by the surrender of an equal amount of allowances.
- 3) The allowances can be exchanged among any parties at any price mutually agreeable to buyers and sellers.

A cap-and-trade policy combines the certainty of a quantitative limit with the flexibility and economic efficiency of market decision-making. This basic design has worked well for sulfur dioxide and nitrogen oxide regulation in the United States, and has been central to quantity controls systems for CO₂ under the Kyoto Protocol, the European Union as a whole, and planned or implemented systems in the UK, Canada, and Australia.

⁶ There are many permutations and complications in these three steps, the most important of which for utilities are explained below. For a straightforward but more detailed explanation of the mechanics of cap-and-trade, see pages 1-3 of Ellerman and Joskow (2003), *Emissions Trading in the U.S.: Experience, Lessons and Considerations for Greenhouse Gases*, available at http://www.pewclimate.org/docUploads/emissions_trading.pdf.

⁷ Global warming potentials (GWPs) are used to compare the abilities of different greenhouse gases to trap heat in the atmosphere. Methane, for example, has a GWP over a hundred years of 23, meaning that one ton has the same effect as 23 tons of CO₂. A good overview of the methodology and full listing of GWPs can be found at <http://www.eia.doe.gov/oiaf/1605/gwp.html>.

⁸ CO₂ accounts for almost all of the direct GHG emissions of the electric industry. In this report we will use the terms CO₂ and GHG interchangeably in referring to electric industry emissions and to allowances.

A key metric used to discuss GHG limitation policies, both for cap-and-trade and tax policies, is the “carbon price” (see Box 2). In the context of a cap-and-trade system, the carbon price is the same as the allowance price – the value of the right to emit one metric ton of GHGs, expressed in terms of \$ per metric ton of CO₂ equivalent. All else being equal, more stringent caps mean higher carbon prices because they translate directly into an overall lower supply of CO₂ allowances. The higher the carbon price, the higher the cost of generating electricity.

Box 2: Allowance Trading and the Carbon Price

The term *carbon price* is frequently used synonymously with the price of allowances in a cap-and-trade system. Carbon price refers to the cost of emitting a unit of carbon dioxide, or more broadly any greenhouse gas converted to the equivalent effect on GHG concentration as carbon dioxide. A carbon price can be imposed through a tax or through a cap-and-trade system.

With a tax, a specific carbon price is imposed directly. A decision to tax GHGs at \$25 per t of CO₂ equivalent sets a carbon price of \$25 per t CO₂ equivalent. If one mwh of pulverized coal generation emits 0.9 tons of carbon dioxide, then a carbon price of \$25 would increase the cost of generating a mwh by $0.9 \text{ t CO}_2 / \text{mwh} * \$25 / \text{t CO}_2 = \$22.50$ per mwh. If one mwh of generation from natural gas emits 0.4 tons of carbon dioxide, then a carbon price of \$25 would increase the cost of generating a mwh by $0.4 \text{ t CO}_2 / \text{mwh} * \$25 / \text{t CO}_2 = \$10.00$ per mwh.

A cap-and-trade system sets a carbon price indirectly. The cap creates a scarcity of rights to emit GHGs, so people and institutions buy and sell those rights until an equilibrium price is reached. Tighter caps mean higher prices, *ceteris paribus*; less stringent caps mean lower prices. The allowance price set in the market becomes the carbon price, because every unit of GHG emitted must be covered by an allowance. If the price of allowances is \$25 per t CO₂ equivalent, then the cost of generating electricity with pulverized coal will increase by the same amount as in the tax example – each mwh of electricity will require 0.9 t of allowances, which have a value of \$22.50, and thus the cost of generation is increased by \$22.50.

Unlike a tax, a cap-and-trade system does not set a predictable and stable carbon price. Until the market establishes a price, there will be uncertainty as to what the price will be. As technology and economic conditions change, the price in the market can also change. Futures and options markets will provide tools to help manage this price uncertainty. Policy choices, including a “safety valve” (see Part II.A.2.g.4 below), and rules governing offsets and borrowing, also help to manage this uncertainty. In a new federal GHG cap-and-trade there will still unavoidably be substantial uncertainty until the system has been up and running for several years.

The carbon price is a useful summary metric for gauging the effect of policy on economic decisions that effect GHG emissions. Higher carbon prices mean the GHG-intensive products will be more expensive; they also mean that manufacturers and consumers have increased incentives to find ways of emitting fewer GHGs. Lower carbon prices send weaker signals for conservation, changes in the composition of energy, and technological innovation.

Because the carbon price is a key element in research that seeks to predict the effects of GHG policy on economic growth and well being, policy analysts and economists tend to talk as if it were a single price that covers the entire economy. This will be the case only if a tax or cap-and-trade does in fact cover all (or almost all) GHG emissions. A policy that treats electric generation differently than transportation, for example, would result in multiple carbon prices. Similarly, regional cap-and-trade policies not explicitly linked together will likely create different carbon prices in covered sectors between those regions.

2. Cap-and-trade design elements

The implications of a GHG cap-and-trade policy for utility regulators, utilities, and their customers depend critically on the details of the program. The most important elements of these policies are the stringency of the cap, the breadth of coverage, which GHGs are covered, the point of administration, allowance allocation, and a set of alternatives that manage uncertainty by providing additional compliance options. State utility regulators will be particularly affected by the way allowances are allocated. Each of these factors is discussed in this section.

a. Stringency of the cap

The cap determines the number of available allowances and therefore the quantitative limit on GHG emissions by covered sectors. The actual cap is a specific number of tons of GHGs, almost always expressed in terms of CO₂ equivalents. Caps tend to be set in reference to a historical level of emissions – for example, the current version of the McCain-Lieberman proposal sets the cap at 2004 emissions level in 2012 and at much lower 1990 levels in 2020. The Bingaman proposal sets its targets in terms of the GHG intensity of Gross Domestic Product (i.e., emissions per GDP), so that future targets will depend on economic growth as well as on base year emissions.

Most proposals contain caps that get progressively lower in future years, consistent with the overall goal of deeper cuts in GHGs over time to eventually stabilize concentrations in the atmosphere. Pushing the deeper cuts out in the future gives more time for the economy to adjust to GHG limitations and for new technologies to be developed.

b. Breadth of coverage

Any cap-and-trade passed in the U.S. is virtually certain to apply to the electric industry at a minimum. Some proposals limit the program to electricity production, while others include the transportation sector and large industrial sources. Still other policies attempt to encompass all sources of GHGs in the economy.

c. Point of administration

Point of administration is the choice of exactly which entities are formally regulated in a cap-and-trade system. These entities are the ones that must demonstrate that they hold enough allowance to cover their emissions, and will be held liable if their emissions exceed their allowance holdings.

Downstream systems require that the entities that emit GHGs into the atmosphere hold permits for those emissions. This approach is practical for utilities and large industrial sources, which can handle the administrative task of tracking emissions and allowances. The majority of these large emitters have continuous emissions monitors (CEMs) that measure CO₂ in addition to other air pollutants. However, it is both impractical and very expensive for vehicle operators, purchasers of home heating fuel, and other decentralized users of fossil fuels to participate in the allowance trading system. A variant of a downstream system for utilities is to require load serving

entities (LSEs) to hold allowances for all power that they sell – this system is discussed in detail in Part III.C.6 below.⁹

Upstream systems make use of the fact that the CO₂ content of coal, oil, and natural gas are very good predictors of the CO₂ released during combustion. An upstream system works by requiring businesses that introduce fossil fuel into the economy to cover the GHG content of those fuels with an emissions allowance. The scarcity imposed by the cap would be incorporated into fuel prices. This system would work for all fuel users, but would require adjustments for a few specialized cases (for example, carbon capture and storage by utilities would have to be credited to the utility itself – see Box 3).

Hybrid systems mix different levels of administration for different industries or fuel types. Some national cap-and-trade proposals cover electric generators and other large emitters at the point of emissions (downstream) and small emitters at the level of refineries and other key points in the fossil fuel distribution systems (upstream). They may cover the entire energy economy or exempt some sectors (for example, the bill sponsored by Senator Lieberman in the 110th Congress exempts fossil fuel used directly for home heating). Another proposed hybrid (found in the bill sponsored by Senator Bingaman in the 110th Congress) is to administer CO₂ emissions from coal downstream (at the point of combustion) but emissions from petroleum and gas upstream (at the point where they are first sold or imported by energy companies).

Box 3: Carbon Capture and Storage in a GHG Cap-and-Trade System

Carbon Capture and Storage (CCS) is a promising technology for low-GHG electric generation that has been demonstrated on a small scale, but has yet to be implemented on a commercial scale or proved to be economic at such a scale. CCS works by removing the CO₂ from fossil fuels – particularly coal -- during pre-combustion processing or after combustion. This box explains how CCS can be made compatible with different kinds of cap-and-trade administrative structures.

In a downstream system, where measurement of emissions takes place at each generation unit, accounting for CCS is straightforward. Assume that a coal burning plant in a downstream system is emitting 1,000 t of CO₂, for which it must surrender 1,000 t worth of allowances valued by the market at \$20 per allowance. If the company can implement CCS that removes and permanently sequesters 80% of its CO₂, it will only require 200 t of allowances. It will balance the cost of the CCS project against the \$16,000 it saves (800 t of allowances @ \$20 per t).

In an upstream system, where fossil fuel producers and importers must hold allowances for the GHG content of the fuels they sell, the price of fuel the generation owner buys will increase by \$20,000 as a result of the \$20 allowance price. In order to give the generation owner the correct incentives to implement CCS, the cap-and-trade system has to provide a mechanism providing allowances equal to the amount of CO₂ sequestered. In this example, if the generator can demonstrate that it has removed and permanently sequestered 800 t of CO₂, it should be granted 800 t of allowances by the cap-and-trade administrative structure. It would then sell these allowances for \$16,000 to fossil fuel producers or importers. The incentives remain the same as in the downstream case – the generator compares the cost of the CCS project with the \$16,000 that the project saves.

As long as generators can accurately measure the amount of carbon they capture and store, CCS can be accommodated with a cap-and-trade system under any administrative system.

⁹ See Box 5 for definitions and discussion of the meaning of load-serving entity, local distribution company, and vertically integrated utility as used in this report.

d. Which GHGs are covered

The major legislative proposals in the U.S. all follow the lead of the Kyoto Protocol in focusing on six gases – CO₂, methane, N₂O, hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulfur hexafluoride (SF₆). Methane is emitted from livestock operations, fossil fuel production, solid waste management, and other sources. Nitrous oxide comes predominantly from agricultural operations, with the combustion of fossil fuels by mobile sources being the second largest U.S. source. The other three gases are emitted in relatively small quantities from industrial processes, but have very high GWPs and therefore a significant effect on overall GHG concentrations.

CO₂ is not only the most quantitatively significant GHG, it is also the easiest and least expensive to measure and track. Although a cap-and-trade system will probably nominally cover all six gases, the major focus will be on CO₂ for both of these reasons.

e. Allowance allocation: overview

There are many different ways that allowances can be distributed to affected entities in a GHG cap-and-trade system. The allocation scheme chosen has a direct effect on the distributional consequences of a cap-and-trade program. As an example, consider an economy-wide GHG limit set at 2000 emissions levels – an estimated 6,242 million metric tons CO₂ equivalent. If allowance prices for this cap turn out to be \$25 per ton, then the total value of these allowances would be about \$156 billion per year. If the share of emissions generated by electric utilities in 2000 were to remain constant, then the allowances used by utilities in this example would be worth \$57 billion. The key point is that allowances are financial assets with a high degree of liquidity. There is an enormous amount of money at stake in the way allocation rules are determined, i.e., in who receives the \$57 billion in value.

There are two crucial issues in understanding how allowance allocation affects generators and consumers of electricity. The first issue is the quantity of allowances that the industry receives at no cost (as opposed to allowances that must be purchased at the market price). The second issue is the basis for allocating no-cost allowances to different entities in the industry.

(1) Allowance allocation: cost or no cost?

In a cap-and-trade system, the emissions of individual generators do not directly depend on the number of allowances that each receives. Generators will buy and sell allowances as needed as they adjust their operations in response to the price of allowances. This fact does not take away from the importance of how allowances are distributed – that decision has direct effects on the distribution of gains and losses imposed by the cap-and-trade system. The decision about which entities in the electric industry receive allowances without payment, and how many they receive, affects the latitude available to commissions in ratemaking (as explained in Parts III.C and III.D below).

A national cap-and-trade program could distribute allowances to the electric industry in a variety of ways. The industry could be allocated a percentage of allowances based on its historical contribution to total CO₂ emissions. It could also be allocated no allowances without cost; the

industry then would need to buy the allowances at market price, causing significantly more resources to comply with cap-and-trade requirements. The industry could receive any quantity of allowances in between these extremes.

There are also varied options for allocating allowances that are *not* given to the entities that emit CO₂ (including the electricity industry). One is direct government sales of allowances. This process is generally referred to as an auction, the idea being that the government will design a process where the price of allowances they sell is established through a market mechanism and not by simply setting a price. The federal government could use the auction proceeds as general revenue, or earmark them for specific purposes like alternative energy research. The other options involve giving allowances at no cost to other public sector institutions -- for example, state governments -- that would sell the allowances and use the receipts for designated purposes. From the standpoint of the electricity industry, the critical choice is the number of allowances it receives at no cost, and not whether other allowances are allocated through an auction or alternative process.

In the SO₂ trading program, the federal government allocated the bulk of allowances to generation owners at no cost, based on historical patterns of fuel input (with some special allocations for high emitters). Generation owners still faced significant expenditures to reduce their SO₂ use, and bought and sold allowances to match their emissions, but did not incur the large expenditures that would have been required to buy enough allowances to cover all of their SO₂ emissions.

Determination of allowance allocation to the electric industry is a key feature of the ongoing debate in congressional cap-and-trade proposals. A likely outcome is that some percentage of allowances will be allocated to the industry at no cost in the early years of the program; that percentage then will decline, possibly to zero, through pre-announced reductions over time. Both the initial quantity of no-cost allowances and the details of any phasing out are critically important features of policy design.

The key point here is that allowances are assets with significant market value. The way that they are allocated is not the most important design parameter for determining the overall level of GHG reduction or the efficiency of the system in terms of total costs to the U.S. economy. It is the most important parameter for determining how a GHG cap-and-trade system affects the profits of affected firms. As we will discuss in Part III below, it also has the potential to have significant effects on ratepayers through impacts on electricity prices for states whose prices are set by embedded-cost regulatory processes.

(2) How to allocate no-cost allowances – emissions or output

If allowances allocated at no cost to the electric generation industry, what criteria would determine the allocation? The two criteria most frequently discussed are emissions and output. Basing the allocation on emissions from a particular base year is an obvious choice; it is premised on the idea that any source's difficulty in complying will be closely related to the magnitude of their emissions. Allowances could also be allocated as a function of electricity output in a given base year; this approach would reward low-carbon sources like nuclear or hydropower at the expense of coal-fired generation.

One alternative to determining no-cost allocations using data from a historical base year is to allocate each year's allowances based on electricity output from some immediately previous period - a process called "updating" (See Box 4 for more detail). The more electricity a utility generates the more allowances it receives the next year. This approach causes utilities to invest more in GHG reduction so that they receive more allowances, which results in lower electricity prices (in markets where competition, rather than regulators, determine prices) and higher allowance prices. Because electricity output is higher and electricity prices are lower, this method tends to produce less conservation behavior by electricity consumers.¹⁰ Updating is popular with consumer advocates because it produces lower prices at the expense of utility shareholders. Economic studies find that it has higher overall costs than alternative allocation schemes because it fails to induce conservation behavior through the higher prices that are found under grandfathering¹¹ or auctions.

¹⁰ For a good discussion and an empirical examination of updating in the Regional Greenhouse Gas Initiative, see Burtraw, Kahn, and Palmer (2005), "CO2 Allowance Allocation in the Regional Greenhouse Gas Initiative and the Effect on Electricity Investors," Resources for the Future Discussion Paper 05-55.

¹¹ Grandfathering refers to allocations made without cost to the recipient and based on historical patterns of fuel use or generation.

Box 4 – Allocation of Allowances through Updating

Updating works by allocating allowances at no cost based on the most recent electricity output of generation units. It rewards generation owners that can produce the most electricity in the GHG-constrained system, and not those that have historically high levels of output or emissions (which is the case in varying versions of grandfathering allowances). Because the GHG cap-and-trade system makes it less expensive for lower-GHG generation technologies to increase output, updating tends to favor these sources.

Proposals for updating vary between limiting free allocation to GHG – emitting sources (primarily coal, natural gas, or petroleum generation), and including all sources that sell electricity through LDCs. In the latter case, all allowances earned by very low emitting sources are sold in the allowance market since those generators do not need them. These zero-emitting sources can include existing nuclear and hydropower generation as well as renewable energy sources like wind and geothermal. Including all generators in updating allocation increases the incentives for low-GHG generation. One point of view holds that nuclear and hydropower generation should not qualify for freely allocated allowances, since this existing generation has done nothing to change its GHG profile under the cap-and-trade system. One way to address this concern is to base the allocation formula on net increases in generation from a given source, rather than on absolute levels of generation.

Updating allocates the wealth embodied in no-cost allowances differently from grandfathering. Analysts and modelers have predicted an additional and somewhat surprising outcome: it results in lower electricity prices and lower overall economic efficiency than either grandfathering or auctioning allowances. The reason for this is the incentives generation owners face when deciding whether to increase output at the margin in a competitive environment. Companies compare the additional generation cost (including the cost of any additional allowances required) with the price they receive; they will choose not to produce the output if the costs exceed the price. With updating, there is an additional benefit of increasing output – a slightly higher share of the allowance pool allocated by updating. Generators take account of this additional benefit and will be willing to produce more electricity at any given electricity price because of it.

Since all generators face this same set of incentives, more electricity is produced than would otherwise be the case. This higher output translates into lower prices for consumers. Updating hurts rather than helps generators in the aggregate because they are competing with each other for the same fixed pool of allowances. For example, if they all increase generation an additional 10% in order to increase their allocation, then they will each receive the same number of allowances they would have if none of them had changed their output levels. So generator profits, and therefore the value of generator assets, are lower under updating. Because additional generation by fossil fuel generators will ordinarily require additional allowances, updating further disadvantages coal-fired generation relative to natural gas and even lower-GHG sources.

The fact that prices are lower under updating means that less price-driven reduction will take place by consumers. Because consumers forego more efficient reductions and generators take more expensive (in theory) GHG actions, the overall social costs are greater under updating than under other allocation methods. However, from the standpoint of some utility commissions there are definitely two attractive characteristics – lower consumer prices and increased incentives for low-

f. How to allocate no-cost allowances – generation owners, LSEs or LDCs

Any allowances allocated at no cost to the electric industry could go to the owners of generation or to LSEs. They could also go to local distribution companies (LDCs) in their role as institutions with an obligation to physically deliver electricity to end-users. The choice among these options has implications for electricity pricing and generator profits, implications elaborated in Part III below. Box 5 defines the differences among generation owners, LSEs, and LDCs as the terms are used in this report.

Box 5 -- Generation Owners, LSEs, LDCs, and Vertically Integrated Utilities

Terminology can be confusing in the ever-changing landscape of commission regulation of the generation, sale, and delivery of electricity. This box clarifies the way four important terms are used in this report: generation owner, load-serving entity (LSE), local distribution company (LDC), and vertically integrated utility. The functional distinction between these terms has implications for understanding the point of administration of a GHG cap-and-trade system, and also for the allocation of no-cost allowances.

The term “generation owner” is straightforward – it refers to the entity that legally owns the assets that produce electricity.

The LSE is the entity that has a contractual obligation to supply end use loads by selling kwh at retail. By definition, all electricity sold in the US passes through an LSE. LSEs can be generation owners themselves (i.e., vertically integrated companies), or they can purchase all the power they sell, or they can meet their load-serving obligation through a combination of their own generation and purchased power.

The LDC is the company that owns the wires over which electricity is delivered to consumers. LDCs deliver electricity and collect money from customers. LDCs are the entity whose pricing behavior is universally under direct price regulation by state utility commissions, regardless of a state’s regulatory structure.

All electricity produced and sold in the U.S. has a generation owner, is sold by an LSE, and is distributed by an LDC. These three functions can be filled by one, two, or three separate entities in different configurations of electricity generation, sale, and delivery. A vertically integrated utility is likely to be a generation owner, an LSE, and an LDC. An LSE could own some or all of the generation necessary to serve its load, but have its power delivered by a separate LDC. An LSE could own no generation but also serve as the LDC for the power that it purchases and sells to consumers. All three functions – generation owner, LSE, and LDC – can be performed by different entities.

The term “vertically integrated utility” is used in this report to refer to companies that combine all three functions – the ownership of generation, the obligation to supply end use loads, and the physical delivery of electricity to consumers.

This report makes a sharp distinction between embedded cost ratemaking applicable to generation costs, and market pricing applicable to generation costs. Embedded cost ratemaking for generation cost, in the context of retail electricity, can take place only where the same entity is the generation owner, the LSE, and the LDC. This combination of functions is necessary for state commissions to possess the authority to apply embedded cost ratemaking to generation costs.

The distinction between LSE and LDC is important in this report because it has implications for the effects of allowance allocation schemes. When allowances are allocated to LDCs, commissions have direct control over the way the value of allowances affect retail price, LDC profits, and GHG mitigation investments. When allowances are allocated to LSEs or generation owners, commissions have control only in cases where those entities are also LDCs.

g. Additional compliance options

Cap-and-trade systems are designed to achieve compliance primarily through the choices and actions of regulated emitters. GHG cap-and-trade policy proposals contain other compliance options for two reasons. First, in case compliance proves to be more expensive than predicted, these options help to keep the economic costs of the program in check. Second, offset mechanisms provide incentives that help to develop ways of reducing GHG concentrations outside of the entities covered by the cap-and-trade.

(1) Offsets

The idea behind offsets is that actions taken voluntarily outside the cap-and-trade system can reduce GHG concentrations. These reductions can substitute for reductions made by the regulated entities, and should therefore create the equivalent quantity of allowances that can be used for compliance. As an example, consider the case of carbon sequestration in the forestry and agricultural sectors.¹² If a farmer takes action that increases the amount of CO₂ stored in his soils by one metric ton, this could qualify as an offset. An allowance would be created and given to the farmer, who would then be able to sell it to a business covered by the cap-and-trade. This concept increases the supply of allowances, and thus decreases the allowance price, without increasing net contributions to total GHG concentrations.

Carbon sequestration in U.S. soils and biomass is expected to be a significant source of offsets. Reductions from GHG-emitting sectors not covered by a cap-and-trade system are also potentially significant. For example, if transportation were exempted from a mandatory national policy, cities could create offsets by investing in mass transit or other GHG-reducing activities. A third important potential source of offsets is GHG reductions in developing countries, both in sequestration and emissions-reduction activities.

There are a number of theoretical and pragmatic difficulties with offsets, and it is beyond the scope of this report to explore them.¹³ Also, the rules for determining offsets are important – the stricter the standards of measurement and verification that offsets actually fully reduce GHGs by specified amounts, the more expensive they will be. The broader the menu of actions available for producing offsets, the more plentiful and cheaper they will be. Plentiful and cheap offsets increase the supply of allowances, decrease their cost, and thus make compliance less expensive for utilities.

(2) Links with Other Cap-and-Trade Systems

There has been interest in making it possible to comply with a U.S. cap-and-trade for GHGs through the purchase of allowances from other national and regional cap-and-trade systems -- the European trading system and the (on-again and currently off-again) Canadian system among them. In such an arrangement U.S. allowances also could be purchased and used for compliance elsewhere. The effect on the U.S. of linking systems together depends on the design parameters and trading rules of each system – particularly the relative stringency of GHG caps in the different systems. For the time being, the linking concept is probably at most a secondary concern in U.S. system design.

¹² Carbon sequestration is the storage of CO₂ in soils, biomass, or any other location that prevents it from entering the atmosphere. No-till agriculture and afforestation are two widely practiced means of sequestration. For a good overview of issues concerning this subject see EPA's website at <http://www.epa.gov/sequestration/index.html>

¹³ A useful overview is provided in Murray, Sohngen, and Ross (2006), "Economic consequences of consideration of permanence, leakage and additionality for soil carbon sequestration projects," *Climatic Change* (2007) 80:127–143.

(3) Banking and borrowing allowances

Banking is the ability to retain unused allowances to cover emissions in subsequent years. Most policy proposals allow banking, some unlimited and others with limitations on the quantity or percentage of allowances that can be banked. Banking has been a feature of other cap-and-trade programs and is widely regarded as having been a positive factor in explaining the success of those programs.

Borrowing refers to mechanisms through which future allocations of allowances can be used in the present. The effect is to allow more emissions in the present, thus reducing the cost and difficulty of compliance. Some proposals do not allow borrowing until a pre-determined trigger – for example, a specific allowance price in the market – occurs. Borrowing is included in proposals only when strict limits on amount of borrowing are imposed, and is strongly opposed by some because it limits incentives to reduce GHGs in the present, while creating pressure for less stringent caps in the future.

(4) Safety valve

A safety valve (also called a “cost cap”) works by allowing the cap on emissions to be relaxed (i.e., raised) when compliance costs rise above a pre-determined level. For example, assume that a cap-and-trade system includes a safety valve set at \$25 per ton of CO₂. If the emissions cap is met and the allowance price in the market is \$20, then the safety valve has no effect. If, however, the marginal cost of reducing GHGs – and thus the allowance price -- begins to rise above \$25 per t, then under a safety cap regime the government would sell additional allowances to any interested purchaser for \$25 per t. Since anyone could buy these allowances, no one would ever pay more than \$25 in the allowance market. Each allowance sold by the government would increase the amount of emissions by which the cap-and-trade limit is exceeded. Note that the incentive to reduce GHGs at the margin remains at \$25 per t under the safety valve – additional emissions are not free to emitters.

The positive effect of the safety valve is that it limits downside economic risk in cases where GHG reduction proves more costly than expected, while maintaining GHG reduction incentives. It also provides additional certainty on energy costs for those planning new or changed economic activities. The downside is that, *ceteris paribus*, it weakens incentives to invest in reduction technologies and allows the GHG target – the cap – to be exceeded, reducing the environmental effect of the cap-and-trade program. A safety valve also makes linking different cap-and-trade systems together more difficult, and can create problems with excessive banking of allowances under some conditions. The safety valve has been a highly controversial design element in policy negotiations at the international and national levels. Its inclusion in a U.S. cap-and-trade policy is strongly supported by some interested parties, but is generally opposed by the environmental NGO community.

B. GHG-reduction options in the production and use of electricity

Complying with GHG limitations for electricity generation can be achieved through any combination of the measures discussed next.

1. Compliance mechanisms that could increase the cost of generating electricity¹⁴

a. Increased generation efficiency

Engineering and operational improvements that increase the amount of electricity from the same amount of fuel allow each allowance to cover more generation. Investments in generation efficiency that might not be economic at the margin without a cap-and-trade system may make sense when the allowance price is considered. While increases in the efficiency of existing generation may make important contributions to GHG reduction, it will not be enough for the current generation technology – particularly coal-fired generation – to meet even moderately aggressive GHG reduction goals. Such reductions will require a combination of new technologies, greater use of existing low GHG sources, and conservation by end users.

b. Low or zero-emitting generation technologies

Generation can be switched to increased use of existing units that have relative low CO₂ emissions, or new generation capacity can be built that uses nuclear, wind, geothermal, solar, hydroelectric, or biomass as a source of fuel or heat. Coal-fired power plants can co-fire biomass. Generation that switches from coal to natural gas also results in a reduction of CO₂ emissions per unit of electricity.

c. Carbon capture and storage

A high percentage of CO₂ produced by fossil fuels can be captured during or after combustion and then stored so that it never enters the Earth's atmosphere. As long as it stays stored (in underground or undersea geological formations or as a solid), the CO₂ does not have an effect on atmospheric GHG concentrations and therefore does not require an allowance in a cap-and-trade system. The technology for capturing CO₂ is less expensive and better proven for Integrated Gasification Combined Cycle coal generation, which is currently more expensive per unit of capacity than traditional pulverized coal plants. The technologies for long-term storage are still in testing and pilot phases, and are not in widespread use around the world except in circumstances where the CO₂ is used directly for enhanced oil recovery by petroleum producers. CCS is significant

¹⁴ For background on particular generation technologies, their physical characteristics and their costs, see McGarvey, et al. (2007), *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria*, NRRI Report 07-03 available at www.nrri.org.

because it provides an avenue for continued use of coal while still meeting GHG reduction goals.¹⁵ See Box 3 for a discussion of the technical challenges of including CCS in a cap-and-trade system.

d. Allowance purchases and sales

Generation owners¹⁶ can purchase allowances, allowing them to expand their CO₂ emissions to meet the demand for electricity with their current technologies. Generation units that face the highest cost and greatest difficulty of reducing or limiting increases in GHG emissions will tend to follow this course as part of their compliance strategy. Since overall emissions are capped, the more electric generators follow this strategy, the higher the carbon price will go and the more incentive all electric generators will experience to use other compliance mechanisms. Generation owners can also sell allowances when they have lower-cost compliance options.

The allowance price will always represent a common compliance cost at the margin – regulated entities can adjust their allowance holdings to cover their emissions. The allowance market will serve as a mechanism by which marginal compliance costs will tend to be equalized among GHG-emitting generation units. The price of allowances may not be constant, however, and there are risks in basing compliance decisions on the purchase or sale of allowances at any given expected price. These risks can be mitigated by the use of futures markets in allowances.

2. Compliance mechanisms that work by reducing electricity demand

a. Price-induced end user conservation

End users (residential, commercial, and industrial) will decrease electricity use in response to increases in the price of electricity that result from the cap-and-trade systems. They will do so both through changes in technology (more efficient heating and cooling systems, for example) and through behavioral changes (for example, changing their thermostat settings).

b. Demand-side management activities

Consumers of electricity do not take advantage of every cost-effective way to reduce their electricity use. In addition, it may be less costly for utilities to invest in their customers' conservation than to invest in new generation or generation improvements. The electricity sector has a history of demand-side management programs where energy efficient technologies are fully or partially paid for by LDCs or LSEs. These technologies may include the services of specialists in

¹⁵ A good overview of the technology and economics of CCS can be found at http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm.

¹⁶ In an upstream or LDC-administered system, the generation units will not directly purchase allowances, but the economic incentives of the cap-and-trade system will tend to guide generation owners toward the same choices as when they buy and sell allowances. Details and examples on how this works can be found in Parts III.C and III.D of this report below.

conservation that locate, operate, purchase, or manage the installation of energy efficient technologies. In the context of a GHG cap-and-trade system, demand-side management may represent a low-cost way of reducing GHG emissions through reducing generation. Box 6 provides additional detail on the relationship between price-driven conservation and demand-side management institutions.

Box 6: Energy Conservation -- Economic Signals or Institutions

Electricity conservation – reduced usage by consumers – is found by both research and anecdote to be able to provide a substantial share of low-cost GHG reduction. The role of the public sector in general, and utility commissions in particular, in realizing these reductions depends on underlying assumptions about consumer behavior.

The point of view espoused by many economists is that price is the most important driver of conservation. Higher electricity prices cause consumers to change behavior and alter their selection of capital – for example, both turn down their thermostats and buy more efficient air conditioners. Without the price signal, consumers will not make these adjustments.

The position taken by advocates of demand-side management (DSM) actions is that cost-effective conservation activities are underperformed when based solely on market signals, and therefore institutional responses to directly perform or encourage conservation are a good investment. Retrofitting insulation to housing and promoting and subsidizing energy efficient appliances are examples at the residential level. Efficient lighting appliances and control systems for commercial applications are another example.

Commissions do not need to exclusively support price incentives or DSM. Increased prices have some effect in encouraging conservation, and well-designed and managed DSM programs can decrease energy use cost-effectively. There are three key questions for utility commissions: Should pricing decisions directly consider conservation incentives? Should revenue raised through electricity sales be devoted to DSM activities? How should DSM activities be targeted and funded?

The first two questions are taken up in Section 3 of this report. Overall, if LDCs can achieve electricity conservation (and therefore GHG reduction) more effectively than consumers, then there is a good case for using revenue from electricity sales for DSM activities. If DSM activities are less effective than the price signal in producing conservation and associated GHG reductions, then ratepayers will be footing the bill for inefficient GHG reductions.

The third question – how to target and structure DSM activities – is about both efficiency and equity. The efficiency component is to design and implement programs that achieve GHG reductions at the lowest administrative and operational cost. The equity question is who receives the benefit of DSM expenditures. For example, if a DSM program fully or partially installs or pays for higher efficiency lighting or air conditioners, the owner of the business or residence gets a direct financial benefit from lower electric bills while receiving Commission-approved funds to fund their purchase and/or retrofit. Commissions have an interest in making sure the financial benefits conferred by these programs are targeted in line with their goals for equitable treatment of ratepayers.

III. Cap-and-Trade, Regulatory Decision-Making, and End-Use Pricing

A. Overview and introduction

In this section we develop examples to demonstrate how allowance prices combine with program design choices, market structure, and ratemaking technique to determine end-user electricity pricing. In doing so, we will make a strong distinction between two different generation pricing structures.

The first, **embedded cost ratemaking**, refers to situations where an LDC owns the generation, and its state regulators set retail rates using traditional embedded cost techniques: establishing an annual revenue requirement to reflect prudent expenses plus return on the rate base invested in prudent capital expenditures, allocated among customer categories and then divided by the expected units of sale to arrive at an average cost rate charged uniformly within each customer class. (For purposes of simplicity we will ignore the fixed charge component of electricity rates, which ordinarily appears as a per-customer charge or a demand charge.)

The second, **market pricing**, covers situations where generation prices are determined in some kind of market mechanism, including through long-term contracts, spot markets, or by the marginal provider in a power market administered by an institution such as a regional transmission organization. Commission regulation (at the federal level) here takes the form of ensuring that competitive forces are sufficient to discipline prices to just and reasonable levels, rather than setting prices for individual sellers (as is the case in embedded cost ratemaking); at the state level regulation consists of determining whether the LDC's purchasing decisions were prudent.

Although there are more subtleties among the utility regulatory environments in the U.S., this distinction warrants attention because it is critical to how a cap-and-trade program design affects electricity prices, GHG compliance choices, and the overall efficiency of the cap-and-trade system.

Note that in most states, there is a regulated utility whose generation costs are affected by both embedded cost pricing and market pricing. With the exception of LDCs that have divested all their generation, LDCs tend to use a mix of self-owned generation and purchased power to serve their retail load, with the purchased power often coming from a wholesale market whose prices are set through a market mechanism.

In this Part III we focus on costs incurred by generation owners in a one-year period. This time-limited focus abstracts from the complexities of generation owner and commission decisions that are made to achieve objectives over a long time period. In following the examples and discussion presented here, it is best to think of each period's costs as representing that period's share of the net present value of long run costs that are fully known (unless specifically noted) to both generation owners and commissioners.

We first address commission decisions in the context of embedded cost ratemaking. Commissions make decisions about approval of costs incurred and when those costs can be recovered, about whether expenditures should be rate based (thus recovered over time, with the

unrecovered amounts qualifying for a rate of return) or expensed (thus recovered currently), and whether to share the risks and benefits of cost overages and cost underages, relative to cost levels assumed in establishing the revenue requirement, between electricity consumers and utility shareholders. We then turn to how cap-and-trade system plays out for generation owners who are subject to competition. Based on this analysis, we then address options for commission issue advocacy in national and regional GHG cap-and-trade program design. We evaluate outcomes relative to three criteria of interest to regulators and to the nation as a whole.

The first and foremost of these criteria is the effect on electricity prices. Commissions are obligated to ensure that rates are just and reasonable. The way that GHG policies affect these rates is a central concern to regulators.

The second criterion is the way that utility regulation and program design interact to influence the compliance activities that utilities choose to meet GHG reduction goals, and how customers react to those utility decisions. Policy, economic, and regulatory choices will determine the mix of generation efficiency improvements, new capital expenditures, new fuel mixes, consumer efficiency actions, and allowance purchases and sales.

These concerns interact with a third criterion -- the overall efficiency of the GHG reduction system. While the focus of utility regulators is on pricing and generation choices, regulators operate in a general policy environment where the nation is best served by a GHG reduction framework that is equitable, transparent, and efficient in meeting politically-determined environmental goals at the lowest feasible cost.

If minimizing electricity prices for consumers were the only concern of commission regulation, then the weakest possible program and the lowest possible allowance price would serve their interests best. Commissions serve the public interest, and may also wish to define their interests as achieving an efficient GHG reduction and control system in a way that keeps their ratepayers from paying an inequitable part of the burden, managing new risks from a GHG control system, and helping to achieve an overall cost-effective reduction of GHGs.

B. Approval of technology under allowance price uncertainty

1. Introduction

In this section we consider the problem of technology choice under price uncertainty – uncertainty over the price CO2 allowances. Price uncertainty describes the situation up until the time that the specifics of a national cap-and-trade program are determined by legislation and/or regulation. It is also likely to pertain to the period of time between a cap-and-trade system’s passage and its actual implementation, and even into the first few years of the program, because even once program design is known there will be uncertainty about the actual allowance price. Once a cap-and-trade program has been running for a few years there is likely to be significantly better information about allowance prices; plus there will be tools available (e.g., robust futures markets) to manage price risk. In thinking about this example, it is probably most useful to think about technology choice in the current environment – a federal cap-and-trade is likely, but the timing and program details are highly uncertain. This Part III.B applies to decisions made under embedded cost

ratemaking only – generation decisions made under market pricing are not subject to commission review and approval.

2. Basis of the example

As an example, consider a vertically integrated utility regulated under embedded cost ratemaking technique that has determined it needs enough new generation capacity to produce 100 mwh per year, and that this capacity must come on line in 2014. In order to meet this timeline, the utility must choose a technology and begin construction by 2008. Assume that the utility is choosing between a pulverized coal plant, a natural gas plant, or an integrated gasification combined cycle coal (IGCC) plant with the option of adding CCS technology. The characteristics of the technologies in the example are given in Table 1.¹⁷ Note that IGCC technology has one set of costs, and implementing carbon capture and storage adds additional costs while reducing CO2 emissions further. The line designated as “Lowest IGCC” in Table 1 represents the costs of IGCC with CCS implemented only when its addition reduces overall costs (which happens at higher allowance prices). The example is based on allowance price uncertainty – at the time of the utility’s technology decision, allowance prices of \$10 per t, \$25 per t, and \$40 per t are considered by the commission to each be equally likely (i.e., to each have a 1/3 probability) of being the allowance price in 2014 and afterward.¹⁸

¹⁷ In all examples in this Part III of this report, including this one, the costs and other characteristics of technologies **are not meant to indicate the actual costs of construction or operation**. These costs in this example are chosen to illustrate the mechanics of technology choice under allowance price uncertainty.

¹⁸ This example assumes that the number of allowances that the vertically integrated utility receives at no cost is not dependent on its choice of technology.

**Table 1:
Example of Technology Choice under Allowance Price Uncertainty**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Technology	Average Generation Cost per mwh	CO2 emissions per mwh	Cost per mwh @\$10/t CO2	Cost per mwh @\$25/t CO2	Cost per mwh @\$40/t CO2	Average Cost
(1)	Pulverized Coal	\$50.00	0.95	\$60	\$74	\$88	\$74
(2)	IGCC	\$55.00	0.76	\$63	\$74	\$85	\$74
(3)	IGCC w/ CCS	\$75.00	0.1	\$76	\$78	\$79	\$78
(4)	Lowest IGCC	\$110@\$10CO2/ \$125@\$25 and \$40 CO2		\$63	\$74	\$79	\$72
(5)	Gas	\$62.50	0.47	\$67	\$74	\$81	\$74

Calculation Details

Line (4) reports the results for the lowest-cost choice from lines (2) and (3)

Column (4) = column (2) + [column (3) * \$10]

Column (5) = column (2) + [column (3) * \$25]

Column (6) = column (2) + [column (3) * \$40]

Column (7) = [Column (4) + Column (5) + Column (6)] / 3

The cost per mwh is calculated with the following equation:

$$\text{Cost per mwh} = \text{Average Generation Cost per mwh} + [\text{tons of emissions per mwh} * \text{allowance price per ton of emissions}]$$

And the average cost (column (7)) is calculated as the average when all three allowance prices (\$10, \$25, and \$40 per ton of CO2) are equally likely.

3. Generation cost as a function of allowance price

In our example, the vertically integrated utility (in this section, sometimes referred to as the LDC) approaches a state commission for advance approval of its generation decision, before a national GHG policy has been passed. The eventual price of CO₂ allowances is uncertain for policy, economic and technology reasons. The policy reasons are the unknown design parameters – a less stringent cap and/or an expansive offset policy will tend to produce a low allowance price, while a stricter cap and demanding offset rules will tend to produce a higher price. The economic uncertainty is the unknown element of how flexible economic activity will be as GHG limits come into being – if conservation and increased efficiency prove relatively easy to achieve, the price will tend to be low; if difficult, allowance prices will be higher. If generation owners and end users successfully innovate and deploy new technology to achieve significant GHG reductions, allowance prices will be lower than if technological progress is slow.

In this situation the commission will have to evaluate proposed capital expenditure decisions with uncertainty about the allowance price. If the allowance price turns out to be \$10 per t, then pulverized coal will be the lowest-cost technology. (This can be seen by its having the lowest cost, \$59.50 per mwh, in column (4) of Table 1.) If the allowance price ended up at \$40 per t, then IGCC with CCS will be cheapest. (It has the lowest cost in column (6) of Table 1.) At the middle allowance price of \$25 per t, pulverized coal, gas, and IGCC without CCS all have similar prices (column (5)). The average cost is lowest for the IGCC plant with the option of adding CCS (line (4)).

One implication of this example is that any of these choices can turn out to be “wrong” once program details are in place and allowance prices are observed. If commissioners wish to second-guess generation owners’ assessment of construction costs, they must base this on their own expectation of allowance prices.

A second implication is that commissioners should base their decisions on how generation costs are affected across an expected range of allowance prices. They must decide whether they care about choosing the technology with the expected lowest cost, or whether they are more concerned about guarding against very high costs. In our example above, pulverized coal has a competitive average cost but a 1/3 chance of very high costs.

A third implication is that modularity has significant advantages when future allowance prices are uncertain. The line of the table marked “Lowest IGCC” chooses to implement CCS or not, depending on how high the allowance price turns out to be. This approach results in the lowest expected generation costs of any of the options because the generator can wait to invest in GHG-reduction technology until allowance prices are actually known (or at least known with greater certainty).

4. Ex-post reviews of prudence under price uncertainty

The issues are similar for ex-post reviews of whether expenses incurred should be recovered from consumers or be disallowed as imprudent. The question is whether the LDC acted prudently at the time its decision was made. Given that there is inherent and unavoidable uncertainty in the price

of allowances, simply observing that the course of action taken was not the lowest-cost option is not enough – the question is whether it was a reasonable¹⁹ course of action at the time.

5. Price uncertainty and the “build or buy” decision

The treatment of risk arising from allowance price uncertainty can affect the vertically integrated utility’s choice between (a) building and owning new generation capacity under embedded cost regulation and (b) buying power from wholesale generation sellers in a market pricing environment. If vertically integrated utilities believe that they are bearing too much risk because their decisions may be ruled imprudent, the strategy of purchasing power will become more attractive.

If a vertically integrated utility believes that it will be able to pass its generation and compliance costs through to ratepayers, then it will tend to build its own generation because it can then add to its rate base and earn returns on those investments. If, however, there is a risk of its decisions being found to be imprudent and therefore not allowable in its revenue requirement, it will have to balance those potential losses against the increased profits.

We illustrate this situation with a specific example. Assume that allowance price expectations are identical to those in Table 1 – an equal probability that the price will be \$10, \$25, and \$40 per t. Say that the option with the lowest expected cost for new generation in a particular market is pulverized coal technology. Assume that the construction of a plant that sells 500,000 mwh per year yields an annual return on rate base of \$2 million.

If the vertically integrated utility believes that it will be able to include its allowance costs in its revenue requirement and thereby recover them from ratepayers, then it will build the plant itself in order to earn the \$2 million. However, if it believes that any costs above \$25 per allowance will be disallowed because other generation options are cheaper at that price, but that all savings for allowance costs below \$25 will be passed on to ratepayers rather than kept by the utility, then its decision criteria change. In this latter scenario (i.e., expected disallowance of allowance cost above \$25), if all three prices in the example are equally likely, then expected profit is

$$\$2 \text{ million} - [1/3 * 475,000 * \$15] = -\$375,000$$

where \$2 million is the expected return on the rate base, 1/3 is the probability prices will be above \$25, 475,000 is the number of allowances required for 500,000 hours of generation (based on the assumption of .95 t COS per mwh from Table 1), and \$15 is the amount of each allowance cost that

¹⁹ The term "reasonable" is used to mean that imposition of the costs on ratepayers is appropriate. Some jurisdictions believe that if a cost is prudent then its inclusion in rates is appropriate. Other jurisdictions apply, in addition to "prudence," a "used and useful" test. This report does not distinguish between those two concepts because its purpose is not to advise on the ultimate question of cost recovery but instead to explain how different generation choices affect different regulatory decisions.

the vertically integrated utility must absorb if the allowance price is \$40. In this situation the company loses money on average.

With this unprofitable outcome in mind, the vertically integrated utility will consider buying power on the wholesale market from a generation owner that builds its own pulverized coal plant. In that situation the utility does not receive the \$2 million in return on equity for its shareholders. However, it no longer bears any risk for high allowance prices; it simply passes through the price charged by the independent generator to ratepayers.

Note that this bias against embedded cost generation results from asymmetric regulatory treatment of risk and reward assumed in this example. If the vertically integrated utility were liable for increased allowance costs above \$25 but got to keep additional profits for allowance prices below \$25, then the expected profits from low allowance prices would balance out expected losses from high allowance prices.

The same potential bias against vertically integrated utility construction applies when there is uncertainty about the costs and effectiveness of GHG reduction technologies. For example, if carbon capture and storage turns out to be more expensive than anticipated and vertically integrated utilities cannot recover those unanticipated costs, but must pass through savings when costs are less than expected, then purchased power will become more attractive to these utilities relative to building generation under embedded cost regulation.

Commissions could address this asymmetry by setting a target allowance price on which vertically integrated utilities should make decisions, and then symmetrically making shareholders fully or partially liable for deviations in the allowance prices that the utilities actually have to pay. They could also flow through both positive and negative deviations from an assumed allowance price to end-users via pass-through clauses. The key point is that asymmetric regulatory treatment of allowance price or compliance cost risk can have a significant effect in making purchased power more attractive than building their own generation.

6. Summary: Approval decisions under allowance price uncertainty

Utility commissions face difficult decisions under ordinary circumstances in determining when generation construction decisions are prudent and efficient, and how to allocate risk between shareholders and ratepayers. When commissions retain the ability, after construction is complete, to disallow costs that are excessive, they have the ability to protect ratepayers from bad decisions or poor performance by vertically integrated generation owners. This section has demonstrated that such decisions can also affect the attractiveness to utility generation owners of investing in new and uncertain technologies. Policies which place a price on GHG emissions make commissioners' decisions about approval more complex by making GHG reduction costs and efficiency, relative to an unknown allowance price, another essential piece of determining prudence and risk.

C. The effect of cap-and-trade design and allowance price on embedded cost ratemaking

In Part III.B above, we analyzed how allowance price uncertainty affects generation cost and technology choice. We now turn to ratemaking under embedded cost regulation when allowance prices are known with certainty. Our goals are to show explicitly how GHG allowances affect ratemaking, and to examine how program design parameters and regulatory decisions affect rates. We first take up the case of embedded cost ratemaking -- where generation is owned by a vertically integrated, load-serving retail utility not subject to competition -- since this is where utility commissions have the most direct decision-making responsibility. We will consider decisions under alternative arrangements for allowance allocation and administrative structure. In Part III.D we then examine the effect of these same alternatives on generation owned by wholesale sellers who are subject to market pricing.

1. Embedded cost ratemaking, no-cost allocation

In this section we assume that a vertically integrated generation owner operating under embedded cost ratemaking must make decisions to comply with a GHG cap-and-trade program. This generation owner also expects an expansion in electricity consumption.²⁰ This example is intended to have costs that are plausibly in line with existing utility economics, but they are intended for illustration only and have been kept deliberately simple for that reason. All capital and depreciation costs are expressed as a levelized one-period component of long run costs. For example, the capital cost of \$20,000 for coal at an output of 1,000 mwh per year means that the generator will be able to fully pay for the cost of the plant and associated debt by applying that identical \$20,000 per year over the entire life of the plant.

A conventional coal plant that has an average production cost of \$50 per mwh at an output of 1,000 mwh per year and a high degree of capacity utilization is assumed.²¹ We posit that 40% of total costs at this output level are capital costs that are in the rate base and are fixed, and remain in the rate base even if output declines. The other 60% of the costs are variable in the medium run, and decline linearly as output declines.

The basis of the example is that the LDC has to meet an additional 50 mwh per year of consumption. Meeting the additional consumption requirement through conventional coal generation necessitates an expansion of both capital and operating costs. An alternative to new coal generation capital is demand-side management (DSM), which we assume reduces the consumption requirement by 50 mwh at a cost of \$1,500 (\$30 per mwh). We choose these very low costs for DSM here not to indicate that it is actually the cheapest option in general, but because it allows us to demonstrate more clearly the ramifications of how DSM works under embedded cost ratemaking. A second alternative is some form of zero carbon generation (ZCG – this could be wind, hydropower, geothermal, nuclear, etc.) that can be built for \$3,000 for 50 mwh per time period (as for coal, this cost is levelized so that an identical payment in every time period fully covers costs over the lifetime

²⁰ We base the example on an expansion of consumption so that we can highlight the critical role of fixed capital costs in compliance decisions under embedded cost ratemaking.

²¹ The assumption of high capacity utilization is made to highlight the role of capital costs in the rate base in determining the cost of alternative compliance options.

of the equipment) and has zero variable cost. The example is constructed so that coal-fired generation is cheaper than ZCG when GHGs are not capped, but its average cost (including capital costs) exceeds ZCG at a carbon price of \$25 per t CO₂.

Note that we are **not** taking account of reductions in electricity demand that result from increased electricity prices in this analysis. Reductions in demand would mean lower electricity consumption and a smaller increase in generation. This will be discussed in Part III.F.

Table 2 gives the basics of our example. Expenses that qualify to be included in the rate base earn a return of 10%, and other expenses are passed through to consumers.

Table 2
Technology Options and Costs for Compliance Example

Initial Electricity Output	1,000 mwh
Initial (Unregulated) Emissions	800 t CO ₂
CO ₂ emissions (t) per mwh of coal-fired generation	0.8
Capital Costs for 1,000 mwh of coal-fired generation	\$20,000
Variable Costs for 1,000 mwh of coal-fired generation	\$30,000
Additional Consumption to be met	50 mwh
Capital cost of additional 50 mwh of coal-fired generation	\$1,000
Variable cost of additional 50 mwh of coal-fired generation	\$1,500
Cost of 50 mwh of Zero Carbon Generation (ZCG)	\$3,000
Cost of 50 mwh of Demand Side Management (DSM)	\$1,500
Price of CO ₂ Allowances	\$25 / t

a. Downstream Administration

A downstream cap-and-trade program requires that the utility generation owner hold allowances (allowances are denominated so that each allowance is for one ton of emissions) to cover all CO₂ emissions. Assume that the generation owner receives – at no cost – 800 allowances,²² and that the price in the allowance market is \$25. The results of alternative compliance options and regulatory decisions are given in Table 3, along with the details of the calculations.

As an illustration of how ratemaking is done in this example, consider a utility decision to meet the new consumption requirement by adding additional coal-fired capacity (line 2 of Table 3), compared with the costs if there were no cap-and-trade system in effect (line 1 of Table 3). The utility adds \$1,000 worth of annual capital costs that are included in the rate base, and \$1,500 of operating costs that are passed through to end users. In addition, the utility must purchase allowances to cover the 40 t of CO₂ emissions that result from the additional 50 mwh of electricity production from coal. These allowances cost \$1,000, as indicated in column (9). The generator

²² An allocation of 800 t in this example is roughly consistent with a cap set at current emissions and generator allocations based on historical emissions levels. The 800 t is the emissions level assumed before the cap-and-trade takes effect and before the generator must meet the additional 50 mwh of consumption.

receives a 10% return (column (4)) on expenses in the rate base, which are computed as the sum of expenses in column (1) and any allowances in column (9) that are included in the rate base (as indicated by column (10)). Column (3) indicates that no resources are spent on demand-side management in this option. Column (5) sums columns (1) - (4) and column (9) to show the total costs of generating electricity to meet the consumption requirement. This sum is the revenue requirement that must be recovered from end-users. Dividing the revenue requirement by generation quantity (column (6)) gives the end user price (column (7)). The only differences between lines (1) and (2) are the \$1,000 spent for allowances, and the additional return on the rate base from those allowances that is included in line (2). The additional costs created by allowance purchases are responsible for a price of \$53.05 per mwh relative to a price \$52.00 per mwh if there were no cap-and-trade policy in effect.

Table 3.
Example Results for Compliance Options under Regulated Generation:
No-cost Allowance Allocation and Downstream Administration

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Compliance Option	Levelized Capital cost	Variable Cost	DSM Cost	Return on Rate Base	Revenue Requirement	Generation (mwh)	Price per mwh	CO2 emissions (t)	Cost of Allowance Transactions	Purchased Allowances in Rate Base?
(1)	No GHG Program – New Coal Generation	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840		
(2)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$2,200	\$55,700	1050	\$53.05	840	\$1,000	yes
(3)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$2,100	\$55,600	1050	\$52.95	840	\$1,000	no
(4)	DSM 50	\$20,000	\$30,000	\$1,500	\$2,000	\$53,500	1000	\$53.50	800	\$0	
(5)	ZCG 50	\$23,000	\$30,000	\$0	\$2,300	\$55,300	1050	\$52.67	800	\$0	
(6)	ZCG 100 (ratepayers get proceeds from sold allowances)	\$26,000	\$28,500	\$0	\$2,600	\$56,100	1050	\$53.43	760	(\$1,000)	

Calculation Details

The generation owner receives 800 t of allowances at no cost for all options (Lines (1) – (6))
Column (1) = the levelized capital costs allowed in the rate base
Column (2) = the variable costs of generation passed on to ratepayers
Column (4) = 10% * [Column (1) + value of allowances allowed in the rate base (indicated in column (10))]
Column (5) = Sum of Columns (1) to (4) minus Column (9)
Column (6) = electricity generated as specified by the technology choice
Column (7) = Column (5) / Column (6)
Column (8) = quantity of coal-fired generation (mwh) * tons of CO2 per mwh
Column (9) = Column (8) - the quantity of freely allocated allowances
Column (10) indicates whether allowances acquired for cash are included in the rate base

b. Allowance price effects on compliance option choice

In Part III.B we examined prudent choice under price uncertainty. Now we look at pricing in more detail in a situation where the allowance price is known. The option that has the lowest overall price increase for consumers is reliance on ZCG for the additional output. The importance of this outcome for our example is the role of the cap-and-trade program and the allowance price. Line (1) shows that without a cap-and-trade, coal generation would be the option with the lowest end user price, while with allowances prices at \$25 per t CO₂ coal becomes a more expensive option than ZCG: the price in column (7) is higher for new coal generation in lines (2) and (3) than for ZCG in line (5). Note that the allowance price causes ZCG to become a lower-priced option compared to expanding coal generation, even though the generation owner chooses to neither buy nor sell any allowances when meeting additional load through ZCG (the emissions of 800 t exactly match the utility's allocation of no-cost allowances). Commission oversight of utility decision-making will need to be based on explicit consideration of allowance requirements to determine whether generators have made prudent decisions.

The pricing of electricity under DSM illustrates a potential divergence between minimizing end-user prices and efficient GHG reduction. We constructed this example so that DSM was the lowest cost option for meeting additional consumption requirements – half the cost of ZCG. Table 3 shows that DSM has the lowest revenue requirement of any of the options. This revenue must be recovered from a smaller amount of electricity sales (1,000 mwh instead of 1,050 mwh), and so results in the highest price (\$53.50 in Table 3). What does not show up in the calculation is that the higher price should be balanced against the savings in energy costs realized by end users who participate in the DSM program. Commissions that value DSM as a GHG reduction strategy need to recognize that its potential efficiency may be accompanied by larger price increases than other options under embedded cost ratemaking.

While the imposition of a cap-and-trade program in this hypothetical makes ZCG less costly than adding coal-fired capacity, the example also demonstrates that building additional ZCG in order to reduce emissions still further – allowing the generator to then sell allowances – raises overall costs. This can be seen by comparing the price and revenue requirements for line (6) – 100 t of new ZCG – with the other options in Table (3). The revenue requirement of \$56,100 in column (5) of line (6) is the highest for any option even though the utility generation owner receives \$1,000 for the allowances it can now sell. The reason for this result is that existing capital costs are still recovered in the pricing formula, so reducing generation from coal saves only variable costs (including CO₂ allowance costs). This result demonstrates that under embedded cost ratemaking the financial hurdle will be higher – allowance prices must be higher or ZCG carbon generation less costly – for achieving GHG reductions through reduced generation from existing plants than for choosing low or zero carbon alternatives when new construction is taking place.

c. How to apportion gains and losses from allowance transactions between ratepayers and shareholders

When ratepayers receive the entire proceeds from sold allowances, generation owners lack the incentive to aggressively seek out low-cost compliance options that free up allowances to be sold. When shareholders receive the proceeds from sold allowances that the generation unit receives at no cost, then the generation owner will have incentives to invest too much in GHG reduction in order to profit from selling allowances.

If generation owners were only interested in meeting an obligation to minimize generation costs, this scenario would not present a problem – they would choose to make the GHG-reduction investment. Similarly, if commissions have full knowledge of all available compliance options, their costs, and their effectiveness in reducing GHG emissions, then they might not allow recovery of generation expenses that resulted from a failure to make this investment. Commission oversight could mandate that generation owners make the choice that meets the commission’s regulatory goals.

In circumstances where novel technologies are not fully transparent to commission regulation and utility generation owners are focused on maximizing shareholder returns, then this tension between efficient GHG reduction and profitability can affect utility choices. Suppose that there were some truly innovative way to reduce emissions – for example, by some new process that allowed some post-combustion CO₂ to be sequestered at relatively low cost. If such a choice cost \$2,000 in operating expenses but allowed the generation owner to sell \$5,000 worth of allowances, then it would lower the revenue requirement by \$3,000, and also be an efficient way of reducing GHGs and lower the revenue requirement and price. However, under this regulatory treatment the generation owner has little incentive to seek out such reductions if all allowance proceeds go toward reducing consumer price, because it leaves shareholder returns unchanged.

This same problem of aligning generation owner interest in maximizing return on the rate base with a commission’s legal obligation to ensure reasonable, low-cost power and efficient pollution reduction has been a question of regulatory interest in the SO₂ trading program, and was analyzed at length and with great insight in NRRI’s analysis of the SO₂ market.²³ If all gains and losses from the sale of no-cost allowances go to ratepayers, generation owners who can over-comply at low cost will lack the incentives to do so and free up allowances for sale. Utility generation owners that can comply at lower cost by buying allowances may prefer more expensive and capital-intensive methods of reducing emissions to increase shareholder returns.

Suppose that rather than being passed through to consumers, the utility generation owner is allowed to retain some portion of the allowance sale proceeds as profit. If it were allowed to keep 25%, then the revenue requirement would be reduced by \$1,750 (\$5,000 - \$1,250 worth of

²³ Rose, et. al. (1992), *Public Utility Commission Implementation of the Clean Air Act's Allowance Trading Program*, The National Regulatory Research Institute, NRRI-92-6, Columbus, Ohio. <http://nrri.org/pubs/electricity/96-15.pdf>

allowance proceeds less \$2,000 worth of expenses). The resulting end user price would still be lower than in the absence of the investment, and the generation owner would have an incentive to engage in the project. Giving generation owners some share of the gains on allowance sales also gives them incentives to find lower costs compliance strategies. However, this solution has the problem that any share of allowance sales in shareholder returns makes such sales too attractive, and gives generation owners incentives to invest in overly expensive generation capital to free up allowances to sell. Such actions could increase overall costs and end user prices.

Commissions should be aware that if generation owners don't receive the benefits from selling allowances, they might forgo efficient GHG reduction investments. If generation owners do keep the proceeds from selling allowances, they may make inefficient reduction investments. The treatment of no-cost allowances in commission oversight of generation expenses makes regulation more complex and information-intensive than when generation owners' returns do not depend directly on these transactions.

2. Embedded cost ratemaking, downstream administration, auctioned allowances

We now turn to pricing where allowances are all auctioned, instead of allocated to generation owners without cost. Table 4 examines the exact same compliance options as in Table 3, but is based on a situation where utility generation owners must purchase the allowances to cover all CO₂ emissions. Line (2) of Table 4 shows the results for when the utility generation owner builds coal-fired capacity to produce an additional 50 mwh per year. The difference caused by having to pay for all allowances shows up in Column (9). The generation emits the same 840 t of CO₂ as it did in Table 3 (1050 mwh * 0.8 t CO₂ per mwh), but now its cost of allowance transactions is \$21,000 (840 t of allowances * \$25 per t), while in the example for Table 3 it is purchasing only 40 allowances. This increase in expenses shows up in a much higher revenue requirement for all compliance options in Table 4.

The option that results in the lowest end user price is still 50 mwh of ZCG (as evidenced by its having the lowest computed cost in column (7) of Table 4). The most striking difference from the previous section is that the increases in end user prices for all options are higher because regulators set rates to allow generation owners to pass through the full cost of allowances. The identical compliance responses that brought about prices in the range of \$52.67 - \$55.00 now cause prices of \$71.71 - \$75.00 per mwh. This difference occurs because ratepayers are paying the cost of all the allowances needed for compliance.

Table 4.
Example Results for Compliance Options under Regulated Generation:
Auctioned Allowances and Downstream Administration

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Compliance Option	Levelized Capital cost	Variable Cost	DSM Cost	Return on Rate Base	Revenue Requirement	Generation (mwh)	price per mWh	CO2 emissions (t)	Cost of Allowance Transactions	Purchased Allowances in Rate Base?
(1)	No GHG Program – New Coal Generation	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840		---
(2)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$4,200	\$77,700	1050	\$74.00	840	\$21,000	yes
(3)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$2,100	\$75,600	1050	\$72.00	840	\$21,000	no
(4)	DSM 50	\$20,000	\$30,000	\$1,500	\$2,000	\$73,500	1000	\$73.50	800	\$20,000	no
(5)	ZCG 50	\$23,000	\$30,000	\$0	\$2,300	\$75,300	1050	\$71.71	800	\$20,000	no
(6)	ZCG 100 (ratepayers get proceeds from sold allowances)	\$26,000	\$28,500	\$0	\$2,600	\$76,100	1050	\$72.48	760	\$19,000	no

Calculation Details

The generation owner receives zero allowances at no cost for all options (Lines (1) – (6))

Column (1) = the levelized capital costs allowed in the rate base

Column (2) = the variable costs of generation passed on to ratepayers

Column (4) = 10% * [Column (1) + value of allowances allowed in the rate base (indicated in column (10))]

Column (5) = Sum of Columns (1) to (4) minus Column (9)

Column (6) = electricity generated as specified by the technology choice

Column (7) = Column (5) / Column (6)

Column (8) = quantity of coal-fired generation (mwh) * tons of CO2 per mwh

Column (9) = Column (8) - the quantity of freely allocated allowances

Column (10) indicates whether allowances acquired for cash are included in the rate base

When generation owners receive no-cost allowances, there are regulatory complexities raised in how allowances sales and purchases are treated (Part III.C.1.c). When all emissions must be covered by purchased allowances, as in this example, all allowances must initially be purchased and can be treated the same way as any other expense in commission review. Utility use of allowances relative to other compliance options is transparent to commissions.

This example also highlights that the question of whether allowances are (a) capital expenditures (and therefore included in the rate base), or (b) expenses to be passed through directly to consumers, matters more when larger quantities of allowances are purchased. Table 4 shows that when compliance relies entirely on allowance purchases, inclusion of full allowance value in the rate base increases price by \$2 per mwh more than when allowance costs are passed through as expenses; whereas when allowances are allocated at no cost the difference is only \$0.10 (the differences between the price in lines (2) and (3) in Table 3). This is a simplification – commissions are likely to consider only some portion of allowance purchases related to the use of shareholder equity as eligible for inclusion in the rate base if they are to be included at all. The point of emphasis is that larger allowance purchases magnify the effect of commission decisions about how purchased allowances enter the rate base under any possible formula.

As an alternative to auctions, allowances could be allocated to organizations that fund alternative energy research, states and cities, and/or consumer organizations (see Part II.A.2.e.i). These organizations would realize income by selling the allowances to generation owners in a downstream system. The effect on pricing and decision-making would be identical to that of auctioned allowances as described in this subsection – generation owners would still need to pay the full cost of the allowances needed to cover their emissions, and pass those costs along via the revenue requirement.

3. Embedded cost ratemaking, downstream administration, allocation to LDCs

Part III.C.1 addressed the allocation of no-cost allowances to vertically integrated generation owners who are subject to embedded cost ratemaking. We now turn to allocation at no cost to LDCs.²⁴ If allowances are allocated to LDCs in a system with downstream administration, then generation owners would buy allowances from LDCs (as well as from other sources). The cost of these allowances would be included in the price at which the LDC purchases power. The LDC could use the receipts from allowance sales to reduce its revenue requirement and the resulting retail price of electricity. The LDC, under Commission regulation, could also use the receipts for other purposes.

Table 5 demonstrates how this works for the lowest-cost compliance option of 50 t of new ZCG when the LDC receives 800 t of allowances. Line (3) shows that the generation owner buys 800 t of allowances to comply and faces the same total costs as under auctioned allowances (line (2) of Table 5). In this situation, the LDC must pay \$75,300 to the generation owner

²⁴ We focus on allocation to LDCs and not to LSEs because the LDC is the entity that is subject to state commission price regulation under all circumstances.

(column (5)). The difference is that it sells its 800 t of allowances for \$20,000 (column (6)) and applies these receipts to its revenue requirement (line (3), column (7)). The resulting price that meets this revenue requirement -- \$52.67 per mwh -- is identical to the price when the generation owner received the 800 no-cost allowances (as in line (1) of Table 5).

**Table 5: Comparison of Effects of Allocation Methods and Administration Level:
Example of 50 tons of new Zero-Carbon Generation**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	<u>Policy</u>	Levelized Capital cost	Variable Cost	Return on Rate base	Cost of (receipts from) Allowance Transactions (generation owner)	Revenue Requirement for Generation	Allowance Costs (Receipts) for LDC entering into column (7)	Revenue Requirement for LDC	End user price per mwh
	Downstream								
(1)	No-cost allocation to generation owners	\$23,000	\$30,000	\$2,300	\$0	\$55,300	\$0	\$55,300	\$52.67
(2)	Auctioned	\$23,000	\$30,000	\$2,300	\$20,000	\$75,300	\$0	\$75,300	\$71.71
(3)	No-cost allocation to LDC	\$23,000	\$30,000	\$2,300	\$20,000	\$75,300	(\$20,000)	\$55,300	\$52.67
(4)	No-cost allocation to LDC - 75% of sales to reduce rev. requirement	\$23,000	\$30,000	\$2,300	\$20,000	\$75,300	(\$15,000)	\$60,300	\$57.43
	Upstream								
(5)	No-cost allocation to generation owners	\$23,000	\$50,000	\$2,300	(\$20,000)	\$55,300	\$0	\$55,300	\$52.67
(6)	Auctioned	\$23,000	\$50,000	\$2,300	\$0	\$75,300	\$0	\$75,300	\$71.71
(7)	No-cost allocation to LDC	\$23,000	\$50,000	\$2,300	\$0	\$75,300	(\$20,000)	\$55,300	\$52.67
	LSE Administration								
(8)	No-cost allocation to generation owners	\$23,000	\$30,000	\$2,300	(\$20,000)	\$35,300	\$20,000	\$55,300	\$52.67
(9)	Auctioned	\$23,000	\$30,000	\$2,300	\$0	\$55,300	\$20,000	\$75,300	\$71.71
(10)	No-cost allocation to LDC	\$23,000	\$30,000	\$2,300	\$0	\$55,300	\$0	\$55,300	\$52.67

Calculation Details

Lines (1) – (10) all refer to the identical generation and compliance actions, and have identical CO2 emissions of 800 t and identical electricity production of 1,050 mwh.

Column (1) = the levelized capital costs allowed in the rate base

Column (2) = the variable costs of generation passed on to ratepayers, including fuel price increases in upstream systems

Column (4) = The value of allowances bought or (sold) by the generation owner

Column (5) = Sum of Columns (1) to (4)

Column (6) = The value of allowances bought or (sold) by the LDC

Column (7) = Column (5) + Column (6)

Column (8) = Column (7) divided by 1,050 mwh of generation

To the extent that the LDC did not use all of the proceeds of allowance sales to directly reduce the revenue requirement, prices would be higher. Line (4) of Table 5 demonstrates pricing when 75% of the value of 800 t of no cost allowances is applied to reduce the revenue requirement and 25% are designated for other purposes. Column (6) shows that \$15,000 goes to offset the payment made to the generation owner (as opposed to \$20,000 in line (3) when all allowance receipts are so applied). The resulting revenue requirement and price (columns (7) and (8)) are higher in line (4) than line (3) of Table 5. This demonstrates one of the important decisions facing commissioners in a federal cap-and-trade program – the determination of how the value of allocated allowances should be apportioned between limiting consumer price increases and other uses.

Load-based allocation and upstream allocation have similar advantages relative to downstream allocation – they make utility generation owners’ decisions toward compliance under embedded cost ratemaking much more transparent to regulators, especially when utility generation owners may have incentives not to take the lowest-cost course of action. They also enable a more symmetric treatment of generation under embedded cost ratemaking and market pricing (see Part III.E).

4. Partial allocation of no-cost allowances to the electricity industry

We have examined the situation when allowances are allocated to the electricity industry at no cost, and when the industry must purchase all of its allowances. It is possible and even likely that allocation will be mixed, at least initially, with some allowances going at no cost to existing emitters, and some auctioned or allocated to third parties who would sell them into the system. In this mixed case, state commissions would retain influence only over the share of allowances allocated to LDCs or to generation owners that are vertically integrated utilities. Table 6 demonstrates what happens for the example in this subsection when 40% of allowances are allocated at no cost to generation owners and 60% must be purchased. The difference can be seen in column (9), the cost of allowance transactions, where each option shows a cost that is higher than when 800 allowances are received at no cost (as in Table 3) but lower than when 100% of allowances must be purchased (Table 4). The end user prices that result from partial allocation under embedded cost ratemaking (column (7) of Table 6) end up about 40% of the way between those in Table 3 (no-cost allocation) and Table 4 (100% auction). The higher the percentage of allowances that is allocated to the electric industry at no cost, the more state commissions have the ability to cushion end users from price increases.

Table 6.
Example Results for Compliance Options Under Embedded Cost Ratemaking:
Partial No-cost Allowance Allocation and Downstream Administration

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Compliance Option	Levelized Capital cost	Variable Cost	DSM Cost	Return on Rate Base	Revenue Requirement	Generation (mwh)	price per mwh	CO2 emissions (t)	Cost of Allowance Transactions	Purchased Allowances in Rate Base?
(1)	No GHG Program – New Coal Generation	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840	---	---
(2)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$800	\$66,300	1050	\$63.14	840	\$13,000	yes
(3)	New Coal Generation - Buy Allowances	\$21,000	\$31,500	\$0	\$2,100	\$67,600	1050	\$64.38	840	\$13,000	no
(4)	DSM 50	\$20,000	\$30,000	\$1,500	\$2,000	\$65,500	1000	\$65.50	800	\$12,000	no
(5)	ZCG 50	\$23,000	\$30,000	\$0	\$2,300	\$67,300	1050	\$64.10	800	\$12,000	no
(6)	ZCG 100 (ratepayers get proceeds from sold allowances)	\$26,000	\$28,500	\$0	\$2,600	\$68,100	1050	\$64.86	760	\$11,000	no

Calculation Details

The generation owner receives 320 t of allowances at no cost for all options (Lines (1) – (6))
Column (1) = the levelized capital costs allowed in the ratebase
Column (2) = the variable costs of generation passed on to ratepayers
Column (4) = 10% * [Column (1) + value of allowances allowed in the ratebase (indicated in column (10))]
Column (5) = Sum of Columns (1) to (4) minus Column (9)
Column (6) = electricity generated as specified by the technology choice
Column (7) = Column (5) / Column (6)
Column (8) = quantity of coal-fired generation (mwh) * tons of CO2 per mwh
Column (9) = Column (8) - the quantity of freely allocated allowances
Column (10) indicates whether allowances acquired for cash are included in the ratebase

5. Upstream administration, embedded cost ratemaking

In a cap-and-trade system with upstream administration, the price of the fuel that generation owners purchase will include the cost of allowances necessary to cover the fuel's GHG content. Table 7 displays results for upstream administration and no-cost allocation to generation owners. (We assume the generation owner receives 800 no-cost allowances, as in Table 3.) The price of the coal necessary to generate one mwh of electricity will rise by \$20 (based on our assumption of .8 t CO₂ per mwh of coal generation and \$25 per CO₂ allowance). Column (10) of Table 7 gives the additional cost of fuel for each generation option, and this increase is reflected in column (2) in larger variable costs. Generation owners receive \$20,000 in revenue from selling their 800 no-cost allowances (column (9)). In Table 7, these revenues are applied to reduce the revenue requirement computed in column (5). End-user pricing is identical to the results in Table 3 for downstream administration. The revenues from the sale of allowances balance the higher cost of fuel from the upstream cap-and-trade.

Table 7.
Example Results for Compliance Options Under Embedded Cost Ratemaking:
No-cost Allowance Allocation to Generation Owners and Upstream Administration

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Compliance Option	Levelized Capital cost	Variable Cost	DSM Cost	Return on Rate Base	Revenue Requirement	Generation (mwh)	price per mwh	CO2 emissions (t)	Cost of Allowance Transactions	Increased Fuel Costs
(1)	No GHG Program – New Coal Generation	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840		
(2)	New Coal Generation - Buy Allowances	\$21,000	\$52,500	\$0	\$2,100	\$55,600	1050	\$52.95	840	(20,000.00)	\$21,000
(3)	DSM 50	\$20,000	\$50,000	\$1,500	\$2,000	\$53,500	1000	\$53.50	800	(20,000.00)	\$20,000
(4)	ZCG 50	\$23,000	\$50,000	\$0	\$2,300	\$55,300	1050	\$52.67	800	(20,000.00)	\$20,000
(5)	ZCG 100 (ratepayers get proceeds from sold allowances)	\$26,000	\$47,500	\$0	\$2,600	\$56,100	1050	\$53.43	760	(20,000.00)	\$19,000

Calculation Details

The generation owner receives 800 t of allowances at no cost for all options (Lines (1) – (6))
Column (1) = the levelized capital costs allowed in the ratebase
Column (2) = the variable costs of generation passed on to ratepayers
Column (4) = Column (1) * 10%
Column (5) = Sum of Columns (1) to (4) minus Column (9)
Column (6) = electricity generated as specified by the technology choice
Column (7) = Column (5) / Column (6)
Column (8) = quantity of coal-fired generation (mwh) * tons of CO2 per mwh
Column (9) = Column (8) - the quantity of freely allocated allowances
Column (10) indicates the additional money paid for fuel as a result of the (already included in column (2))

Table 5 demonstrates directly (using the example of compliance through 50 t of ZCG generation) that the end-user pricing results depend on allocation choices and not on whether the system is administered upstream or downstream. In line (6), the electric industry receives no allowances and so the full price increase of fuel is passed onto consumers. In line (7) the LDC receives 800 t of allowances, sells those allowances to the companies regulated by the upstream system, and applies the receipts to reducing the revenue requirement. Lines (5) – (7) give identical pricing results to the downstream results in lines (1) – (3). One difference is that regulatory decision-making is simplified. The entities under commission regulation in an upstream system have no direct responsibility to limit GHG emissions, so any allowances that they are allocated serve as financial assets and not as a means of compliance with the cap-and-trade system. Commission oversight of utility generation decisions will be entirely separate from the treatment of the proceeds from allowance sales. Upstream administration creates a more transparent environment for commissions to evaluate the prudence of generation and GHG reduction choices.

6. Embedded cost ratemaking—administration through LSEs

A cap-and-trade policy can also be administered at the level of LSEs.²⁵ Allowances would be held, bought, and sold by load-serving entities, which would have to match the CO₂ in the electricity they sell to customers with the number of allowances they possess. We will demonstrate how this system works in the context of our ongoing example, then discuss advantages and disadvantages of this kind of administration.

Table 8 shows how pricing works when an LDC must hold allowances to cover the emissions for the electricity it buys from generation owners and sells to end users. In this case, we assume that the LDC is allocated 800 t of allowances. The LDC receives electricity from a generation unit that is priced by embedded cost ratemaking. Columns (1) – (7) of Table 8 show the generation unit's costs and pricing, which are unaffected by the GHG cap-and-trade system. Note that the lowest-priced option is coal-fired generation at \$52.00 per mwh and not ZCG at 52.67 (column (7)).

²⁵ A cap-and-trade system could technically be administered through LDCs, but such a system has not been seriously proposed. Such a system would share all of the complexity of LSE administration and increase the management burdens on those LDCs which are not part of vertically integrated utilities.

Table 8.

**Example Results for Compliance Options Under Embedded Cost Ratemaking:
Administration through LSEs and No-Cost Allowance Allocation through LDCs**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Compliance Option	Levelized Capital cost	Variable Cost	DSM Cost	Return on Rate Base	Revenue Requirement for Generation Owner	Generation (mwh)	Generation Owner price per mwh	CO2 Emissions (t)	Cost of Allowance Transactions for LDC	Revenue Requirement for LDC	End user price per mwh
(1)	No GHG Program – New Coal Generation	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840	\$0	\$54,600	\$52.00
(2)	New Coal Generation – Buy Allowances	\$21,000	\$31,500	\$0	\$2,100	\$54,600	1050	\$52.00	840	\$1,000	\$55,600	\$52.95
(3)	DSM 50	\$20,000	\$30,000	\$1,500	\$2,000	\$53,500	1000	\$53.50	800	\$0	\$53,500	\$53.50
(4)	ZCG 50	\$23,000	\$30,000	\$0	\$2,300	\$55,300	1050	\$52.67	800	\$0	\$55,300	\$52.67
(5)	ZCG 100	\$26,000	\$28,500	\$0	\$2,600	\$57,100	1050	\$54.38	760	(\$1,000)	\$56,100	\$53.43

Calculation Details

The LDC receives 800 t of allowances at no cost for all options (Lines (1) – (5))

Column (1) = the levelized capital costs allowed in the rate base

Column (2) = the variable costs of generation passed on to ratepayers

Column (4) = [Column (1) + value of allowances allowed in the rate base (indicated in column (10))] * 10%

Column (5) = Sum of Columns (1) to (4)

Column (6) = electricity generated as specified by the technology choice

Column (7) = Column (5) divided by Column (6)

Column (8) = quantity of coal-fired generation * .8 tons of CO2 / Mwh

Column (9) = (Column (8) – 800)* \$25

Column (10) = Column (5) divided by Column (9)

Column (11) = Column (10) divided by column (6)

Columns (8) – (11) of Table 8 show how pricing works when LDCs must meet an obligation to hold allowances to cover CO₂ emissions. Column (9) shows the cost of allowances needed to comply under each generation option, and Column (10) adds this amount to the revenue paid to the generation unit to compute the LDC’s revenue requirement. Column (11) divides this revenue requirement by the generation delivered to end users to compute the end user price. Column (11) of Table 8 shows that allowance costs make coal-fired generation more costly for end users than ZCG, even though it is less costly to generate. An LDC acting under commission regulation would act prudently here by buying more expensive electricity from a generation unit because of the savings in allowance costs.

Table 8 also demonstrates that LDCs could produce revenue by choosing electric power that has lower CO₂ emissions than their allocated quantity of no-cost allowances. Line (5) shows that 100 mwh of ZCG allows the LDC to buy 1,050 mwh of electricity that is responsible for 760 t of CO₂. This action frees up 40 t of allowances that the LDC can sell, producing \$1,000 in revenue for the LDC (column (9)). Column (11) shows that this is not the lowest-priced option given this particular set of costs, but this example serves to demonstrate that LDCs have the ability to produce revenue from no-cost allowances when they can find generation sources that have low GHG emissions.

Table 5 demonstrates – again using the example of 50 t of ZCG as the lowest-cost compliance option -- that the results for analogous allocation mechanisms are the same for administration through LDCs as for downstream and upstream administration for the same number of no-cost allowances.²⁶ This result illustrates the general point that the choice of administrative structure makes a difference in ratemaking formulas only when they affect the way that the revenues and costs from allowance transactions are divided between ratepayers and shareholders.

a. Advantages and disadvantages of LSE-based administration²⁷

Advocates of LSE-based administration find that this system is superior in its ability to encourage and contract for renewable energy generation and demand side management programs. LSEs attempting to minimize their costs of providing electricity can comprehensively and aggressively evaluate their options and encourage GHG-minimizing construction and operation of electric generation. In evaluating this claim, it is important to distinguish between economic signals and institutional abilities. The economic signals are in theory equal between upstream and load-based administration (as demonstrated in Table 5). The crux of the matter for commissions is the extent to which LSEs are spurred by allowance transactions -- and not by price – in seeking out and contracting for low-GHG generation and effective end user conservation.

The downside of administering a cap-and-trade at the LSE level is that administration is more complex than either downstream systems or upstream systems. This is because LSEs must be able to exactly track the CO₂ emissions associated with the electricity they buy, but are dependent on the

²⁶ The only difference is the situation covered in Table 3, line (2) when new allowance purchases are included in the rate base. Under LSE and upstream administration this option is not relevant.

²⁷ Subsection III.C.3 discussed the advantages to the *allocation of allowances* to LDCs. Here we discuss the purported advantages and disadvantages of *administration* at the level of LSEs.

generation units for emissions measurement. The system therefore requires generation units to measure and accurately report their CO₂ emissions for particular batches of power, even though they will have no legal responsibility to control those emissions. LSEs will have to keep track of the emissions associated with all of these separate purchases. An additional complication is that if LSEs buy power from pools, like those managed by independent system operators (ISOs) or regional transmission organizations (RTOs), it may be very difficult to track the emissions associated with any single purchase. The administrative and practical difficulties of measurement and tracking present a disadvantage relative to systems administered either at the level of generation units or fully upstream.

D. The effects of allowance allocation and price on end user pricing and compliance decisions: market pricing

Generation owners sell power to LSEs and LDCs under a wide variety of pricing arrangements different from the ratemaking process discussed in Part III.C. What these alternatives have in common is that the transaction price is based on some kind of market relationship -- negotiation and voluntary agreement between the generation owner and the LSE or LDC, or organized price setting mechanism such as the spot market, or an ISO- or RTO-administered power exchange. This difference has two implications for the way that generation owners under market pricing will operate in a GHG cap-and-trade system: price will be strongly influenced by generation owners' marginal costs, not their average costs; and state commissions have no legal authority to prescribe how generation owners buy, sell, and use the value of allowances (whether purchased or received at no cost). These two differences can cause significant divergence in pricing between the market pricing and embedded cost ratemaking segments of the market.

1. Marginal cost pricing for end users

Prices determined through voluntary agreements in markets tend to be set at the marginal cost of providing electricity.²⁸ This is in sharp contrast to pricing under embedded cost ratemaking, where average costs determine price. Market pricing based on marginal cost is the norm in some regions of the U.S., and makes up part of electricity supply in states that also supply electricity under embedded cost ratemaking.

When a cap-and-trade system is imposed, the cost of producing the most expensive unit of electricity that will find a buyer will include the cost of allowances to cover CO₂ emissions. Even when allowances are allocated at no cost, the recipients of those allowances have the option of selling them for cash and generating less electricity if that will produce higher profits. Generation sources that produce more GHG-intensive electricity will experience larger increases in marginal cost than generation sources that are less GHG-intensive. The resulting price of electricity under market pricing regimes will reflect both the marginal cost of generation and the marginal cost of GHG allowances.

The price that generation owners receive will therefore depend on the nature of consumption needs and the comparative advantage of different fuel sources and technologies in producing electricity under GHG constraints. The key fact for our discussion in this subsection is that the imposition of a cap-and-

²⁸ See, for example, Burtraw, Palmer, and Kahn, pp. 6-7, for a contrast of the RGGI region's pricing at marginal cost and other regions that price at average cost.

trade will increase the price for all electricity sold under market pricing by an amount that reflects the cost of allowances in generation. We base our specific example on the generation technology from the example in Part III.C, and assume that this is the technology that sets the price in the market. In this example, the market price for electricity is \$50 per mwh before the imposition of the cap-and-trade, reflecting the levelized capital and operating costs of producing a mwh of electricity from new coal-fired generation consistent with our example in Part III.C (Tables 2- 9). We assume this type of generation continues to set the market price under the cap-and-trade system.²⁹ The marginal cost of one mwh of electricity now becomes \$70 per mwh -- \$50 per mwh for generation and \$20 (0.8 t CO2 per mwh * \$25 per t CO2) for allowances to cover each mwh's CO2 emissions. We use \$70 per t as the market price of electricity throughout this subsection.

2. Market pricing—downstream administration

We assume that the generation owner with the same characteristics as listed in Table 2 has a chance to provide an additional 50 mwh per year in a market pricing arrangement at a price of \$70 per mwh. This generation owner chooses the lowest cost option available, which is to provide electricity with ZCG at a levelized cost of \$60 per mwh to produce this additional 50 mwh. Generation owners not under embedded cost ratemaking will have no incentive to invest in DSM, since they could achieve the same result at lower cost simply by reducing generation.

a. No-cost allocation to generation owners

If the generation owner receives 800 t of allowance allocated at no cost, it chooses to build 50 t of ZCG to maximize its profits. However, the price of electricity rises to \$70 per mwh for all 1,050 mwh of generation due to the impositions of a cap-and-trade with \$25 allowances. The profits of the generation owner increase as indicated in column (8), line (1) of Table 9. The increase in profits is because the generation owner receives the higher price caused by the cap-and-trade system's impact on market price (column (7)), but does not incur additional expenses for the 1,000 mwh of electricity covered by no-cost allowances. This increase is commonly referred to as a windfall profit³⁰ – the generation owner receives a higher price without any additional expense incurred.

²⁹ This assumption is somewhat arbitrary – the marginal cost producer under a cap-and-trade program could be using any kind of generation technology. It illustrates the likely outcome that the cost of allowances for a marginal unit of generation incurred by the dominant technology will tend to be a good estimate of the market electricity price under a cap-and-trade program. The salient point is that market prices will reflect the marginal cost of allowances independent of the way that allowances are allocated.

³⁰ Our example overstates the amount of the windfall profit because there will be some reduction in electricity consumption from the increase in price. Empirical estimates of the resulting reduction in profits find it to be less than 20%. See Goulder and Bovenberg (2001), “Neutralizing the Adverse Industry Impacts of CO2 Abatement Policies: What Does It Cost?” in C. Carraro and G. Metcalf, eds., *Behavioral and Distributional Effects of Environmental Policies*, University of Chicago Press; and Smith and Ross (2002), “Allowance Allocation: Who Wins and Loses Under a Carbon Dioxide Control Program?” Center for Clean Air Policy, http://www.ccap.org/pdf/ccap_cra_report.pdf.

Table 9.
Example Results for Market Pricing and Downstream Administration: Generation Owner Profits and End User Pricing

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Allowance Allocation	Action by Generator	Cost of 1,000 mwh of Coal-fired generation	Cost of 50 mwh of ZCG Generation	Cost of Allowance Transactions	Total Costs	Price for Generation Owner (per mwh)	Profit for Generation Owner	Allowance Value Applied by LDC to End User Price	Price for End User (per mwh)
(1)	Allocation to Generators (800 t)	add 50 mwh ZCG @ \$3,000	\$50,000	\$3,000	\$0	\$53,000	\$70	\$20,500	\$0	\$70.00
(2)	Generators pay for all allowances	add 50 mwh ZCG @ \$3,000 and buy 800 t of allowances	\$50,000	\$3,000	\$20,000	\$73,000	\$70	\$500	\$0	\$70.00
(3)	Allocation to LDCs (800 t, allowance value passed through to end users)	add 50 mwh ZCG @ \$3,000 and buy 800 t of allowances	\$50,000	\$3,000	\$20,000	\$73,000	\$70	\$500	\$20,000	\$50.95
(4)	Allocation to LDCs (800 t, 75% allowance value passed through to end users)	add 50 mwh ZCG @ \$3,000 and buy 800 t of allowances	\$50,000	\$3,000	\$20,000	\$73,000	\$70	\$500	\$15,000	\$55.71
(5)	320 t allocated to generation owners	add 50 mwh ZCG @ \$3,000 and buy 400 t of allowances	\$50,000	\$3,000	\$12,000	\$65,000	\$70	\$8,500	\$0	\$70.00

Calculation Details
In all lines generation is 1,050 mwh and emissions are 800 t Co2
Columns (1) and (2) represent the least cost option - 50 mwh of new ZCG
Column (3) is the cost of 1,000 mwh of coal-fired generation
Column (4) is the cost of 50 mwh of ZCG
Column (5) is the generation owners cost of allowance purchases (receipts from allowance sales)
Column (6) is the sum of columns (3), (4), and (5)
Column (7) is the market price the generation owner receives per mwh from the purchasing LDC
Column (8) = [Column (7) * 1,050] - column (6)
Column (9) is the revenue received by the LDC from allowance sales that goes toward reducing its revenue requirement
Column (10) = [Column (7) * 1,050 mwh - column (9)] / 1,050

b. Auctioned allowances

When generation owners must buy all of their allowances, the most profitable way to produce an additional 50 mwh is still ZCG. Even though generation expenses are identical to those with no-cost allowances (columns (3) and (4) of line (2)), the resulting profits are quite different. Generation owners now must purchase enough allowances to cover their 800 t of emissions from their 1,000 mwh of coal-fired generation (column (5)). This causes total costs to be \$20,000 higher, while the receipts from sales remain unchanged from line (1). So the identical choices and actions earn a far smaller profit (the \$500 in column (8) of line (2)) because the generation owner must incur the expense of purchasing allowances.

c. Allocation to LDCs

When 800 t of allowances are allocated to LDCs rather than to generation owners, the situation faced by the generation owner is identical to the result for auctioned allowances – 800 allowances must be purchased and profits are again \$500 (note that all entries having to do with the generation owner -- columns (1) – (8) of Table 9 -- are identical for this situation in line (3) and the auctioned allowances example in line (2)). The difference is that the allowances allocated to load can be sold by the LDC, with the revenues used under commission regulation to reduce the revenue requirement. The revenue that the LDC must collect from end-users is equal to the money paid to the generation owner – $1,050 \text{ mwh} * \$70 \text{ per mwh} = \$73,500$ – less the receipts of allowances applied to offsetting that revenue. The LDC in this example sells 800 allowances for \$20,000. If \$20,000 is applied to offset electricity purchase costs, the LDC collects \$53,500 from end users. The end user price is given by $\$53,300 / 1,050 \text{ mwh} = \50.95 per mwh (column (10)). If the LDC were to pass on only 75% of the allowance revenue to consumers, and use the other 25% for other purposes (example given on line (4)), it would apply $.75 * \$20,000 = 15,000$ to reducing its revenue requirement to \$58,500 and the end user price would be $\$58,500 / 1,050 \text{ mwh} = \55.71 per mwh (line 4, column (10) of Table 9).

d. Partial allocation of no-cost allowances to generation owners

When the price of electricity is set by marginal cost, generation owners' profits increase with the quantity of no-cost allowances they receive. Line (5) of Table 9 demonstrates that no-cost allocations of any quantity translate into additional profits equal to the value of those allowances. When generation owners receive 320 t of allowances at no cost, Column (8) shows that their profits are \$8,500 -- \$8,000 higher than when they receive no allowances. The value of 320 t of allowances is exactly \$8,000 ($320 \text{ t allowance} * \25 per t). The price of electricity to end-users remains unaffected.

3. Upstream administration

Upstream administration will bring about the same outcomes as downstream administration for generation owners under market pricing. Column (3) of Line (1) in Table 10 shows that the cost of generation is \$73,000 with upstream administration compared to \$53,000 with downstream administration (line (1) of Table (9)). This result reflects the fact that coal producers need 800 t of allowances to cover the CO₂ emissions in the coal purchased by

generation owners in order to produce 1,000 mwh of electricity. These 800 t of allowances (at \$25 per allowance) add \$20,000 to the cost supplying coal. Line (1) shows that when the generation owner receives 800 t of no-cost allowances, these produce \$20,000 of revenue and thus reduce total costs to \$53,000. Line (2) shows that when the generation owner does not receive no-cost allowances, total costs (column (6)) are \$73,000. Column (8) shows that profitability is unaffected by point of administration, which is the same for line (1) of Tables 9 and 10 for 800 t of no cost allocation to generation owners, and the same for line (2) of both tables for a zero allocation to generation owners.

**Table 10.
Example Results for Market Pricing and Upstream Administration: Generation Owner Profits and End User Pricing**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Allowance Allocation	Action by Generator	Cost of 1,000 mwh of Coal-fired generation	Cost of 50 mwh of ZCG Generation	Cost of Allowance Transactions	Total Costs	Price for Generation Owner (per mwh)	Profit for Generation Owner	Allowance Value Applied by LDC to End User Price	Price for End User (per mwh)
(1)	Allocation to Generators (800 t)	add 50 mwh ZCG @ \$3,000, sell 800 allowances	\$70,000	\$3,000	(\$20,000)	\$53,000	\$70	\$20,500	\$0	\$70.00
(2)	No Allocation to the Electric Industry	add 50 mwh ZCG @ \$3,000	\$70,000	\$3,000	\$0	\$73,000	\$70	\$500	\$0	\$70.00
(3)	Allocation to LDCs (800 t, allowance value passed through to end users)	add 50 mwh ZCG @ \$3,000	\$70,000	\$3,000	\$0	\$73,000	\$70	\$500	\$20,000	\$50.95
(4)	Allocation to LDCs (800 t, 75% of allowance value passed through to end users)	add 50 mwh ZCG @ \$3,000	\$70,000	\$3,000	\$0	\$73,000	\$70	\$500	\$15,000	\$55.71
(5)	400 t allocated to generation owners	add 50 mwh ZCG @ \$3,000 and sell 400 t of allowances	\$70,000	\$3,000	(\$8,000)	\$65,000	\$70	\$8,500	\$0	\$70.00

Calculation Details
In all lines generation is 1,050 mwh and emissions are 800 t Co2
Columns (1) and (2) represent the least cost option - 50 mwh of new ZCG
Column (3) is the cost of 1,000 mwh of coal-fired generation
Column (4) is the cost of 50 mwh of ZCG
Column (5) is the generation owners cost of allowance purchases (receipts from allowance sales)
Column (6) is the sum of columns (3), (4), and (5)
Column (7) is the market price the generation owner receives per mwh from the purchasing LDC
Column (8) = [Column (7) * 1,050] - column (6)
Column (9) is the revenue received by the LDC from allowance sales that goes toward reducing its revenue requirement
Column (10) = [Column (7) * 1,050 mwh - column (9)] / 1,050

E. Comparison between embedded cost ratemaking and market pricing

In cases where generation owners pay for all of the allowances that they need to comply with a GHG cap-and-trade, differences in price increases between embedded cost ratemaking and market pricing will depend on the differences between marginal and average compliance costs, on regulatory decisions that affect the efficiency of compliance choices under embedded cost ratemaking, and on rules about how expenses are passed through to ratepayers. The differences in price increases between these two markets could go either way. The cap-and-trade system is likely to have fairly similar effects on both types of arrangements.³¹

In cases where allowances are partially or fully allocated to generation owners without charge, commission decisions can cause price increases that are lower in embedded cost ratemaking markets than under market pricing. As illustrated in III.C and III.D, this difference is a result of commission authority to apply the value of allowances to reduce the revenue requirement in embedded cost ratemaking markets, and a lack of such ability in market pricing markets. This has two significant implications: one that affects equity, and one that affects efficiency.

The implication for equity is that the profits of generation owners in market pricing markets will rise substantially – a result commonly referred to as a windfall. Generation owners under embedded cost ratemaking will see no corresponding increase in profitability.

The implication for efficiency is that end users in embedded cost ratemaking markets will face prices that do not reflect the marginal cost of meeting GHG reduction. They will therefore have lower incentives to reduce energy consumption than other electricity end users and other covered economic sectors (e.g. transportation). Less conservation means a higher cost of GHG reduction for generation and higher allowance prices. Inefficiently low incentives to reduce electricity use also increase the overall costs of meeting GHG goals, because effort is not allocated efficiently throughout the economy.

Allocation to LDCs brings about a very different outcome here than allocation to generators.³² As illustrated in Parts III.C and III.D, commissioners can treat embedded cost ratemaking and wholesale competition symmetrically in deciding how to apply the value of

³¹ This does not mean that all generation will be affected equally. Areas served by high percentages of coal generation, for example, will see bigger effects than those highly dependent on hydropower. It does mean that when generators purchase all their allowances, generation that has the same carbon intensity will tend to receive fairly similar price signals from a GHG cap-and-trade regardless of whether they sell under embedded cost ratemaking or market pricing.

³² We contrast allocation to generation owners with allocation to LDCs in this report. Allocation to LSEs has very similar effects to allocation to generation owners: in cases where the LSEs are also LDCs, the allowance value will be under the control of state commission regulation. In cases where LSEs are not LDCs, effects will be as described in III.D.

allowances in setting end user prices. Allocation to LDCs also prevents windfall profits from accruing to generation owners.

F. End user response to price increases

In the interest of simplification, all the pricing examples used in Parts III.C and III.D treated the amount of electricity supplied as fixed. In fact, end users respond to price increases by using less electricity. There is a large literature and considerable debate about how large these usage reductions are, and about how quickly they take place. The following findings emerge consistently:³³

1. Historically, residential electricity use decreases by far less than 1% for every percentage point price increase in the short run. Over longer time periods electricity use decreases by more, with many studies finding changes in the range of 0.7% to 1% reduction for a 1% increase in price.
2. Much of the reduction in residential electricity use that results from price increases takes place through changes in capital equipment for, and operation of, electric heating and cooling.
3. Commercial and industrial responses to price changes follow a similar pattern, with electricity use being significantly more responsive to price in the long run than the short run.

In summary, higher electricity prices will induce at least some reductions in electricity use in the short run and will cause larger reductions in the long run. The implications of this for the results reported in Sections III.C and III.D are:

1. Electricity consumption will be lower than in the examples as consumers respond to higher prices with reduced consumption over time. These reductions will in turn lead to lower prices as the most expensive technologies are used less. End user conservation will also tend to reduce allowance prices, further reducing generation costs and output prices. To the extent that commissions use the value of allocated allowances to limit price increases, these consumption and price reduction effects will be smaller than when end users face the full marginal cost of generation.
2. LDCs that pass on the value of no-cost allowances to end users in the form of smaller price increases will sell more electricity, thus requiring more allowances

³³ A good presentation of state-by-state empirical evidence, as well as a survey of previous research, can be found in Bernstein and Griffin (2005), “Regional Differences in the Price-Elasticity of Demand For Energy,” Rand Corporation (available at https://www.rand.org/pubs/technical_reports/TR292/).

(holding the carbon intensity of generation constant) than LDCs that pass on the marginal cost of allowances through the end user price.

3. Areas that face a higher end user price will conserve more power over time, resulting in relatively lower demand for allowances than areas served by LDCs that limit price increases.

G. The allowance price

The examples in Part III were developed with a given allowance price. For any individual generator or LDC the allowance price will be established by the market. The collective decisions of generators, LDCs, and other entities covered by the system (for example, the transportation sector in an economy-wide system) will jointly determine the demand for allowances and have a direct influence on the price, which may fluctuate over time.

The market price will not be known with certainty, nor will it be constant. Once a national cap-and-trade system is operational, LDCs and generation owners will likely be able to manage this price uncertainty through the use of futures contracts on allowances. The use of futures and options on allowances will mitigate allowance price risk at the cost of higher average costs to cover the transactions costs of trading in these markets.

H. Supply decisions

The primary impetus toward zero- or low-carbon electric generation comes from the allowance price itself: higher allowance prices translate directly into greater incentives to produce electricity that requires few or no allowances to cover emissions. A given allowance price will convey the same advantage to low-GHG energy sources regardless of allocation or point of administration.

Proceeds from the sale of allowances by LDCs (or other public institutions that receive allowances) could be used to more directly support new low-carbon generation. Federal legislative proposals have already included such support through a national institution to be funded by the auctioning of allowances. This support is not a result of the cap-and-trade system, but of the decision to use financial resources to support research and implementation of specific technologies.

Utility commissions can affect generation and consumption decisions under embedded cost ratemaking through their treatment of compliance costs. Investments in low-GHG generation (wind, geothermal, biomass, or nuclear) are likely to have higher costs than conventional coal-fired generation when allowance costs are not considered. The same is true of expenditures to make new or modified coal-fired generation compatible with carbon capture and storage. The risk of high prices represented by these investments will depend on costs and efficiency of the technologies as well as the allowance price, all of which have some unpredictable elements. Commissions will have to balance end user price risk of these technologies against their potential for effective GHG reduction. Their choices will directly influence new generation capital and its GHG emissions characteristics.

IV. Commission Interest in Cap-and-Trade Design Elements

A. Program breadth

Commissions have an interest in advocating for an economy-wide program – or at least one that includes the industrial and transportation sectors – for two reasons. The first is that in an electric industry-only program end-user prices will have to rise significantly higher to achieve the same overall reductions that would be achievable at lower prices in a broader system. This is because achieving a given level of reductions from a narrower segment of the energy system will be more costly than achieving that same level of reduction from all use of fossil fuels. The second factor is that focusing on the electric industry would tend to cause energy supply to move away from electric generation under commission oversight and toward small unregulated generation or direct power production by industry. This would cause additional GHG emissions that would offset the reductions by the electric industry. It would also disadvantage the electric industry relative to competitors supplying energy to the same markets. For example, natural gas for home heating, if not covered by a cap-and-trade system, would gain an advantage over electric generation that is covered.

A program that covers higher percentages of GHG emissions will have a larger and more diverse allowance market, and therefore will tend to have less volatile prices and a more liquid allowance market. This tendency will help the electric industry to plan compliance strategies and to make adjustments for unexpected changes in emissions. The benefits of a larger and more diverse market also favor a program that covers multiple GHGs rather than just CO₂, although measurement and administration becomes more difficult for non-CO₂ gases.

One characteristic of an electric industry-only system is that there would be less competition for offsets and other external sources of allowances. This would tend to make using offsets for compliance less expensive, all else equal. A possible advantage of an electric industry-only program is administrative simplicity, particularly if a system were administered downstream, although this feature would affect the administrators of the system but have little effect on either generation owners or commission oversight.

B. Stringency of the cap

The decision about cap stringency is a political choice about the nation's level of commitment to emissions reductions. State commissions can legitimately concern themselves with making sure the utility sector is not unfairly singled out for reductions in a narrow system. This report finds no reason that commissions have an interest in a more or less stringent cap in terms of their obligation to ratepayers.

C. Allocation and point of administration

Allocation and point of administration are frequently discussed together. This report has stressed that technically (although maybe not politically) they are separate issues. Allowance allocation is a political choice that has a very direct impact on who gains and who loses from the

implementation of a cap-and-trade system for GHG limitation. Point of administration is a technical choice that has to do with how emissions are measured and allowances are tracked. This section discusses the relative merits of alternative designs for these two parameters.

1. Point of administration

Downstream administration is familiar to utilities and commissions from SO₂ and NO_x trading programs. It imposes relatively small additional monitoring costs on generation owners. From the standpoint of commissions, downstream administration creates complex regulation choices relating to the sale and purchase of allowances, choices that are less troublesome with other points of administration. From an overall program design perspective, downstream administration is not feasible for the transportation sector and some other parts of the energy system. A hybrid system of differing points of administration for different sectors may therefore be required for a broad-based program, creating some additional administrative complexity and expense.

Upstream administration is fully compatible with an economy-wide system and also makes allowance sale behavior transparent to commission regulation. It has the advantage of low administration costs as well. The system can be administered at a fairly limited number of coal mines and processing plants, natural gas pipelines, and oil refineries and can cover the overwhelming majority of fossil fuel combustion. Generators see the price of allowance in the fuel they buy, and therefore do not actually buy and sell allowances as a compliance option. In fact, utilities have no specific compliance obligations under an upstream system – they simply have to deal with more expensive fuel inputs, with the price increases strongly influenced by the CO₂ content of fuel.

Since upstream administration is a new and untested system, there could be unanticipated implementation problems. Interest groups that oppose upstream systems believe that generators and/or LSEs will not seek out GHG reductions as aggressively or creatively when they are responding to a pure price signal as in the situation where they are buying and selling actual allowances.

An argument made for administration at the level of LSEs builds on this latter point. It holds that LSEs are best able to seek out and encourage the most efficient mix of technologies to meet GHG reduction goals. The downside is administratively complexity, since LSEs will have to track the GHG emissions from all sources from which they buy power. This tracking task becomes even more difficult when sources sell to multiple LSEs or power is bought through an ISO, RTO or some other form of power pool. As with downstream administration, an LSE-based system requires a separate system (or systems) to administer other covered sectors of the economy.

We have discussed how treatment of allowance purchases and sales can interact with utility regulation to create complexity and imperfect incentives to find efficient compliance options. Upstream administration is the system that is likely to best alleviate these problems,

since the only market transaction that generation owners or LDCs will make is to sell any no-cost allowances to fossil fuel companies.³⁴

One additional complexity of upstream administration concerns carbon capture and storage. If generators can prevent all or part of the CO₂ in their fuel from being released into the atmosphere, they need to be credited for that reduction or they will have no incentive to invest in CCS technology. This crediting can be accomplished by granting allowances equal to the amount of CO₂ that is sequestered (see Box 3). These allowances would then be sold to fossil fuel companies on the general allowance market. The tracking and verification of sequestration is the same as would be needed with any other point of administration, but the granting of allowances is an additional step not needed in other systems.

2. Allowance allocation

Parts III.C and III.D discuss how allocating allowances to generation units – whether it is all allowances associated with electricity generation or a fraction of those allowances – creates two potential problems for commission regulation. First is the division of the value of those allowances between ratepayers and shareholders when they are sold. Commissions face a challenge in reconciling incentives for efficient GHG reduction – which requires that generators receive some benefit from sales or incur a penalty for failing to undertake prudent sales – with their interest in passing on the value of allowances to ratepayers. Second is the differential effect on pricing and shareholder value between embedded cost ratemaking and market pricing. No-cost allowances will not affect the price that generation owners receive under market pricing, and can therefore create windfall profits.

Allocating allowances to LDCs avoids both of these problems. The LDCs can use all or part of the value of allowances to reduce the prices paid by end users, or they can use all or part of the value to engage in DSM or support alternative energy generation. The decision rests on the way the commissioners choose to incorporate allowance value into end user pricing. LDCs can apply the value of their allowances equally to power obtained from embedded cost ratemaking and market pricing, removing a major source of the price difference between the two and creating more equal treatment of shareholders of both types of generation. This analysis finds that Commissions therefore have an interest in advocating that allowances allocated without cost to the electric industry go to LDCs rather than generation units.

No-cost allowances can be given out based on a variety of measures of historical performance or emissions, with the consequences being the division of wealth among the recipients. One decision where Commissions have an interest is in whether an updating formula is used or not (see Box 4). Updating is likely to result in lower end user prices, and will thus be an attractive formula for Commission interests in limiting the price increases from a cap-and-

³⁴ Generation owners may buy futures or options in allowances as part of a strategy to hedge price risk. Commissions should be able to regulate these hedging decisions in the same way they regulate price-risk management options for fuel sources.

trade program. Updating is also likely to result in less conservation behavior (because of the lower price) and reduced shareholder value for generation owners.

Allowances can also be auctioned by the federal government or distributed to entities outside the utility industry that would then sell them and use the resources for public purposes. This allocation scheme removes decision-making authority over allowance value from Commissions, and treats all generators equally. It therefore means that Commissions lose power to use allowance value to cushion the effect of allowance prices on end user prices, or to control the use of allowance value to support DSM or other commission-backed programs.

3. Administration, allocation, and policy formation

This report has emphasized that point of administration and allocation are separate decisions in designing a GHG cap-and-trade policy. Commissions should be aware that this distinction might not be made clearly in the politics of formulating a national GHG policy. Generation owners may favor downstream administration for the electric power industry because they believe it increases the likelihood and quantity of no-cost allowances they will receive. If commissions see advantages in downstream administration but believe other allocation schemes – in particular, allocation to LDCs – are preferable, they will need to articulate this difference clearly in their participation in the policy formation process.

D. Offset rules

Stricter rules for measuring and verifying offsets – for example, from carbon sequestration in agriculture and forestry – reduce the supply of offsets coming into the cap-and-trade system and therefore increase the price of allowances, making compliance more expensive. Fair and consistent rules increase the environmental integrity of the cap-and-trade program and are consistent with its broader purpose. Rules that are reasonable and not unnecessarily complex or burdensome will increase the efficiency of offset provision. The policy challenge is to craft offset rules that accurately track and measure real GHG reductions while still promoting efficient offset supply. Commissions share a broader interest in striking the best balance between environmental integrity and cost-effective GHG reduction.

E. Safety valve

A safety valve places a pre-announced maximum on allowance prices. It removes the risk of very high allowance prices when generation owners choose compliance strategies, and therefore will result in greater certainty and lower costs than an equivalent cap-and-trade program without a safety valve. The effect of this policy depends critically on the level of the safety valve relative to expected allowance prices – the lower the safety valve, the greater the degree of containing price risk in the allowance and electricity markets. However, this reduced risk from lower safety valve prices is accompanied by a greater probability of exceeding the GHG cap and a weaker overall program.

A safety valve will tend to eliminate both higher-cost and more risky investments in GHG reduction. If a particular technology will be competitive only at high allowance prices, a safety valve will make such an investment less attractive by reducing the average expected price.

F. Commission decisions, end user pricing, and the public interest

Part III of this report analyzed the role of commission regulation in end-user pricing and generation owner choice in a national cap-and-trade program. A central theme of this analysis is that commissions will have to balance elements of serving the public interest in a more complex environment. The chief balance has historically been to find the best tradeoff possible between a reliable supply of electricity and a reasonable price for that electricity. The centrality of the electric industry in any national effort to curb GHG emissions potentially brings a new element into commission deliberations.

The crux of the issue is that low electricity prices bring about less end user conservation than higher prices. Achieving GHG reductions at low cost for the nation as a whole requires an efficient balancing of end user conservation and changes in generation technologies. The price of allowances will have a direct influence on generation technology choice. If Commission decisions use the value of allowances to avoid this full cost being passed on to end users, then too much effort and expense will be applied to generation technology relative to lower-cost reductions available from electricity users. If significant numbers of allowances are allocated to generators, then commission decisions will affect the changes in the relative price of electricity between areas with more and less market pricing.

This report has discussed the two ways that such end user conservation can be affected by Commission decisions. One is the effect of higher prices. The other is the use of resources by generators, LDCs, or other public and private entities to seek out, support, and implement DSM activities. In general these two drivers of conservation are compatible – higher end user prices can be turned into resources to fund DSM programs. If the value of no-cost allowances is not fully used to reduce the revenue requirement met by end users, LDCs will retain resources that Commissions can direct to other uses. Demand side management activities are obvious candidates. Higher end user prices will give all classes of consumers greater incentives to seek out and put effort into DSM programs, while also giving incentives for more general effort toward conservation in operations and investment choices.

Commissions may also have a concern with protecting specific segments of their end user communities from economic hardship caused by passing through the marginal cost of allowances into electricity prices. This concern may apply to low-income consumers and to energy-intensive industries whose ability to provide jobs is at issue. Commissioners can try to alleviate this economic hardship in three ways. One is to use allocated allowance value to minimize price increases, as demonstrated in Part III. This option has the obvious disadvantage of giving the same reduced conservation incentives to all end users. A second method is some kind of differential pricing structure – whether it is lifeline rates to low income consumers or special rates for specific industries. This approach has the advantage of preserving conservation incentives for non-targeted end users. It has the disadvantages of complexity, and of creating a

situation where Commissions will be pressured and criticized for not extending lower prices to a larger group of end users (all of whom would prefer lower prices).

The third option is to use resources generated by no-cost allowances to fund conservation investments in the targeted end user groups. Examples of such programs include insulation and appliance retrofitting programs for public and low-income housing. End users would still pay higher prices at the margin, leaving conservation incentives intact, but would receive specific assistance to reduce their overall costs. Such an approach raises a general concern of commission management of the effective and efficient implementation of these programs.

To the extent that Commissions see contributing to the national effort for efficient GHG reduction as part of their role of promoting utility operation in the public interest, they may wish to consider incorporating end user conservation incentives in their decision-making. If Commissions believe they should focus on their core mission of reliability and cost for end users, they will tend to deemphasize concerns with balancing incentives between end-users and generators, and among different geographical areas.

V. Compatibility of Cap-and-Trade with Other State and National Mandatory Policies

In this section we will briefly outline the most important factors in how other relevant policies will fit in with a national cap-and-trade system. There are two kinds of policies that are potentially important: renewable portfolio standards³⁵ and state and regional cap-and-trade programs.

A. Overlap with RPS policies

Renewable portfolio standards are policies that specify that a minimum percentage of electricity supply must come from a chosen set of technologies. While these technologies tend to be low in the production of GHGs, this is not universally the case.³⁶ There are currently 25 states plus the District of Columbia that have implemented, or have passed and are in the process of implementing, an RPS. The characteristics of these programs differ significantly from state to state. Legislation for a federal RPS has been introduced but not passed.

RPS policies generally provide flexibility to meet their overall percentage goal by allowing the purchase and sale of credits for qualifying generation. The flexibility provided by this trading means that it is not necessary that each generation unit or each LSE meet the minimum RPS percentage from the power it produces and sells, only that it be met in aggregate for the state.

The idea behind RPS policies is to give a boost to renewable generation without choosing or mandating specific technologies. They have the effect of increasing the percentage of renewable generation in a state. Since this effect will strongly tend to decrease the GHG intensity of any given amount of generation, such policies will make it less expensive to comply with a GHG cap-and-trade policy than would otherwise be the case. To the extent that RPS policies are result in some increase in consumer electricity prices,³⁷ they will also tend to make compliance easier by having slightly reduced overall electricity production (due to the price-induced decline in demand).

³⁵ Also called renewable energy standards, renewable energy portfolio standards, and a variety of similar names involving variants on this basic approach. An explanation and inventory of these programs can be found at http://www.ucsusa.org/clean_energy/clean_energy_policies/index-renewable-electricity-standards.html http://www.ucsusa.org/clean_energy/clean_energy_policies/index-renewable-electricity-standards.html.

³⁶ For example, Pennsylvania's RPS includes coal waste as qualifying energy source. The use of coal waste may help achieve overall environmental goals but will not bring down GHG emissions.

³⁷ Because of the structure of dispatch markets, there are circumstances where RPS policies may raise the overall cost of electric generation but not raise consumer prices.

There is no technical reason why RPS policies and a GHG cap-and-trade cannot easily coexist. There is also no reason why any interactions should cause any particularly difficult decisions for commissioners. One prediction that commissioners should be aware of is that a GHG cap-and-trade may not provide a significant boost for renewable energy sources, even though they will gain a price advantage from such a program. Both natural gas generation and demand-side management may prove to be less expensive compliance mechanisms, and it is possible that CCS from coal plants could also prove more competitive than renewable generation in many contexts if continued innovation reduces its costs. If the goal of RPS policies is to get a renewable industry off the ground, then it may well prove useful even in the presence of mandatory limits on GHGs.

B. Overlapping cap-and-trade programs

The Regional Greenhouse Gas Initiative (RGGI) is set to become operational and cover the emissions of ten Northeastern states in 2009, with several other states interested in or formally planning to join. RGGI covers only electric generation emissions produced in participating states. California is in the process of designing a cap-and-trade program to meet the requirements of Assembly Bill 32, passed in August of 2006. The scope, design, and timing of this program have yet to be determined. California is also pursuing discussions with five western states and two Canadian provinces for regional action, which might include a cap-and-trade program, under the Western Regional Climate Action Initiative.³⁸

Any or all of these programs might be operational at the time a national cap-and-trade policy is passed and implemented. Although a full analysis of how these systems might coexist is beyond the scope of this report, in this section we describe how overlapping systems might work.

One possibility is that state/regional programs will dissolve themselves in favor of the federal program. If this does not take place, then utilities will be under simultaneous regulation by both programs. In this case, the effects depend on which system creates a higher price for CO₂ allowances.

If the national system is characterized by a higher price, then the state/regional program will essentially be made irrelevant. Take RGGI as an example, and assume that without a national system the RGGI market would clear at an allowance price of \$15 per CO₂ in order to meet its reduction obligations. If a national system were characterized by a CO₂ price of \$25

³⁸ State and regional cap-and-trade systems face some complexities that are not present in a national system because of the complexity of the interstate transmission of electricity. These questions are addressed in general terms in Keeler (2004) "An Evaluation of State Carbon Dioxide Reduction Policies", available at http://www.cpc-inc.org/assets/library/18_21keelermay0.pdf, and are discussed in the context of state program design for California in CARB (2007), "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California," available at http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF.

per t, then utilities and end users in the system would respond to that price by greater GHG reductions than they would have achieved from the RGGI cap. This means that there would be more RGGI allowances than emissions, so these allowances would lose their value and the national system would drive all costs and actions.

If the national system were less aggressive and were characterized by a lower allowance price, then the effects are quite different. If the example above were modified so that the GHG price in a national system were \$5, then the utilities in RGGI would need to hold both a \$15 RGGI allowance and a \$5 national allowance for every ton emitted. The effective price for a ton of CO₂ emissions would be \$20, so RGGI generators and end users would reduce emissions by more than with either system alone. They would also reduce CO₂ more than parts of the country covered only by a national system, thus demanding fewer national allowances and causing the price of those allowances to be lower than it would otherwise be. These additional reductions would be balanced by lower reduction effort in states covered only by the national program, so that the national level of GHG emissions would be unaffected by the existence of separate state programs.

VI. Conclusions

This report has explained and analyzed the ways that a federal cap-and-trade policy to limit GHGs will affect technology choice and pricing in the U.S. electric industry. It has emphasized that the design and implementation of a cap-and-trade system is critical to its effects on electric generation. Allowance allocation in particular affects the pricing of electricity and the profitability of producing it. The options included in a cap-and-trade system to manage price risk and expand compliance alternatives – banking, borrowing, a safety valve, and offsets – all have the potential to influence the price of GHG allowances and the cost of electricity production. Administrative design -- the point at which GHG emissions are measured against allowances to determine compliance -- affects the transparency and administrative complexity of the system.

A GHG cap-and-trade system will affect commission regulation in a number of ways. The consequences will be more direct and important for commission regulation of generation owners through embedded cost ratemaking. In the near term, commissions will have to make construction approval decisions under uncertainty about compliance costs and the effectiveness of new technologies. The cost of allowances, and the way they are allocated, directly affects ratemaking.

Commissions have less effect on the pricing and technology choices made by generation owners that sell under market pricing arrangements. Allowance allocation to generation owners under market pricing can result in windfall profits. If GHG allowances are allocated to LDCs rather than generation owners, commissions do have influence on the end user pricing of that electricity.

When the electric industry is allocated GHG allowances at no cost, commissions will make decisions that set the balance between protecting end users from rate increases and allowing increasing rates to set efficient incentives for end user conservation. If commissions believe that the public interest includes cost-effective GHG reduction, then they will tend toward letting rates include the full costs of meeting GHG limits. If their view of the public interest focuses more on limiting rate increases, an inefficiently low amount of end user conservation will take place.

The report discusses the advantages and disadvantages of different design criteria for the electric industry. It makes two unambiguous recommendations about design elements that commissions should support. One is that the electric industry and the public are best served by a GHG cap-and-trade that covers the largest possible share of U.S. GHG emissions, and not just electricity production. An electricity-only system will allow the inefficient leakage of generation from the electric industry to energy production not covered by the narrow system. A broader system would prevent such inefficiency and find the most efficient GHG reductions throughout the economy.

The second recommendation is that allowances allocated to the electric industry at no cost should be allocated to LDCs, and not to the owners of generation. Allocating allowances to LDCs treats generation owners producing under embedded cost ratemaking and those producing

under market pricing symmetrically, and gives commissions the ability to treat end users of electricity from different pricing regimes more equally. This report does *not* take a position on whether allowances should be allocated to the electric industry without cost. It does find that any allowances so allocated should go to LDCs and not to generation owners.

A national cap-and-trade policy can coexist with state and national energy portfolio standards without difficulty. The simultaneous implementation of a national cap-and-trade with regional cap-and-trades like the Regional Greenhouse Gas Initiative and the proposed Western Consortium is more problematic and will depend on details that have yet to be worked out.

Mandatory limits on GHGs will be a part of energy production and use for a very long time. The electric industry has begun to consider how it will navigate living with these limits. There is currently uncertainty about the timing and severity of GHG constraints on electric generation that will result from a federal program. Commissions need to understand how their mission will be affected by federal policy and to begin to craft strategies and procedures to best serve the public interest in this new environment.

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