RGGI Regional Greenhouse Gas Initiative
An Initiative of the Northeast & Mid-Atlantic States of the U.S.

Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI)

Final Report of the RGGI Emissions Leakage Multi-State Staff Working Group to the RGGI Agency Heads

March 2008

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EXECUTIVE SUMMARY

Introduction

"Emissions leakage" is the concept that there could be a shift of electricity generation from sources subject to a RGGI cap-and-trade program to higher-emitting sources not subject to RGGI that results in a net increase in carbon dioxide (CO_2) emissions. The implementation of a carbon cap on power plants is expected to increase the cost of electricity generation in the RGGI region. In a competitive power market, this may have the effect of shifting generation in the larger region to uncontrolled, and presumably cheaper, fossil fuel-fired generation not subject to a carbon cap.

Because RGGI is being implemented in a competitive generation market, the addition of a carbon compliance cost that applies to only a subset of electric generators in the market could lead to a shift in the dispatch of electric generators and changes in flows of energy on the transmission system in response to this CO_2 price signal. The concept of emissions leakage is, therefore, specific to a scenario where a larger national program does not exist and a regional program is being implemented that does not fully cover the respective regional wholesale electricity markets.

Background

In the December 20, 2005, RGGI Memorandum of Understanding ("MOU"), the RGGI Agency Heads recognized the potential for emissions leakage to undermine the goals of a RGGI cap-and-trade program. In acknowledging this possibility, the Agency Heads directed staff to study this phenomenon, provide recommendations to monitor it, and analyze policy responses that would be capable of addressing emissions leakage if necessary.

On March 14, 2007, The Emissions Leakage Staff Working Group (Staff) submitted to the Agency Heads a report: *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms* (Initial Report). That report reviewed wholesale electricity market dynamics that could drive or mitigate emissions leakage; provided a detailed proposal for monitoring potential leakage; and surveyed potential policies and measures for mitigating leakage. With the exception of the leakage monitoring proposal, the Initial Report did not make any policy recommendations, but instead provided a qualitative analysis of various leakage mitigation options as a starting point for Agency Heads discussion.

The purpose of this report is to provide Staff's conclusions and final recommendations with respect to: I) modification of tracking systems in the three ISO regions to monitor potential emissions leakage; II) the current political momentum toward a national cap-and-trade program; and III) leakage mitigation policy options that should be prioritized for implementation. Staff's conclusions and final recommendations are based upon, in part, additional feedback from Agency Heads, independent experts, the regional ISOs, and stakeholders.[1]

Tracking Systems to Monitoring Emissions Leakage

In the Initial Report, Staff concluded that in order to monitor and quantify the extent of potential emissions leakage it is essential to be able to track the environmental attributes associated with all the power being used within the RGGI region.[2] Staff made specific recommendations for monitoring leakage that would require minor modifications of existing generation attribute tracking systems that are currently used in the region's electricity markets.

With the submittal of the Initial Report, Staff began pursuing discussions with the appropriate parties responsible for proposing modifications to the current tracking systems in both the New England and PJM control areas. Consequently, on November 16, 2007, the ISO-New England Participants Committee approved RGGI's monitoring proposals, thereby authorizing ISO-New England's Generation Information System (GIS) administrator to make the requested changes to its software platform and operating rules. A similar commitment by PJM's Generation Attribute Tracking System (GATS) administrator was also made in November 2007, and the modifications necessary in both control areas are expected to be coordinated and implemented by the end of the first quarter of 2008 to allow for tracking of data for the full 2008 calendar year. These two tracking systems cover nine out of the ten RGGI States.

In New York State, which has a separate and distinct generator attribute tracking system currently administered by the Department of Public Service (NYDPS), efforts to automate its tracking system are currently under review by the NYDPS, the New York State Energy Research and Development Authority (NYSERDA) and the New York ISO. The goal is to develop a tracking system compatible with the surrounding regions while still supporting current NYDPS environmental programs and policies. Implementation of a modified New York tracking system is currently scheduled for late 2008.

Staff concludes that by the end of 2008, there will be sufficient baseline data for the ISO-New England and PJM control areas against which to measure potential leakage after the implementation of the RGGI program.

Political Momentum toward a National Carbon Cap-and-Trade Program

The current political environment strongly suggests a growing awareness of, and concern over, climate change on the part of regulators, businesses and other interest groups. As of January 2008, there were 12 pieces of legislation pending in Congress that would establish cap-and-trade programs addressing greenhouse gas emissions. Environmental organizations and the business community are urging Congress to develop climate change legislation. State utility regulators across the country are also becoming increasingly aware of the

[1] See Appendix I for a list of stakeholders that have filed comments on the March 14, 2007, Initial Report.
[2] *See* Section III of Initial Report at 11-26.

various options before Congress to regulate carbon dioxide emissions from electric generation facilities. Recently, three of the world's leading financial institutions announced guidelines for advisors and lenders to electric generation companies in the United States, designed to assist in evaluating and addressing current and future carbon regulatory risks in the financing of electric power projects.

These and other activities cause Staff to conclude that there is emerging nation-wide support for the development and implementation of a national cap-and-trade program to address greenhouse gas emissions. In its Initial Report, Staff noted that the implementation of a national program "would in large part address the emissions leakage issue," and explained that:

> The implementation of a national CO_2 cap-and-trade program for the electric power sector that is equivalent to RGGI, or a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage.[3]

For this reason, Staff recommends that the RGGI participating states prioritize the implementation of leakage mitigation measures that have demonstrated effectiveness and that can be implemented relatively quickly, relative to more complex measures that would require greater implementation lead times and pose significant implementation challenges that may limit their effectiveness.

Evaluation of Emissions Leakage Mitigation Measures in RGGI Participating States

On January 13, 2008, the State of New Jersey enacted legislation requiring the New Jersey Board of Public Utilities (BPU) to adopt, by July 1, 2009, rules establishing a greenhouse gas emissions portfolio standard (EPS) or another regulatory mechanism to mitigate emissions leakage, applicable to all electric power suppliers and basic generation service providers that provide electricity to customers within the State.[4] In response to this legislation, on March 18, 2008, the New Jersey BPU issued an order to convene a proceeding to evaluate emissions leakage mitigation measures.[5] That proceeding will, in part, gather relevant information about an EPS and other potential leakage mitigation measures by conducting a public stakeholder process, to be followed by a public hearing, on the selection of appropriate leakage mitigation policies and practices.

Policy Recommendations for Addressing Potential Emissions Leakage

In its Initial Report, Staff identified three broad categories of policies for addressing potential emissions leakage. These categories include policies that:

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[3] *See* Initial Report at note 19 and accompanying text.
[4] See P.L. 2007, c.340 supplements Title 26 of the Revised Statutes, and amends the Electric Discount and Energy Competition Act, P .L.1999, c.23, N.J.S.A. 48:3-49 et seq.
[5] See BPU Docket No. EO08030150 - "In The Matter of A Greenhouse Gas Emissions Portfolio Standard and Other Regulatory Mechanisms to Mitigate Leakage."

1. Indirectly address carbon emissions by reducing electricity demand;

2. Directly address, but do not cap, carbon emissions related to electricity use; and

3. Cap carbon emissions related to electricity use.

Evaluation Criteria

In the Initial Report, Staff identified criteria to consider when evaluating each category of policy options above. Staff recommended that RGGI participating states consider the extent to which each option:

1. Accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner;

2. Maintains and/or enhances electric system reliability;

3. Ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region;

4. Remains relevant even after a mandatory federal greenhouse gas emissions reduction policy is in place;

5. Encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity; and

6. Is compatible with other energy and environmental policies that address the end-use of electricity.

Subsequent to the release of the Initial Report, Agency Heads directed Staff to also consider the following additional evaluation criteria:

7. Policy development and implementation time frame; and

8. Significant administrative hurdles and considerations.

In this report, Staff evaluates the extent to which each potential leakage mitigation policy outlined in the Initial Report meets these criteria.

Category 1 -- Policies that Reduce Electricity Demand

In the Initial Report, Staff recommended a package of policies that RGGI participating states could implement to reduce electricity use and demand in the RGGI region that would indirectly address carbon emissions and mitigate potential emissions leakage, referred to as Category-1 policies. These measures included:

1. Maximization of RGGI allowance allocation dedicated to support end-use energy efficiency;

2. Implementation of energy efficiency portfolio standards;

3. Harmonization across the RGGI region of the most up-to-date building energy codes and standards for commercial and residential buildings;

4. Harmonization across the RGGI region of the most up-to-date appliance and equipment energy efficiency standards; and

5. Development and implementation of policies and market incentives to reduce market barriers to combined heat and power (CHP) and other clean distributed generation.

The policy options in Category 1 are designed to reduce electricity demand, and therefore can be expected, in turn, to help avoid emissions leakage. Policies that reduce electricity demand will reduce demand for CO_2 allowances and reduce allowance prices, and thereby reduce the generation-cost differential imposed on RGGI-affected generation units relative to generation units that are not subject to the RGGI cap. This is expected to reduce the potential for emissions leakage. To the degree that overall electricity demand in the RGGI region is reduced, the demand for electricity generation not subject to the RGGI cap, and related emissions, should also be reduced.

Revenue from the auction or sale of RGGI CO_2 allowances could significantly support further investment in end-use energy efficiency. If 100 percent of the RGGI participating states' CO_2 emissions budgets are auctioned, the resulting revenue, assuming an allowance price of $3 per ton, could result in a 15 percent to 664 percent increase in state per capita spending on energy efficiency market transformation programs. Assuming an annual indicative performance level of 250 kWhs of electricity initially saved for every dollar invested, this could result in a 1.3 percent reduction in projected regional electricity use in 2012, a 2.4 percent reduction in 2015, and a 5.1 percent reduction in 2021. Based on electricity simulation modeling conducted to support the development of the RGGI program, such a level of demand reduction would have a significant impact in lowering allowance prices and reducing projected emissions leakage.

Staff concludes that end-use energy efficiency measures could be implemented relatively quickly given the current policy and program infrastructure in place in most RGGI states. While the scope and aggressiveness of end-use energy efficiency policies, standards, and market transformation programs varies significantly across RGGI states, expansion of programs to support end-use energy efficiency and the implementation of additional energy efficiency policies, should not require significant lead-times.

Staff also notes that the implementation of such policies and programs would provide significant net ratepayer benefits, as evidenced through the implementation of similar policies throughout the RGGI region. Aggressive end-use energy efficiency policies would also complement the implementation of a federal carbon cap-and-trade program by moderating allowance prices and containing compliance costs, which would mitigate the ratepayer impacts of such a program.

Category 2 - Carbon Adder and Emissions Rate Mechanisms

The second category of policies described in the Initial Report, referred to as Category-2 policies, would directly address carbon emissions. These policies include:

(1) *Carbon procurement adder* - an analytical tool that requires a load-serving entity (LSE) planning its electricity supply resource acquisitions to incorporate a "shadow price" for carbon emissions into its financial analysis of different investment options;

(2) *Carbon procurement emissions rate* - a limit placed on the emissions rate of power supplied to an LSE through a long-term power purchase agreement; and

(3) *Emissions portfolio standard* - a policy mechanism that would require an LSE to meet an average, output-based emissions standard (lbs. CO_2/MWh) for the portfolio of supply resources the LSE uses to provide retail electricity.

Each of these policies have positive aspects inherent in their intended objective of mitigating leakage, however, there are also significant design and implementation challenges that arise from the market context in which these policies would be implemented and the technical challenges related to tracking the emissions associated with electricity use. The characteristics of each policy have implications for its effectiveness in mitigating potential leakage, the appropriateness of its use in the RGGI region, and the complexity associated with its implementation.

A carbon procurement adder, for example, can be expected to effectively internalize future carbon regulatory risk in a Load Serving Entity's (LSE) planning process, and therefore provide a utility with a mechanism with which to better evaluate resource supply options. However, such a mechanism would be challenging to implement in a restructured electricity market, absent significant modification to typical procurement processes. In particular, such a mechanism would present a challenge for use as a planning tool to evaluate the carbon intensity of spot market power purchases, which are a mix of system power that include both low- and high-emitting units.

A carbon procurement emissions rate mechanism would be tied to the bundled electricity commodity, rather than an unbundled emissions attribute, and therefore would directly impact power plant dispatch. However, this policy is not suited to addressing power purchases from the spot market, and therefore would be of limited use in the RGGI region.

An emissions portfolio standard (EPS) would impose a market signal on LSEs that lower-emitting generation is a valuable commodity. However, for purposes of mitigating emissions leakage, an EPS would only indirectly impact the dispatch of generators in the region. Since an EPS imposes procurement requirements on LSEs, this mechanism could be expected to affect generation dispatch to the degree that all LSEs in the market were required to comply with the mechanism. However, such regulatory scope would not be possible in the PJM control area, the control area of greatest concern with regard to potential emissions leakage.

Staff concludes that the development and implementation of a carbon procurement adder, carbon procurement emissions rate, and emissions portfolio standard can be expected to require significant lead time to develop and implement, requiring significant involvement by both energy and environmental agencies.

Staff notes that the efficacy of such policies remains unclear and could depend on their specific design and the market context and geographic scope in which they are implemented. Staff also notes that the implementation of such policies could have significant ratepayer impacts, some of which might overlap with the ratepayer impacts of the RGGI program, without providing significant incremental environmental benefits.

Finally, Staff notes that Category-2 policies would likely provide limited incremental environmental benefits, beyond those benefits realized through Category-1 policies, once a federal carbon cap-and-trade program is implemented. Moreover, the implementation of such policies could also result in significant incremental ratepayer impacts beyond those expected to result from a federal carbon cap-and-trade program.

Category 3 – Capping Emissions Associated with Serving Load

The third policy category, referred to as a “load-based emissions cap-and-trade program (load-based cap)”, would place a cap on absolute emissions related to all electricity delivered for retail sale by an LSE or multiple LSEs.

For this policy, allowances would be allocated to individual LSEs, either directly or via an auction. At the end of each compliance period, LSEs would have to submit allowances equivalent to the carbon emissions associated with the generation supply that the LSE used to serve its load.

As noted in the Initial Report, “[t]his approach would be effective in addressing the majority of any potential emissions leakage. Assigning a carbon cap to LSEs eliminates the ability of LSE procurement decisions in response to the RGGI program to contribute to incremental emissions increases from generation not subject to a carbon constraint.”[6] However, staff further notes that

[6] *See* Initial Report at ES-11.

the effectiveness of such a mechanism is dependent of the geographic scope to which the mechanism is applied.

Although a load-based cap has positive features, the implementation of this policy would also likely be accompanied by numerous challenges. The development of a load-based cap could require legislative authorization in some states, followed by the development of an extensive regulatory framework, resulting in a substantial implementation lead time. This would include the development of individual LSE emissions budgets, allocation of allowances, a system for tracking emissions and allowances, and a system for tracking power purchases and related environmental attributes. In addition, Staff notes that determining the level of emissions attributable to electricity use by LSEs is subject to a significant degree of uncertainty compared to the determination of emissions under a generator-based cap-and-trade system, due to the need to apply emissions proxies to certain types of power purchases.

There is the possibility that a load-based cap could be subject to "attribute shuffling" and a related strategy known as "contract shuffling." In a market where not all electricity sales are subject to a load-based cap, it may be possible for buyers and sellers to "shuffle" attributes or contracts, and for LSEs to comply with a load-based cap without impacting the emissions profile of the regional power system. These challenges are addressed in detail in the Initial Report and in Section V of this report.

Given such implementation challenges, the success of a load-based cap would depend on the geographic scope to which it is applied as a percentage of the territory covered by a respective wholesale electricity market. Staff notes that the policy would not be applied to a majority of load in the PJM control area, the area of primary concern with regard to leakage potential. Staff also concludes that it is questionable whether such a program, applied on a regional level, could be launched in a time frame that would provide significant value in the near- to mid-term as a leakage mitigation mechanism.

Finally, Staff notes that a load-based cap would likely provide limited incremental environmental benefits, beyond those benefits realized through Category-1 policies, once a federal carbon cap-and-trade program is implemented. The implementation of such a program could also result in significant incremental ratepayer impacts beyond those expected to result from a federal carbon cap-and-trade program.

Conclusions and Recommendations on Policy Options to Mitigate Potential Emissions Leakage

In light of a political environment that strongly suggests emerging nation-wide support for a national carbon cap-and-trade program, and given that such a national program would be expected to eliminate or significantly mitigate potential emissions leakage, Staff recommends the following:

1. The RGGI participating states should monitor for emissions leakage and further evaluate the potential extent of projected leakage in the

context of recent state efforts to significantly expand investments in end-use energy efficiency programs. Further, the RGGI participating states should incorporate the evaluation criteria outlined above when evaluating the potential implementation of specific measures to mitigate leakage.

2. The RGGI participating states should prioritize the implementation of leakage mitigation measures with demonstrated effectiveness and short implementation time frames. Specifically, RGGI participating states should pursue a leakage mitigation approach of aggressive increases in investment in energy efficiency market transformation programs, and the implementation and expansion of complementary policies such as building energy codes and appliance and equipment efficiency standards that accelerate the deployment of end-use energy efficiency technologies and measures;

3. Because of their administrative complexities and challenges, as well as untested effectiveness as leakage mitigation strategies, Staff recommends that the policy options identified in Categories 2 and 3 – *i.e.*, a carbon procurement adder, carbon procurement emissions rate, emissions portfolio standard, and load-based cap – should not be prioritized for implementation at this time, absent compelling evidence based on leakage monitoring that emissions leakage has become a significant issue.

4. The RGGI participating states should support the State of New Jersey's investigation into potential Category 2 and 3 leakage mitigation options, as any measures enacted as a result of this proceeding could facilitate broader regional implementation of such measures in the RGGI region if end-use energy efficiency measures prove insufficient as a leakage mitigation approach, or action toward the implementation of a federal cap-and-trade program is significantly delayed.

I. Introduction

Background

On March 14, 2007, the Emissions Leakage Staff Working Group ("Staff") submitted to the RGGI Agency Heads a report: *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms* ("Initial Report"). In drafting the Initial Report, Staff took into account the provisions outlined in the December 20, 2005, RGGI Memorandum of Understanding (MOU) that, among other things, directed Staff to consider policy options to address potential emissions leakage. The Initial Report also reviewed wholesale electricity market dynamics that could drive or mitigate the potential for emissions leakage, and provided a detailed proposal for monitoring emissions leakage.

With the exception of the leakage monitoring proposal, the Initial Report did not make any policy recommendations, but instead provided a qualitative analysis of various policy options for mitigating potential emissions leakage as a starting point for the Agency Heads' consideration of this matter.

Stakeholder Process

Shortly after the submission of the Initial Report, Staff provided notice to RGGI stakeholders and the public of the report's availability on the RGGI website and solicited comments for a period of 60 days. In addition, on April 25, 2007, staff held a conference call with the stakeholders, prior to the end of the written comment period, to address questions about the report.[7]

The Final Report

The purpose of this report is to provide Staff's conclusions and recommendations with respect to: I) the modification of tracking systems in the three ISO regions to monitor potential emissions leakage; II) the current political momentum toward a national cap-and-trade program; and III) leakage mitigation policy options that should be prioritized for implementation at this time.

Staff's conclusions and final recommendations are based, in part, on additional feedback from Agency Heads, independent experts, the regional ISOs, and stakeholders.

II. Tracking Systems for Monitoring Emissions Leakage

Background

In the Initial Report, Staff concluded that it is essential to be able to track the environmental attributes associated with all the power being generated to serve load in the RGGI region, in order to monitor and quantify the extent of

[7] Stakeholder comments can be found on the RGGI website at http://www.rggi.org/emisleak_comments.htm.

potential emissions leakage.[8] Staff proposed specific recommendations for monitoring leakage that would require minor modifications of existing generation attribute tracking systems that are currently used in the region's electricity markets. Staff recommended the following:

1) Explore modifications to the existing generator attribute tracking systems in the region and the emerging tracking system currently under development by New York in order to, for each individual control area:

> (i) determine how much electricity is being used in a control area or partial control area subject to RGGI;
>
> (ii) determine the environmental attributes associated with the generation of electricity both inside a control area or partial control area subject to RGGI and in adjoining control areas;
>
> (iii) create generation attribute identifiers for "RGGI-affected unit," "unaffected small fossil fuel-fired RGGI region unit," and "RGGI region unit;"
>
> (iv) track net imports into NY-ISO, PJM, and ISO-NE from adjoining control areas and account for related environmental attributes;
>
> (v) infer net "imports" into the RGGI portion of PJM and account for related environmental attributes; and
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> (vi) generate data reports of "RGGI residual emissions mix," "unaffected small fossil fuel-fired RGGI-region unit emissions mix," and "RGGI emissions mix."

2) Urge PJM and ISO-New England to make the necessary modifications to the Generation Attributes Tracking System and Generation Information System, respectively, that will enable the collection of data and regional coordination among attribute tracking systems necessary to monitor regional emissions leakage;

3) Urge New York to coordinate with PJM and ISO-New England in order to include features that will enable the collection of the necessary data to monitor regional emissions leakage in the New York tracking system currently under development; and

4) Using the approach outlined in the Initial Report, begin monitoring prior to the start of the RGGI program to evaluate CO_2 emissions from non-RGGI generation in order to develop baseline data.[9]

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[8] *See* Section III of Initial Report at 11-26.
[9] *See* Initial Report at 25-26.

Status of Tracking Systems Modifications to Support RGGI

With the submittal of the Initial Report, Staff began pursuing discussions with the appropriate parties responsible for making modifications to the current tracking systems in both the New England and PJM control areas. Consequently, on November 16, 2007, the ISO-New England Participants Committee approved RGGI's monitoring proposals, thereby authorizing ISO-New England's Generation Information System (GIS) administrator to make the requested changes to its software platform.[10] A similar commitment by PJM's Generation Attribute Tracking System (GATS) administrator was also made in November 2007. The modifications necessary in both control areas are expected to be implemented by the end of the first quarter of 2008 to allow for tracking of calendar year 2008 baseline data. These two tracking systems cover nine out of the ten RGGI participating states.

In New York State, which has a distinct generator attribute tracking system currently administered by the Department of Public Service (NYDPS), efforts to automate its tracking system are currently under review by the NYDPS, the New York State Energy Research and Development Authority (NYSERDA), and the New York ISO.[11] The goal is to develop a compatible tracking system with the surrounding regions while still supporting current NYDPS environmental programs and policies. Implementation of a modified New York tracking system is currently scheduled for late 2008.

III. Political Momentum toward a National Carbon Cap-and-Trade Program

Background

In the Initial Report, Staff defined "emissions leakage" as a shift of electricity generation from capped sources subject to a regional program such as RGGI to generation sources not subject to RGGI that results in a net increase in emissions.[12] Staff explained that the implementation of a carbon cap on power plants is expected to increase the cost of electricity generation in the RGGI region. In a competitive power market, this may have the effect of shifting generation in the larger region to uncontrolled, and presumably cheaper, fossil fuel-fired generation not subject to a carbon cap. Staff noted that the concept of emissions leakage is, therefore, specific to a situation where a larger national program does not exist. Staff also noted the political momentum toward a national carbon cap-and-trade program and viewed the potential for emissions leakage as a near- to mid-term concern. In this section, Staff address the status

[10] Sections 2.1, 2.3, 2.5, 2.8, 5.3, GIS Appendix 1.1 (4) and (12), and GIS Appendix 2.4 (6) and (11) were modified to add the capability to produce reports related to RGGI leakage and the associated changes to how emissions data will be acquired for EPA-reporting generating units. The effective date for these modified rules is January 1, 2008. *See*, http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/geninfo_sys/operating/index.html

[11] *See generally*, Initial Report at Appendix II; Case 03-E-0188, Proceeding on Motion of the Commission Regarding Retail Renewable Portfolio Standard, Order of June 28, 2006; *see also* "Status Report on Implementation of the Renewable Portfolio Standard Program," August 9, 2007 at 10.

[12] *See* Initial Report at ES-1.

of the current political environment surrounding climate change and the apparent movement towards a national mandatory emissions reduction program.

A Snapshot of the Current Political Environment

According to the Pew Center on Global Climate Change, in 2007, there were more than 120 bills in Congress addressing climate change issues.[13] As of January 2008, there are 12 pieces of legislation pending in Congress that would establish cap-and-trade programs.[14]

Environmental organizations and members of the business community are urging Congress to develop climate change legislation. In a joint statement to the U.S. Congress, the United States Climate Action Partnership (USCAP), an alliance of major businesses and leading climate and environmental groups that have come together to call on the federal government to enact climate change legislation, urged the U.S. Congress to "enact a policy framework for mandatory reductions of greenhouse gas emissions from major emitting sectors, including large stationary sources, transportation, and energy use in commercial and residential buildings." [15] According to USCAP, the "cornerstone of this approach would be a cap-and-trade program."[16]

State utility regulators across the country are also becoming increasingly aware of the various options before Congress to regulate carbon dioxide emissions from electric generation facilities. In March 2007, the National Association of Regulatory Utility Commissions (NARUC), established a *Task Force on Climate Policy* (Task Force) to study how climate change policies being debated in Congress could impact the provision of retail electricity.[17] Since that time, the Task Force and other NARUC committees have passed resolutions regarding climate change, including a "Resolution on Implications of Climate Policy for Ratepayers and Public Utilities," and "Federal Climate Legislation and Cap-and-Trade Design Principles."[18]

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[13] Remarks by Eileen Claussen, President, Pew Center on Global Climate Change to U.S. EPA Senior Executive Service Meeting, July 13, 2007.
http://www.pewclimate.org/press_room/speech_transcripts/ec_epa

[14] See S. 309, (Sanders/Boxer); S. 485, (Kerry/Snowe); H.R. 620, (Oliver/Gilchrest); H.R.1590 (Waxman); S. 1766 (Bingaman-Specter); Udall-Petri (Draft, May 2007); S. 280 (Lieberman-McCain); S. 485 (Kerry-Snowe); S. 309 (Sanders-Boxer); S. 317 (Feinstein-Carper); S. 1168 (Alexander-Lieberman); and S. 2191 (Lieberman-Warner).

[15] Joint Statement of the United States Climate Action Partnership, January 19, 2007; http://www.us-cap.org/media/index.asp. A partial list of USCAP members includes: Alcoa, BP, Caterpillar, Chrysler, ConocoPhillips, Dow, Duke Energy, DuPont, Environmental Defense, Exelon, Ford, General Electric, General Motors, National Wildlife Federation, PepsiCo, PG&E, Shell, Siemens, World Resources Institute, and Xerox.

[16] *Id*.

[17] NARUC is an organization representing the State public service commissioners who regulate essential utility services, including electricity, throughout the country, and who are charged with protecting the public and ensuring that rates charged by regulated utilities are fair, just, and reasonable.

[18] See NARUC press release, "In Major Action, NARUC Supports Federal Climate Legislation, Spells Out Policy Options," November 14, 2007 (available at: http://www.naruc.org/News/default.cfm?pr=61).

In April 2007, the U.S. Supreme Court, in its ruling in Massachusetts v. EPA, found that carbon dioxide was a pollutant that could be regulated under the Clean Air Act.[19] The court ruled that the Environmental Protection Agency violated the Clean Air Act by improperly declining to regulate greenhouse gas emissions from new-vehicles.[20]

In May, the Department of Energy's National Energy Technology Laboratory (NETL) reported that coal-fired power plants in the construction pipeline fell to 121 from 151 in May 2007.[21] According to the NETL, eight plants were removed from the list because they were canceled, and nine because they were put on hold.[22]

In October 2007, the Kansas Department of Health and Environment denied a permit for two 700-megawatt coal-fired generation units proposed for construction in southwest Kansas by several electric cooperatives.[23] Despite a staff recommendation to issue the air permit, the Department Secretary indicated in a statement, that "it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health if we do nothing."[24] In making this decision, the Secretary also cited to the April 2007, U.S. Supreme Court ruling in Massachusetts v. EPA.[25]

In November 2007, nine members of the Midwestern Governors Association and the Canadian province of Manitoba formed the Midwestern Regional Greenhouse Gas Reduction Accord, an agreement that calls for the development of greenhouse gas emissions reduction targets and a carbon cap-and-trade system.[26]

In February 2008, three of the world's leading financial institutions announced the adoption of climate change guidelines for advisors and lenders to electric generation companies in the United States. The guidelines were the result of a nine-month effort to create an approach for evaluating and addressing carbon regulatory risks in the financing of electric power projects. The perceived need for these guidelines was driven by the risks faced by the power industry as

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[19] 549 U.S. 1438 (2007); *see also* "High Court Faults EPA Inaction on Emissions," Washington Post, Robert Barnes and Juliet Eilperin, April 3, 2007 at A01.
[20] *Id*.
[21] See Mark Clayton, "Pace of Coal-Power Boom Slackens," Christian Science Monitor, October 25, 2007.
[22] See Jeffrey Ball, "Wall Street Shows Skepticism Over Coal, Banks Push Utilities To Plan for Impact Of Emissions Caps," Wall Street Journal, February 4, 2008 at A6; Rebecca Smith, Stephen Power, and Jeffrey Ball, "After Washington Pulls Plug on FutureGen, Clean Coal Hopes Flicker," Wall Street Journal, February 2, 2008 at A7; Judy Pasternak, "Coal is No Longer on Front Burner," Los Angeles Times, January 18, 2008.
[23] Mathew Wald, "Citing Global Warming, Kansas Denies Plant Permit," New York Times, October 20, 2007; Susan Moran, "The Energy Challenge: Fight Against Coal Plants Draws Diverse Partners," New York Times, October 20, 2007; Brad Knickerbocker, "King Coal's Crown is Losing Some Luster," Christian Science Monitor, August 2, 2007.
[24] *Id*.
[25] *Id*.
[26] The members are the states of Wisconsin, Minnesota, Illinois, Iowa, Michigan, Kansas, and the Province of Manitoba. *See* http://www.midwesterngovernors.org/govenergynov.htm.

utilities, independent producers, regulators, lenders, and investors deal with the current uncertainties related to developing regional and national climate change policy.[27]

Conclusions and Recommendations

The current political environment strongly suggests a growing awareness and concern about climate change on the part of regulators, businesses, and other interest groups. This activity causes Staff to conclude that there is emerging national support for the development and implementation of a national carbon cap-and-trade program. In its Initial Report, Staff noted that the implementation of a national carbon cap-and-trade program "would in large part address the emissions leakage issue," and explained that:

> The implementation of a national CO_2 cap-and-trade program for the electric power sector that is equivalent to RGGI, or a scenario where RGGI sunsets once a national program is implemented, would obviate any potential for emissions leakage.[28]

Staff continues to advance this position, and for this reason recommends that the RGGI participating states prioritize the implementation of emissions leakage mitigation measures that have demonstrated effectiveness and that can be implemented relatively quickly, instead of more complex measures that would require greater implementation lead times and for which effectiveness has yet to be demonstrated.

IV. Evaluation of Emissions Leakage Mitigation Measures in RGGI Participating States.

On January 13, 2008, the State of New Jersey enacted legislation requiring the New Jersey Board of Public Utilities (BPU) to adopt, by July 1, 2009, rules establishing a greenhouse gas emissions portfolio standard (EPS) or another regulatory mechanism, to mitigate leakage, applicable to all electric power suppliers and basic generation service providers that provide electricity to customers within the State.[29] In response to this legislation, on March 18, 2008, the New Jersey BPU issued an order to convene a proceeding to evaluate emissions leakage mitigation measures.[30] That proceeding will, in part, gather relevant information about an EPS and other leakage mitigation measures by conducting a public stakeholder process, to be followed by a public hearing, on the selection of appropriate leakage mitigation policies and practices.

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[27] See Citicorp press release, "Leading Wall Street Banks Establish The Carbon Principles," available at http://www.citigroup.com/citigroup/press/2008/080204a.htm.
[28] *See* Initial Report at note 19 and accompanying text.
[29] See P.L. 2007, c.340 supplements Title 26 of the Revised Statutes, and amends the Electric Discount and Energy Competition Act, P .L.1999, c.23, N.J.S.A. 48:3-49 et seq.
[30] See BPU Docket No. EO08030150, "In The Matter of A Greenhouse Gas Emissions Portfolio Standard and Other Regulatory Mechanisms to Mitigate Leakage."

V. Policy Recommendations For Addressing Potential Emissions Leakage

Background

In its Initial Report, Staff identified three broad categories of policies for addressing potential emissions leakage. These categories included:

(1) Policies that indirectly address carbon emissions by reducing electricity demand;

(2) Policies that directly address, but do not cap, carbon emissions related to electricity use; and

(3) Policies that cap carbon emissions related to electricity use.[31]

Evaluation Criteria

Staff also identified criteria that should be considered when evaluating each category of policy options. Staff recommended that States consider the extent to which each option:

1. Accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner;

2. Maintains and/or enhances electric system reliability;

3. Ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region;

4. Remains relevant even after a mandatory federal greenhouse gas reduction policy is in place;

5. Encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity; and

6. Is compatible with other energy and environmental policies that address the end-use of electricity.[32]

Subsequent to the release of the Initial Report, Agency Heads directed Staff to also consider the following additional evaluation criteria:

7. Policy development and implementation time frame; and

8. Significant administrative hurdles and considerations.[33]

Below, Staff evaluates each potential leakage mitigation mechanism against these criteria.

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[31] For a discussion of all three categories of policies, *see* Initial Report at 26-44.
[32] *Id*. at 2-3.
[33] Comments from Agency Heads, Baltimore, Maryland, June 11-12, 2007.

Category 1 - Policies That Reduce Electricity Demand

In the Initial Report, Staff recommended a package of policies that RGGI participating states could implement to reduce electricity demand in the RGGI region as a means of mitigating potential emissions leakage.[34] These measures included:

1. Maximization of RGGI allowance allocation dedicated to support end-use energy efficiency;

2. Implementation of energy efficiency portfolio standards;

3. Harmonization across the RGGI region of the most up-to-date building energy codes and standards for commercial and residential buildings;

4. Harmonization across the RGGI region of the most up-to-date appliance and equipment energy efficiency standards; and

5. Development and implementation of policies and market incentives to reduce market barriers to combined heat and power (CHP) and clean distributed generation.

Criterion 1 -- *Accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner*

In the Initial Report, Staff noted the results of the energy sector modeling conducted on behalf of the RGGI Staff Working Group (SWG), which indicated that aggressive reduction of electricity demand in the RGGI region would lower RGGI CO_2 compliance costs and significantly reduce projected emissions leakage. The modeling evaluated a high-energy efficiency scenario, which indicated that an 8.8% reduction in 2021 electricity demand in the RGGI region, relative to projected business-as-usual demand, would result in a significant reduction in CO_2 allowance prices and prevent an incremental increase in power imports and emissions leakage.[35] In general, the modeling conducted on behalf of the SWG consistently showed that electricity demand was a key variable impacting CO_2 allowance prices and that lower allowance prices resulted in lower projected emissions leakage.

The policy options in Category 1 are designed to reduce electricity demand, and therefore can be expected, in turn, to help avoid emissions leakage.[36] Policies and programs that reduce electricity demand can be

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[34] For a detailed discussion of Category-1 policies, including policy strengths and effectiveness, and challenges and implementation issues, see Initial Report at 28-34.

[35] See ICF, "Updated Reference, RGGI Package and Sensitivities," September 21, 2005 (available at http://www.rggi.org/docs/ipm_modeling_results_9_21_05.ppt).

[36] With the exception of the discussion of an "energy efficiency portfolio standard" under Criterion 8, below, the following discussion does not differentiate between these various policies. For a

expected to reduce the demand for fossil fuel-fired electric generation, and thus reduces demand for CO_2 allowances and allowance prices. This in turn reduces the generation cost differential imposed on RGGI-affected generation units relative to generation units that are not subject to the RGGI cap, reducing the economic driver of emissions leakage. In addition, to the degree that overall electricity demand in the RGGI region is reduced, the demand for electricity generation not subject to the RGGI cap will also be reduced, as well.

Improving electricity end-use efficiency, achieved through the portfolio of policies listed above, would provide a significant low-cost means of avoiding CO_2 emissions. Energy efficiency can be deployed faster and typically at lower cost than supply-side options, such as the construction of new central-station electric generation facilities.[37] In addition, end-use energy efficiency investments typically provide net economic benefits to ratepayers through bill savings, reductions in the need for transmission and distribution investment, and reductions in wholesale electricity prices, especially during peak demand periods.

Revenue from the auction or sale of CO_2 allowances could significantly support expanded investment in end-use energy efficiency. Tables 1 and 2 below provide an overview of the relative increase in state per capita spending for energy efficiency programs that could be realized through an auctioning of 25 percent and 100 percent, respectively, of the CO_2 emissions budgets of RGGI participating states.

As illustrated by Table 1, if each RGGI participating state auctioned a minimum of 25 percent of its initial annual CO_2 emissions budget and utilized the revenue for additional investment in end-use energy efficiency programs, it would increase current per capita investment by each state between 3 percent to 111 percent, based upon a \$2.00 allowance price, or by 4 percent to 166 percent, if each allowance sold at \$3.00.[38]

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more detailed review of each policy in Category 1, *see* Appendix III; *see also* Initial Report at 27-31 and Appendix IV.

[37] *The Power to Reduce CO_2 Emissions*: *The Full Portfolio*, Electric Power Research Institute (EPRI) Discussion Paper, August 2007.

[38] The RGGI Memorandum of Understanding (MOU) allows each RGGI signatory state to decide how to allocate its allowances provided that:

> Each Signatory State agrees that 25% of the allowances will be allocated for a consumer benefit or strategic energy purpose. Consumer benefit or strategic energy purposes include the use of the allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon-emitting energy technologies, to stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or to fund administration of this Program.

RGGI MOU at Section 2G(1).

Table 1. Per Capita Increases in End-Use Energy Efficiency Spending Available with 25 Percent RGGI Allowance Auction

State	Current $ per capita spent on energy efficiency	Allowances @ $2.00	Per capita $ Increase	Per capita % Increase	Allowances @ $3.00	Per capita $ Increase	Per capita % Increase
CT	$27.57	$5,347,518	$1.53	6%	$8,021,277	$2.29	8%
DE[39]	$4.00	$3,779,894	$4.43	111%	$5,669,840	$6.64	166%
ME	$8.25	$2,974,451	$2.25	27%	$4,461,677	$3.38	41%
MD	$17.95	$18,751,992	$3.34	19%	$28,127,987	$5.01	28%
MA	$18.75	$13,330,102	$2.07	11%	$19,995,153	$3.11	17%
NH	$12.60	$4,310,230	$3.28	26%	$6,465,345	$4.92	39%
NJ	$16.10	$11,446,365	$1.32	8%	$17,169,548	$1.98	12%
NY	$16.89	$32,155,403	$1.67	10%	$48,223,104	$2.50	15%
RI	$13.38	$1,329,620	$1.25	9%	$1,994,429	$1.87	14%
VT	$38.46	$612,915	$0.98	3%	$919,373	$1.47	4%

To illustrate further, Table 2 provides a range of increased per capita end-use energy efficiency program spending that could result from the auction of 100 percent of each RGGI participating state's initial annual CO_2 emissions budget. Assuming an allowance price of $2.00, per capita spending on end-use energy efficiency programs could be increased by 10 percent to 443 percent; based on a $3.00 allowance price, or by 15 percent to 664 percent if allowances sold at $3.00.

Table 2. Per Capita Increases in End-Use Energy Efficiency Spending Available with 100 Percent RGGI Allowance Auction

			If allowances cost $2 per ton		If allowances cost $3 per ton	
State	Current $ per capita spent on energy efficiency		$ Increase in per capita energy efficiency investment	% Increase in per capita energy efficiency investment	$ Increase in per capita energy efficiency investment	% Increase in per capita energy efficiency investment
CT	$27.57		$6.10	22%	$9.15	33%
DE	$4.00		$17.72	443%	$26.57	664%
ME	$8.25		$9.00	109%	$13.50	164%
MD	$17.95		$13.36	74%	$20.04	112%
MA	$18.75		$8.28	44%	$12.42	66%
NH	$12.60		$13.11	104%	$19.67	156%
NJ	$16.10		$5.27	33%	$7.91	49%
NY	$16.89		$6.66	39%	$9.99	59%
RI	$13.38		$4.98	37%	$7.47	56%
VT	$38.46		$3.97	10%	$5.89	15%

[39] While Delaware is included in this table, its SBC fund has previously been restricted to investments in renewable resources only. However, in 2006, Delaware's General Assembly appropriated general fund dollars for efficiency programs equaling approximately $4.00 per capita. In 2007, Delaware created the Sustainable Energy Utility (SEU) that is charged with providing efficiency services using SBC dollars and bond financing, which may be supplemented with RGGI revenues as noted.

Such an approach would be subject to a positive feedback signal. If allowance prices increased, additional revenue would be available for use in implementing more aggressive end-use energy efficiency deployment efforts to moderate allowance prices.

Assuming an indicative performance level of 250 kWhs of electricity initially saved for every dollar invested, the use of revenue received through a 100 percent auction of RGGI CO_2 allowances could result in a 1.3 percent reduction in projected regional electricity use in 2012, a 2.4 percent reduction in 2015, and a 5.1 percent reduction in 2021.[40] Based on electricity simulation modeling conducted to support the development of the RGGI program, such a level of demand reduction would have a significant impact in lowering allowance prices and reducing projected emissions leakage.[41]

Criterion 2 -- *Maintains and/or enhances electric system reliability*

The Initial Report discussed the potential effects that proposed leakage mitigation measures might have on electric system reliability.[42] Staff concluded at that time, and still maintains, that all three categories of policy options would have no significant impact on electricity system reliability since none of the policies considered places a direct compliance obligation on electric generation units. Policies evaluated would either affect demand for electricity or place specific carbon requirements on retail electricity providers, *i.e.*, load serving entities.[43]

It should also be noted that in cases where an electric system experiences reliability challenges, end-use energy efficiency can produce significant positive system benefits.[44]

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[40] Assumes an indicative annual program performance yield of $250 invested per annual MWh of electricity saved, based on a survey of recent energy efficiency program performance in Maine, Massachusetts, New Jersey, New York, and Vermont. Allowance prices and load projections from RGGI October 2006 IPM energy modeling runs.
[41] *See* ICF, "Updated Reference, RGGI Package and Sensitivities," September 21, 2005 (available at: http://www.rggi.org/docs/ipm_modeling_results_9_21_05.ppt).
[42] *See* Initial Report at pp. 42-44.
[43] *Id*. at 42. Staff further noted that even policies that place a modest compliance obligation on generation units are not expected to impact system reliability. Ensuring system reliability can be understood as an exception to the least-cost economic dispatch model. Generator costs are included in the bid prices that generators submit to the wholesale electricity market, and generation units are then dispatched on their relative economic merits: the cheapest units are dispatched first; then more expensive units follow. However, system reliability is ensured by allowing units that are required for reliability purposes to be dispatched out of economic merit order.
[44] In 2002, the American Council for an Energy-Efficient Economy (ACEEE) reviewed the potentially positive effects on system reliability of energy efficiency investment during California's electric system crisis. According to ACEEE, "[t]hese circumstances led to a strongly renewed interest in "demand-side" program strategies as an important category of resources that could help alleviate these electric system reliability problems." See Kushler, Vine and York, "Energy Efficiency and Electric System Reliability: A Look at Reliability-Focused Energy Efficiency Programs Used to Help Address the Electricity Crisis of 2001," ACEEE, 2002, at 3 (available at http://aceee.org/pubs/u021full.pdf). ACEEE further noted that there are "multiple policy objectives

Criterion 3 -- *Ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region*

In the Initial Report, Staff provided an overview and assessment of the legal considerations involving implementation of policy measures to address emissions leakage.[45] Staff noted, among other things, that states cannot purposely discriminate against interstate commerce through the differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter. Because energy efficiency polices affect the manner in which RGGI-region electricity consumers use electricity, as opposed to how electricity generators supply electricity to the wholesale market, this category of policies makes no distinction between electric power generated within the RGGI region and electric power generated outside the region. Staff, therefore, concludes that these policies ensure that power generated outside the region is not treated any differently than the power generated within the RGGI region.

Criterion 4 -- *Remains relevant even after a mandatory federal greenhouse gas emissions reduction policy is in place*

End-use energy efficiency policies and programs can be expected to remain relevant and play a significant role in supporting the successful implementation of a federal carbon cap-and-trade program. As long as carbon-abatement technology is not fully commercialized or remains relatively more expensive than CO_2 emissions avoidance measures, aggressive deployment of end-use energy efficiency technologies and measures will continue to serve a significant complementary cost-containment role for a federal cap-and-trade program. In recognizing the current lack of commercialized CO_2 emissions abatement and sequestration technology, industry leaders, as well as environmental advocates, emphasize the importance of policy mechanisms that promote end-use energy efficiency and demand-side management strategies, as well as development of low- and non-emitting generation technologies, as a means of bridging the gap until carbon emissions abatement and carbon capture technologies are fully commercialized and economically competitive.[46]

The design of the RGGI cap-and-trade program acknowledges the need for the integration of both a supply-side and demand-side focus in order to reduce sectoral emissions at the overall lowest cost, and applies such an approach through the auctioning of allowances and the use of allowance revenue to reduce electricity demand. Staff believes that the expansion of the deployment of end-use energy efficiency policies and programs will remain highly relevant once a federal carbon cap-and-trade program is implemented. These policies will remain crucial in order to address market failures, moderate allowance prices, and reduce ratepayer impacts from a federal program.

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for these programs, such as avoiding blackouts, saving energy, reducing customer bills, providing environmental benefits, reducing the market power of suppliers, etc." *Id*.

[45] *See* Initial Report at Appendix III

[46] For a more detailed discussion of this point, see "The Availability of Carbon Abatement and Sequestration Technologies" at Appendix II; *see also* Appendix IV for a description of current renewable portfolio standards in the RGGI region.

In its comments on the Initial Report, World Resources Institute (WRI) recognized the ability of end-use energy efficiency to lower the price differential between generation subject to the RGGI cap and other generation serving load within the region, and that such a design approach should inform a federal program. WRI stated:

> RGGI may have an opportunity to pioneer methods for integrating energy efficiency policies with a cap-and-trade system, and demonstrate the link between energy efficiency and reduced compliance costs. Even where the effect is small, this would have potentially great value as a model for national level programs.[47]

In addition, WRI contends that energy efficiency programs "will help boost economic output per unit of energy consumed" which can give RGGI participating states a "head start in positioning their economies to be competitive in a world with carbon constraints." [48]

Energy savings from end-use efficiency investments also assist in compliance with other local and regional environmental and health goals, such as national ambient air quality standards, which will undoubtedly remain in place after the implementation of a federal carbon cap-and-trade program. Reductions in energy use not only avoid carbon emissions, but avoid local emissions of other criteria pollutants associated with the combustion of fossil fuel, such as sulfur dioxide, oxides of nitrogen, and fine particulates.

Staff therefore concludes that the portfolio of end-use energy efficiency policies and measures being proposed above will remain highly relevant after the inception of a federal carbon cap-and-trade program.

Criterion 5 -- *Encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity*

By definition, the implementation of policies and programs that accelerate the deployment of end-use energy efficiency technologies and measures will encourage more efficient end-use of electricity. However, one cannot conclude that these policies will necessarily improve carbon efficiency in electric generation. Although increasing end-use energy efficiency can be expected to avoid carbon emissions, thereby lowering allowance prices and cap-and-trade program compliance costs, it is the imposition of an emissions cap and the price signal associated with the costs of complying with the cap that would result in improved carbon efficiency of electricity generation.

[47] WRI at 9.
[48] *Id*. at 10.

Criterion 6 -- *Is compatible with other energy and environmental policies that address the end-use of electricity*

Implementation of a portfolio of end-use energy efficiency policies and increased investment in end-use energy efficiency market transformation programs would build upon and leverage the work already underway in the RGGI participating states to reduce electricity use and demand. The infrastructure to support an expansion of end-use energy efficiency programs is already in place in most of the RGGI states. This should shorten the lead-time for design and implementation for Category-1 policies and measures. Additionally, because many of the RGGI States are already in the process of accelerating the deployment of energy efficiency programs, this set of policies is consistent with such efforts.

Criterion 7 -- *Policy development and implementation time frame*

As discussed previously, Staff concludes that the likelihood of the adoption of a federal carbon cap-and-trade program in the next few years has substantially increased and therefore views potential emissions leakage as a near- to mid-term issue. Consequently, Staff concludes that measures that can be implemented relatively quickly, such as the expansion of existing end-use energy efficiency programs and policies, should be given priority over more complex measures with significantly greater implementation lead times.

Numerous policies that reduce electricity use and demand are already being implemented across the RGGI region. While the aggressiveness and scope of specific policies and standards vary significantly from state to state, the expansion of investment to support deployment and implementation of additional end-use energy efficiency policies and standards should not require significant lead-time compared with the other leakage mitigation policies examined in this report.

Criterion 8 -- *Significant administrative and implementation considerations*

As noted above, all RGGI participating states have existing energy efficiency market transformation programs. RGGI participating states also have building energy codes and standards for commercial and residential buildings, appliance and equipment energy efficiency standards, and policies and market incentives to reduce market barriers to combined heat and power (CHP) and other clean distributed generation applications.[49]

In large part, the policies being recommended under Category 1 would leverage existing programs and expand investments in energy efficiency across the RGGI participating states. Because most RGGI participating states have already developed such market transformation programs, working within existing programs that states have found to be successful and cost-effective would largely avoid the administrative effort associated with developing new programs.

[49] These policies are discussed at Appendix III; *see also* Initial Report at 27- 31 and Appendix IV.

One exception, however – the development of an energy efficiency portfolio standard (EEPS or Efficiency Standard) – could present a significant administrative undertaking. Several RGGI states, including Connecticut, New Jersey, New York, and Vermont, have established targets for reducing energy use. New York is currently involved in regulatory proceedings to develop energy efficiency portfolio standards for regulated utilities.[50]

An EEPS is a market-based mechanism that mandates energy efficiency improvements by requiring utilities to meet targets for electric (and/or natural gas) energy savings. As recognized in the Initial Report, the primary advantage of an efficiency standard is that it would allow states to achieve economies of scale due to state-wide targets that allow energy providers to “aggregate savings across multiple end-uses and sectors to meet the overall energy savings goal in the most cost-effective manner.”[51]

While efficiency standards can be developed in a number of different ways and within different regulatory frameworks, both legislative authorization and associated administrative processes would likely be necessary in states that have not yet adopted such mechanisms.[52] It is reasonable to expect that such proceedings would involve significant time and regulatory resources.

Conclusions for Category-I Policy Options

The current political environment strongly suggests that there is emerging nationwide support of the development and implementation of a national carbon cap-and-trade program. Such a program can be expected to eliminate or significantly minimize the potential for emissions leakage. Staff recommends that RGGI participating states prioritize leakage mitigation measures that can be implemented relatively quickly, relative to more complex measures that would require greater implementation lead times. Policies that reduce electricity demand are already being implemented across the RGGI region. While the aggressiveness and scope of such policies and programs varies significantly from state to state, expansion of investment to support the accelerated deployment of end-use energy efficiency technologies and measures[53] and the implementation of additional end-use energy efficiency policies, programs, and standards should not require significant lead-times.

[50] On May 16, 2007, the New York Public Service Commission issued an Order instituting a proceeding to establish a New York State energy efficiency portfolio standard. This effort is to be coordinated with the existing SBC programs already in place. The goal of the efficiency standard is to reduce electric usage 15% from forecasted levels by 2015.
[51] *See* Initial Report at 28.
[52] Eight of the RGGI participating states have restructured electric utilities, while Vermont and part of New Hampshire’s electric industries continue to be regulated under a traditional, integrated cost-of-service regulatory model.
[53] Including policies to support the implementation of high-efficiency, low-emission CHP applications and other clean distributed generation.

Category 2 - Carbon Adder and Emissions Rate Mechanisms

Background

The second category of policies described in the Initial Report would directly address carbon emissions. These policies include:

(1) *Carbon procurement adder* - an analytical tool that requires an LSE planning its electricity supply resource acquisitions to incorporate a "shadow price" for carbon emissions into its financial analysis of different investment options;

(2) *Carbon procurement emissions rate* - a limit placed on the emissions rate of power supplied to an LSE through a long-term power purchase agreement; and

(3) *Emissions portfolio standard* - a policy mechanism that would require an LSE to meet an average, output-based emissions standard (lbs. CO_2/MWh) for the portfolio of supply resources the LSE uses to provide retail electricity.

Criterion 1 -- *Accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner*

1. *Carbon procurement adder*

A carbon procurement adder is an analytical tool that requires an LSE planning its resource acquisitions to incorporate a "shadow price" for carbon emissions into its financial analysis of different investment options. The major benefit of developing and implementing a carbon procurement adder is that it internalizes future carbon regulatory risk into a company's planning process, and therefore provides utilities with a mechanism with which to evaluate resource supply options, while addressing potential future carbon constraints. Such a mechanism has been implemented by the California Public Utilities Commission.[54]

A carbon procurement adder would work best for LSEs operating in a traditionally regulated – or as in California, re-regulated – environment where utility regulatory commissions continue to engage LSEs in a procurement planning review process known in many states as "integrated resource planning."[55] A carbon procurement adder is also ideally suited to the evaluation of plant-specific power purchase agreements, since the environmental and dispatch characteristics of supply resources are more easily accounted for if subject to a plant-specific power purchase agreement.

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[54] *See* California Public Utilities Commission Decision 04-12-048, December 16, 2004. This decision recognized the need for a "GHG adder" when evaluating fossil and renewable generation bids…." *Id*. at 3-4.

[55] *See, e.g.*, Galen Barbose, et al., "Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans," Lawrence Berkeley National Laboratory, March 2008 (available at http://eetd.lbl.gov/ea/emp/rplan-pubs.html).

By contrast, in restructured states, such as the majority of RGGI participating states, implementation of a carbon procurement adder would likely be a greater challenge. In these states, the majority of power supplied to the public is procured from undifferentiated sources in the wholesale electricity market. In some states, generation companies may bid to serve a portion of an LSE's electricity load under a multi-year contract. However, most contacts typically do not specify the generation facility from which the electricity will be supplied, instead relying on resources available in the regional wholesale market to deliver a specified amount of energy and capacity.

A carbon procurement adder would be a greater challenge to implement in such a restructured market, absent significant modification to current procurement processes. Power providers that bid to serve LSE load would need to provide resources not only on a cost-competitive basis, they would also need to be able to determine and account for the environmental attributes associated with the power they propose to supply. This would require the use of existing generator attribute tracking systems to allow market participants and regulators to infer the environmental attributes associated with the power being offered. In many cases, such a determination may not be possible, such as in a scenario where the winning bidder has not specified the specific facilities from which the power will be supplied. Even in scenarios where specific facilities are identified, suppliers may vary output from individual facilities on the basis of wholesale market economics, and in some cases may procure power from other suppliers to serve the LSE's load if such a strategy maximizes financial returns. As a result, such a mechanism would likely need to infer the environmental attributes for a mix of hypothetical power to be supplied, and might not impact actual system dispatch.

As a leakage mitigation option, a carbon procurement adder that is equivalent to the RGGI CO_2 allowance price could be implemented. This would remove any financial incentive for an LSE to change its procurement practices to engage in plant-specific power purchase agreements with generators not subject to the RGGI program, in an effort to evade the wholesale price adder resulting from RGGI compliance. However, such a mechanism, due to the challenges outlined above, would likely not significantly impact the dispatch of the regional power system.

A carbon procurement adder would present a challenge for use as a planning tool to evaluate the carbon intensity of spot market power purchases, which would be a mix of system power including both low-emitting and high-emitting units. However, with the use of existing generator attribute tracking systems, an environmental profile for the system mix could be established. While specific LSE purchases of spot market power would not directly impact the carbon intensity of this power, when managing their power procurement, LSEs required to incorporate a carbon procurement adder would still need to account for the carbon intensity of spot-market power when making their purchasing decisions and comparing spot market purchases with other supply options, including end-use energy efficiency resources and demand-side management. To the degree that all LSEs in a control area were subject to similar purchase requirements, the overall carbon intensity of the spot-market would likely be affected. However, Staff notes that such geographic coverage would not be possible in the PJM control area, the area of primary concern with regard to potential emissions leakage.

It should also be noted that a carbon procurement adder would only indirectly impact the dispatch of generators in the region, as generators would face no direct carbon compliance obligation or related compliance cost adder. Theoretically, a carbon adder would, therefore, not preclude emissions leakage due to a real-time re-dispatch of the regional power system due to a RGGI compliance cost adder.[56]

Staff also notes that energy supply purchases for an LSE portfolio developed pursuant to a carbon procurement adder would likely increase the cost of supply resources to reflect the cost associated with more expensive, lower-carbon-emitting generation sources. Such a policy option could have significant ratepayer impacts.

2. <u>*Carbon procurement emissions rate*</u>

A carbon procurement emissions rate is a limit that is placed on the emissions rate associated with power supplied to an LSE through a long-term power purchase agreement. This policy would require all long-term power purchases to meet a specific lbs. CO_2/MWh emission rate. No power supplied through bilateral contracts with suppliers could exceed this emissions rate.[57]

As an emissions leakage mitigation option, a carbon procurement emission rate mechanism would apply to all new, long-term power supply contracts. It could be based on the emissions rate for a certain class of technology, as was the case in recent a recent California PUC decision,[58] or on another measure, such as the average emissions rate achieved by all or some subset of a category of generation units.

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[56] Staff also noted in the Initial Report, that "[t]heoretically, such a procurement adder also might not impact system dispatch at all if the chosen "economic" resource, inclusive of carbon costs, remained the same as the resource chosen without the procurement adder. The dollar value of the adder would therefore be a key variable that could affect the efficacy of this policy as a leakage mitigation strategy." *See* Initial Report at ES-8.

[57] *See* California Public Utilities Commission Decision 07-01-039, Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework Rulemaking 06-04-009 and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, January 25, 2007. Under this order, California adopted an "interim greenhouse gas (GHG) emissions performance standard for new long-term financial commitments to baseload generation undertaken by all load-serving entities (LSEs)," consistent with Senate Bill (SB) 1368 (Stats. 2006, ch. 598), intended to serve as "a near-term bridge" until an enforceable greenhouse gas emissions limit applicable to LSEs is established and in operation. SB 1368 establishes a minimum performance requirement for any long-term financial commitment for baseload generation that will be supplying power to California ratepayers. The new law establishes that the greenhouse gas emissions rates for these facilities must be no higher than the greenhouse gas emissions rate of a combined-cycle gas turbine (CCGT) power plant. *See* Initial Report at note 52 and accompanying text.

[58] *Id*.

Unlike an emissions portfolio standard, discussed below, a carbon procurement emissions rate would be tied to the bundled electricity commodity, rather than an unbundled emissions attribute. It would therefore directly impact dispatch of power plants, and could not be avoided through the practice known as “attribute shuffling.”[59] However, such a mechanism could be subject to a related dynamic, referred to as “contract shuffling.” In a market where not all electricity sales are subject to a carbon procurement emissions rate, it is possible for buyers and sellers to "shuffle" contracts:

> A rule that assigns carbon attributes solely on the basis of power units assigned to a sale in a bilateral contract risks under counting the actual carbon contribution associated with the purchase in question. This is because it would be advantageous to sellers to contractually assign clean power to export sales into the RGGI region, while increasing carbon intensive power assigned to non-RGGI sales, without necessarily improving the generator’s emission profile at all.[60]

If contract shuffling were allowed to occur, then an LSE could potentially comply with a carbon procurement emissions rate without impacting the emissions profile of the regional power system.

Because a carbon procurement emissions rate would be tied to the bundled electricity commodity, one significant shortcoming of this policy is that it is not suited to addressing power purchases from the spot market. The effectiveness of a carbon procurement emissions rate, therefore, would be compromised to the degree that procurement practices focus on spot market purchases. Furthermore, where long-term power purchase agreements are not mandated, a carbon procurement emissions rate could serve as a disincentive for entering into long-term power purchase agreements.

3. *Emissions portfolio standard*

An emissions portfolio standard (EPS) is a policy mechanism that would require an LSE to meet an average output-based emissions standard (lbs. CO_2/MWh) for the portfolio of supply resources the LSE uses to provide retail electricity. Because it uses an average output-based standard, this mechanism could be adapted to incorporate demand-side resources (*i.e.*, end-use energy efficiency and demand-side management) along with supply-side resources as compliance measures.[61]

An EPS would impose a market signal upon LSEs that lower-emitting generation is a valuable commodity. However, for purposes of mitigating emissions leakage, an EPS would not necessarily address the cost differential between RGGI-affected units and those units not subject to the RGGI program.

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[59] Attribute shuffling is discussed below in this subsection.
[60] Cowart, R., “Addressing Leakage in a Cap-and-Trade System: Treating Imports as Sources,” Regulatory Assistance Project, April 2006 at 6.
[61] For example, energy efficiency resources procured by an LSE could be credited with an emissions rate of zero and considered as part of an LSE’s overall supply resource when determining the average emissions rate for the total electricity supplied by the LSE.

To ensure that this differential is properly addressed, it would be necessary to integrate the relationship between (1) the $/MWh EPS compliance cost faced by the LSE; and (2) the RGGI $/MWh compliance cost adder incorporated by electric generators into bids into the wholesale electricity market; and (3) ensure that the LSE market signal flowed through to a comparable market signal to electric generators that counterbalanced the RGGI compliance cost adder incorporated by RGGI-affected generators into wholesale market bids. It is unclear to what extent such an integrated market signal might be achieved, and, by extension, whether such a mechanism would significantly impact power system dispatch. As an EPS would not place a direct compliance obligation on electric generators, it might not be expected to affect real-time functioning of the electricity market, and thus might not preclude the possibility of emissions leakage due to a re-dispatch of the regional power system due to a RGGI compliance cost adder.

However, since an EPS imposes procurement requirements on LSEs, this policy could be expected to affect generation dispatch to the degree that all LSEs in an ISO market region were required to comply with the policy. Staff notes that such an implementation scenario would not be possible in the PJM control area.

Despite certain positive design aspects, an EPS has several significant shortcomings that should be noted. First, while an EPS would limit the carbon intensity of an LSE's supply portfolio by holding an LSE to a portfolio-average lbs. CO_2/MWh standard, the electricity demand within an LSE's service territory could increase. In response, an LSE could meet this increased demand by providing more energy while still meeting the lbs. CO_2/MWh standard under an EPS. Even though the LSE continued to meet the standard, the absolute emissions associated with its portfolio would increase unless the emissions rate requirement was periodically adjusted to account for load growth.

A second major shortcoming and implementation challenge associated with an EPS is the question of how to address the potential for "attribute shuffling". An EPS would likely be implemented using an environmental attribute-based credit system that separates the generation attributes from the electricity commodity. This could be problematic in an "open" system that includes both regulated and unregulated regions. An EPS could potentially allow an LSE to purchase environmental attributes from low-emitting generation without changing its power procurement practices. In such a scenario, an LSE could comply with the emissions standard requirement without impacting the dispatch of generation, and related emissions, in the region as a whole.

This dynamic points out the key difference between the use of attribute credit systems used for determining compliance with renewable portfolio standards and their use for determining compliance with an EPS. Renewable portfolio standards, with a few notable exceptions, typically require a very significant increase in installed renewable energy capacity and generation in order to meet the requirement. As a result, the system starts with a significant market shortfall of renewable energy attributes (*i.e.*, renewable energy credits). This shortfall creates a significant attribute credit price that supports the construction of new renewable energy capacity.

This would likely not be the case for an attribute credit-based EPS system implemented to address emissions leakage in the RGGI region, described as an "open" system. An "open" system addressing emissions leakage would be implemented in a broader market, in which the regulated region made up only a subset of that market. Such a system would likely have a surplus of low emissions attribute credits, because generation in the broader market would exceed that needed to meet electricity load in the regulated region. As a result, LSEs in the regulated region could purchase "excess" low-emissions attributes without significantly impacting the dispatch (and emissions) of the larger power system.

Due to the surplus of low-emissions attribute credits, the LSE $/MWh compliance cost (and the related economic value assumed to be provided to low-emitting generation) would likely be lower than the $/MWh RGGI carbon compliance cost adder faced by RGGI-affected electric generators. This could allow for potential emissions leakage, based on a continued generation cost differential between electric generators subject to RGGI in relation to non-affected generators, even though the LSE is demonstrating compliance with the emissions portfolio standard.

This would not happen in a "closed" system where the full geographic region encompassing a control area is regulated under the EPS mechanism. In such a scenario, an emissions rate that was set at the historic level for that control area would not allow a re-dispatch of the system that resulted in a higher emissions rate, since there would be no "surplus" low-emissions attributes available to the regulated system. However, Staff notes that the PJM control area would constitute an "open system" implementation scenario. Thus, the issue of the geographic scope of regulatory coverage – the issue that initially resulted in concern about potential emissions leakage under RGGI – could also potentially undermine the effectiveness of an EPS designed to mitigate emissions leakage.

Preventing attribute shuffling would require the modification of an attribute-based system, and would apply a hybrid approach to determine program compliance that evaluated LSE "contract path" electricity transactions using ISO market settlement systems in combination with a generator attribute tracking system. Specific emissions attributes would be applied to LSE transactions where a specific generation plant, and its related emissions, could be identified. With the exception of those MWhs for which a plant-specific emissions attribute is allowed (such as plant-specific bilateral electricity purchases and renewable energy attribute credits), all other MWhs delivered to retail customers by an LSE would be assigned a residual mix emissions attribute. This LSE-specific residual mix emissions attribute would be the weighted average CO_2 emissions rate (lbs. CO_2/MWh) of all other generation serving load in the control area, after subtracting for the generation from those generation units for which LSEs in the regulated region were allowed to claim plant-specific emissions attributes.

Such an approach would necessitate the incorporation of significant additional program design complexity. However, such an approach would not guarantee program effectiveness in mitigating emissions leakage, as an EPS would place no direct compliance obligation on electric generators, and would therefore not preclude a re-dispatch of the power system in response to a RGGI compliance cost adder.

Staff also notes that determining the appropriate emissions rate to apply to individual LSEs subject to an EPS could be a contentious process. Determining LSE-specific emissions rate baselines would follow a similar hybrid contract path and attribute tracking approach as that described previously for addressing the attribute shuffling issue. Determining individual historic LSE emissions rate baselines would be complex, as it would likely require forensic analysis of historic LSE contract path transactions and the use of generator attribute tracking systems to determine the emissions related to those purchases. As a result, the application of a regional emissions rate requirement would be simpler, but could meet with resistance from LSEs that could demonstrate relatively lower portfolio carbon emissions rates relative to other LSEs.

Criterion 2* -- *Maintains and/or enhances system reliability

As discussed under the Category-1 policy options, a carbon procurement adder, carbon procurement emissions rate, and emissions portfolio standard would have no significant effect upon electricity system reliability because none of these policies would place a direct compliance obligation on electric generation units. Instead, these policies would either affect demand for electricity or place specific carbon requirements on LSEs.[62]

Criterion 3* -- *Ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region

In the Initial Report, Staff provided an overview and assessment of the legal considerations involving implementation of policy measures to address emissions leakage.[63] Staff noted, among other things, that states cannot purposely discriminate against interstate commerce through the differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter. Because these polices affect the manner in which RGGI-region LSEs acquire electricity supply and are neutral with regard to the location of electric generation providing such supply, this category of policies makes no distinction between electric power generated within the RGGI region and electric power generated outside the region. Staff, therefore, concludes that these policies ensure that power generated outside the region would not be treated any differently than the power generated within the RGGI region.

Criterion 4* -- *Remains relevant even after a mandatory federal greenhouse gas emissions reduction policy is in place

These three policies can be expected to remain relevant in a federal program for the same reasons that continued investment in energy efficiency will

[62] For more discussion, *see* Initial Report at 42-44.
[63] *See* Initial Report, Appendix III.

remain a relevant policy. To the extent that these policies further incent LSEs to invest in energy efficiency as a supply resource and avoid electricity demand growth that would result in an associated need for electric generation, they can be expected to lower the economic impact of a federal carbon cap-and-trade program on electricity ratepayers. However, such policies could be redundant to Category-I policies in such a context.

Criterion 5 -- *Encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity*

These policy options can be expected to encourage energy efficiency and/or carbon efficiency in the generation and end-use of electricity. By internalizing the cost of carbon in power planning and acquisition decisions, LSEs will better evaluate alternatives to carbon-intensive supply-side resources, such as cost-effective end-use energy efficiency resources. These policies will also favor LSE procurement of more energy-efficient fossil fuel-fired generation resources over those less efficient resources that emit greater amounts of carbon dioxide per unit of electricity output. However, some of the challenges to the development and effective implementation of these policies could limit their impact in significantly improving the system-wide carbon efficiency of generation across an entire ISO control area.

Criterion 6 -- *Compatibility with other energy and environmental policies that address the end-use of electricity*

The imposition of a carbon procurement adder, carbon procurement emissions rate, and emissions portfolio standard on an LSE will likely result in increased procurement of end-use energy efficiency resources in lieu of generation supply, provided that such policies incorporate explicit elements that acknowledge end-use energy efficiency resources as a “supply resource.”

Criterion 7 -- *Policy development and implementation time frame*

1. Carbon procurement adder

It is not entirely clear what time frame would be necessary for a state in the RGGI region to implement a carbon procurement adder, given factors such as potential need for legislative authority and the likelihood of significant administrative complexity associated with implementing such a mechanism in restructured electricity markets.

As noted in the Initial Report, this mechanism was implemented under existing authority by the California Public Utilities Commission as a portfolio management requirement for several of large utilities, a process that took approximately nine months.[64] California’s experience provides one example of a

[64] *See* Initial Report at note 48 and accompanying text; *see also* California Public Utilities Commission Decision 04-12-048, December 16, 2004. Filed April 1, 2004, and decided on December 20, 2004, the California case, which also involved issues other than the development of a carbon procurement adder (e.g., modifying resource procurement plans for several California utilities), nonetheless appeared to be a significant undertaking.

potential development timeframe, although development of such a policy in a restructured electricity market would likely require the incorporation of design complexities that might extend such a timeframe. In one of the two non-restructured states in the RGGI region, Vermont, there is legislation pending before the Vermont General Assembly that, if signed into law, would authorize the Vermont Public Service Board to develop a similar mechanism for utilities in Vermont.[65]

2. Carbon procurement emissions rate and emissions portfolio standard

As explained more fully below under Criterion 8, there is a similar lack of clarity with respect to the potential timeframe required to develop a carbon procurement emissions rate or an emissions portfolio standard mechanism. Even assuming legislative authority, the development of policy design details (*e.g.*, establishing the level of carbon procurement emissions rate, or the specific lbs. CO_2/MWh standard to apply to supply resource portfolios) could require potentially lengthy regulatory proceedings. Design elements intended to limit the potential for attribute shuffling and contract shuffling would add to program complexity and would limit LSE compliance options, which could lead to potentially contentious regulatory proceedings.

Criterion 8 -- *Significant administrative and implementation considerations*

1. Carbon procurement adder

The implementation of a carbon procurement adder could be expected to present significant administrative challenges in restructured electricity markets. There would be a greater challenge associated with evaluating the carbon intensity of undifferentiated system-power purchases from wholesale markets, which are made up of a mix of both low-emitting and high-emitting generation units. This would likely be compounded by the fact that many entities contracting to serve LSE load frequently do not know ahead of time the specific facilities from which supply will be provided.

2. Carbon procurement emissions rate and emissions portfolio standard

There are two significant administrative and implementation challenges associated with a carbon procurement emissions rate and emissions portfolio standard. The first is the need to sufficiently track generation attributes and incorporate design elements to prevent contract shuffling or attribute shuffling. The second is the need to establish the specific emissions rates for use with each policy.

As discussed above, in order to prevent attribute shuffling, Staff recognized the need to develop a hybrid tracking system that could overcome the limitations associated with using an attribute tracking system in an electric market like PJM that includes both RGGI-affected and other generation sources. This

[65] See Senate Bill S.350, "Energy Independence and Economic Prosperity" (available at http://www.leg.state.vt.us/database/status/summary.cfm).

modification would require the recognition, where possible, of a “contract path” for electricity transactions, using ISO market settlement systems in combination with a generator attribute tracking system. Such a system would need to limit the ability of an LSE to acquire plant-specific attribute credits unless the LSE had a plant-specific contract for the provision of electricity supply. Such a system would utilize a contract path tracking element for use in the assignment of plant-specific emissions attributes coupled with a generator attribute tracking system that applied a residual mix emissions attribute to all other power procured by the LSE. The development of such a system would be a significant undertaking.

Establishing specific emissions rates for use with each policy would also likely involve significant administrative effort. In setting these standards (i.e. the actual allowable emissions rate associated with a carbon procurement emissions rate, or the specific lbs. CO_2/MWh standard for an emissions portfolio standard), state regulatory processes would need to take into account the types of existing generation available to serve load in each state, the types of generation that could become available to serve load in each state, and desired emissions targets for each policy. Establishing the level of a carbon procurement emissions rate or the specific lbs. CO_2/MWh standard to apply to LSE supply resource portfolios would then likely need to be undertaken through rulemakings, which could be contentious and potentially lengthy.

<u>Conclusions for Category-2 Policy Options</u>

Each of the Category 2 policies comes with significant challenges. Furthermore, the effectiveness of each of these policies in mitigating emissions leakage is uncertain, and is dependent on the suitability of the market context in which each is used, the success of specific design elements in addressing design challenges, and the geographic scope in which each is applied. It should be noted that Category 2 policies would not place a direct compliance obligation on electric generators, and therefore might not affect real-time functioning of the wholesale electricity market. As a result, such policies would not preclude the possibility of emissions leakage due to a re-dispatch of the regional power system in response to a RGGI compliance cost adder.

A carbon procurement adder would be a greater challenge to implement in a restructured market, absent significant modification to typical procurement processes. It would present a significant challenge for use as a planning tool to evaluate the carbon intensity of spot market power purchases that are a mix of system power including both low-emitting and high-emitting units.

A carbon procurement emission rate mechanism would be tied to the bundled electricity commodity, rather than an unbundled emissions attribute, and therefore would directly impact power plant dispatch. However, this policy is not suited to addressing power purchases from the spot market.

An EPS would impose a market signal on LSEs that lower-emitting generation is a valuable commodity. However, for purposes of mitigating emissions leakage, an EPS would only indirectly impact the dispatch of generators in the region. Since an EPS imposes procurement requirements on

LSEs, this policy can be expected to affect generation dispatch to the degree that all LSEs in the market were required to comply with an EPS. Such an implementation scenario, however, would not be possible in the PJM control area, the control area of greatest concern with regard to potential emissions leakage.

For these and other reasons, Staff concludes that the development and implementation of a carbon procurement adder, a carbon procurement emissions rate, and an emissions portfolio standard can be expected to require significant development and implementation lead-time and full participation from both energy and environmental agencies. Staff also notes that the effectiveness of such policies in mitigating emissions leakage remains uncertain and would likely be context- and design-specific.

Staff also notes that the implementation of such policies could have significant ratepayer impacts, and that there might also be a partial "pancaking" of ratepayer impacts resulting from the parallel implementation of Category-2 policies alongside the RGGI cap-and-trade program. Staff notes that incremental CO_2 emissions reduction benefits might not be achieved at a level commensurate with such ratepayer impacts, due to the need to implement programs that do not differentiate among electric generation sources capped under RGGI, and representing the majority of generation serving load in the RGGI region, and electric generation sources not subject to RGGI and serving a minority of load in the RGGI region.

Category 3 – Capping Emissions Associated with Serving Load

The third policy category, referred to here as a "load-based emissions cap-and-trade program", or "load-based cap", would place a cap on absolute emissions related to all electricity delivered for sale to retail customers by an LSE.[66] Under this policy, a cap could be based on:

• A stabilization of historic emissions related to electricity use within the LSE service territory;

• The application of an emissions trajectory, beginning at a historic level of emissions related to electricity use within the LSE service territory; or

[66] As noted in the Initial Report, several load-based cap-and-trade policies have been proposed to the RGGI Staff Working Group. One, in May 2004, was proposed as an alternative to the RGGI cap-and-trade program. This has been referred to as an "allocation-to-load" proposal. See, R. Cowart, "Another Option for Power Sector Carbon Cap-and-Trade System – Allocation-to-Load," Regulatory Assistance Project, May 1, 2004. In the spring of 2006, a second, more narrowly-tailored, load-based proposal sought to augment the RGGI cap-and-trade program and focused only on imported power and associated emissions. Based upon discussions with experts, Staff concluded that for legal reasons the proposal was problematic. *See* Cowart, R., "Addressing Leakage in a Cap-and-Trade System: Treating Imports as Sources," Regulatory Assistance Project, April 2006. The discussion here reviews the load-based emissions cap concept as an emission leakage mitigation policy, *i.e.,* as adjunct to the existing RGGI cap-and-trade program. For further discussion of the "load-side cap" *see* Initial Report at 39-42.

• An emissions rate (cap is equal to an emissions rate multiplied by a projected number of MWhs delivered by the LSE; assumed MWhs delivered could be capped).

For this policy, an emissions cap for an LSE or group of LSEs would be set, most likely based on their historic electricity purchases and related emissions. Allowances would then be allocated to LSEs based on a specified mechanism, which could vary depending on program design. At the end of each compliance period, an LSE would have to submit allowances in a number equivalent to the carbon emissions associated with the generation supply that the LSE used to serve its load.

LSEs would be able to reduce the carbon content of their portfolios by contracting with the providers of relatively low-emitting generation and reducing load in their service territories through end-use energy efficiency and demand-side management. LSEs that reduced emissions below their allowance allocation would have allowances to sell; LSEs that failed to maintain emissions at the level of their allowance allocation would need to purchase allowances from other LSEs that have excess allowances to sell.

The load-based cap mechanism provides for all market-based approaches available to LSEs to comply with the policy. LSEs could purchase low-emitting power on the wholesale market, invest in end-use energy efficiency and other demand-side management resources, or purchase emissions allowances from other LSEs if it is more economic to do so. The ability to use emissions offsets could also be included in such a program, although Staff has not evaluated the policy case for including an offset provision.

Compliance with a load-based cap would be tracked in a similar fashion as an EPS, using a hybrid of ISO market settlement systems and generator attribute tracking systems. Specific emissions attributes would be applied to LSE transactions where a specific generation plant, and its related emissions, could be identified (plant-specific bilateral electricity purchases and renewable energy attribute credits, which are assumed to represent the addition of incremental renewable generation capacity). With the exception of those MWhs for which a plant-specific emissions attribute is allowed, all other MWhs delivered to meet LSE load would be assigned a "residual mix" emissions attribute. This LSE-specific residual mix emissions attribute would be the CO_2 emissions rate for all other generation units in the control area, after subtracting for the generation from those generation units for which LSEs in the regulated region are allowed to claim plant-specific emissions attributes.

Criterion 1 -- *Accomplishes the goal of adequately addressing emissions related to the end-use of electricity in the most flexible, cost-effective manner*

If properly designed, and depending on the market scope to which it is applied, a load-based cap could be effective in addressing potential emissions leakage. However, a load-based cap would be subject to similar implementation challenges as an emissions portfolio standard, namely the potential for attribute shuffling and contract shuffling, and would encounter similar program complexities in attempting to address such dynamics. In addition, a load-based cap would be subject to the same geographic scope issues as an EPS that could undermine the effectiveness of a load-based cap as an emissions leakage mitigation mechanism.

Additionally, it should be noted that since generators would face no direct compliance obligation under this policy, a load-based cap would only indirectly impact the real-time dispatch of generators in the region. Consequently, a load-based cap might not preclude emissions leakage resulting from a real-time re-dispatch of the regional power system due to a RGGI compliance cost adder.

In addition, a load-based cap would face complexities and challenges unique to the design of cap-and-trade programs, which could rival the level of effort expended in the design of the RGGI program. Establishing an LSE emissions cap would present a significant undertaking. This would require the establishment of emissions estimates related to historical electricity purchases by each LSE over a multi-year period. Unlike a process for estimating regional emissions leakage, establishing LSE baselines for a load-based cap-and-trade system could require detailed analysis of historic LSE bilateral power purchases and spot market purchases, and an estimate of the emissions related to those purchases. This would require the use of both generator attribute tracking systems and ISO market settlement systems to evaluate the contract path of LSE electricity purchases. As a result, it would present significant additional requirements beyond those that would be required to track regional emissions leakage through a generator attribute tracking system. In addition, a mechanism would need to be established for the allocation of allowances to LSEs, either through direct allocation or auction. The development of such a mechanism would also present a significant undertaking.

A significant challenge arises when considering the potential integration of the RGGI cap-and-trade program with a load-based cap. In the Initial Report Staff indicated that some proponents of the implementation of a load based cap in the RGGI region argued that such a policy should be implemented so as to allow for allowance trading between a load-based cap-and trade system and the generator-based, RGGI cap-and-trade system. This would allow generators and LSEs to trade their respective allowances with each other, making allowances in the load-based and generator-based systems fully fungible. Due to emissions tracking issues, Staff recommended that if a load-based cap were considered, it should not be implemented in coordination with the RGGI program, but instead should be operated in parallel with the existing program. Trading at, least initially, should not be considered between the two systems.[67]

As a result, the implementation of a load-based cap could have significant ratepayer impacts, and there might also be a partial “pancaking” of ratepayer impacts resulting from the parallel implementation of a load-based cap alongside

[67] Determining the level of emissions attributable to electricity use by LSEs is subject to a significant degree of imprecision and uncertainty compared to the monitoring and reporting of emissions under a generator-based cap-and-trade system. Given the significant differences in monitoring precision, it is unreasonable to assume the fungibility of allowances between the two programs.

the RGGI cap-and-trade program. Staff notes that incremental CO_2 emissions reduction benefits might not be achieved at a level commensurate with such ratepayer impacts, due to the need to implement programs that do not differentiate among electric generation sources capped under RGGI, and representing the majority of generation serving load in the RGGI region, and electric generation sources not subject to RGGI and serving a minority of load in the RGGI region.

Criterion 2 -- *Maintains and/or enhances system reliability*

As discussed for Category-1 and Category-2 policies, a load-based cap would have no significant effect upon electricity system reliability because this policy does not place a direct compliance obligation on electric generation units.[68] By placing a specific carbon emissions requirement on an LSE, a load-based cap could be expected to provide significant incentives to expand investments in electricity load reduction and demand-side management, thereby enhancing electricity system reliability.

Criterion 3 -- *Ensures that electric power generated within the RGGI region is treated similarly to electric power generated outside the region*

Like a carbon procurement adder, carbon procurement emissions rate, and emissions portfolio standard, a load-based cap does not distinguish between specific generation resources or their geographic location. In the Initial Report, Staff noted that states cannot purposely discriminate against interstate commerce through the differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter.

Because a load-based cap would affect the manner in which RGGI-region LSEs acquire electricity, as opposed to how electricity generators supply electricity to the wholesale market, this policy makes no distinction between electric power generated within the RGGI region and electric power generated outside the region. Staff therefore concludes that a load-based cap, to the extent that it addresses all electricity delivered for retail sale by an LSE, would ensure that power generated outside the region is not treated any differently than power generated within the RGGI region.

Criterion 4 -- *Remains relevant even after a mandatory federal greenhouse gas emissions reduction policy is in place*

If a mandatory federal greenhouse gas emissions reduction policy were to be implemented, a load-based cap as an adjunct to a generator-based cap-and-trade program would no longer be relevant. In its Initial Report, Staff noted that the implementation of a national carbon cap-and-trade program would in large part address the emissions leakage issue. This conclusion has not changed, because a federal program, by definition, would extend beyond RGGI's

[68] For more discussion, *see* Initial Report at 42-44.

current borders to include nearly all supply resources serving load in the RGGI region.[69]

Criterion 5 -- *Encourages energy efficiency and/or carbon efficiency in the generation and end-use of electricity*

Assuming that the challenges associated with attribute shuffling and contract shuffling were adequately addressed, the implementation of a load-based cap would be expected to encourage end-use energy efficiency and carbon efficiency in the generation of electricity, provided that the program covered all or most of an ISO control area.

Under this policy, because LSE portfolios managers would be subject to an emissions cap, they would be required to adjust their company supply portfolios on the basis of carbon content and would likely consider alternatives such as end-use energy efficiency and lower-emitting generation sources as they evaluate options for serving load. However, as the discussion regarding attribute shuffling and contract shuffling indicates, there are likely to be technical challenges associated with the tracking of attributes associated with LSE supply portfolios.

Criterion 6 -- *Compatibility with other energy and environmental policies that address the end-use of electricity*

The adoption of a load-based cap would complement polices addressing electricity end-use, as greater investment in end-use energy efficiency and demand-side management would present a highly economic compliance strategy under a load-based cap.

Criterion 7 -- *Policy development and implementation time frame*

The development of a load-based cap in the RGGI region would likely require legislative authorization in many states, followed by the development of an extensive regulatory framework. It would also require significant technical and policy development to implement.

The implementation issues associated with the development of a load-based cap would be similar in many ways to the development of the RGGI cap-and-trade program, but with additional design complexities resulting from the need to track emissions related to electricity use and the incorporation of design elements intended to minimize the potential for attribute shuffling and contract shuffling. At a minimum, it would be necessary to undertake a regulatory process to establish the following: 1) individual LSE emissions baselines (requiring the development of emissions estimates related to historical electricity purchases by each LSE over a multi-year period); 2) a mechanism for allocating allowances; 3) a system to account for emissions related to electricity use and

[69] "Nearly all" refers to all generation resources within the United States, not those located in Canada or Mexico that serve load in the U.S.

track emissions and allowances; and 4) development of a system to track power purchases.

Incorporation of design elements to minimize the potential for attribute shuffling and contract shuffling, in particular, could extend the timeframe for development of a load-based cap. Given the greater value of addressing potential leakage in the near- and mid-term, there remains the question of whether a load-based cap could be implemented in a useful timeframe.

Criterion 8 -- *Significant implementation and administrative considerations*

As the discussion above indicates, while a load-based cap has some positive design features, the implementation of such a mechanism would present numerous challenges.

First, there is the question of the geographic scope necessary to ensure that a load-based cap impacts the dispatch of the regional power system, which would be required to mitigate potential emissions leakage. In the PJM control area, the control area of primary concern with regard to emissions leakage potential, it appears that the scope of regulatory coverage might not be sufficient to ensure such an impact. This would create the potential for the system to be undermined by attribute shuffling or contract shuffling. Developing a system to limit the possibility of such outcomes would require the incorporation of significant design complexity and would also limit the compliance options available to LSEs.

As mentioned previously, the implementation of a load-based cap could have significant ratepayer impacts, and there might also be a partial "pancaking" of ratepayer impacts resulting from the parallel implementation of a load-based cap alongside the RGGI cap-and-trade program. Staff notes that incremental CO_2 emissions reduction benefits might not be achieved at a level commensurate with such ratepayer impacts, due to the need to implement programs that do not differentiate among electric generation sources capped under RGGI, and representing the majority of generation serving load in the RGGI region, and electric generation sources not subject to RGGI and serving a minority of load in the RGGI region.

Conclusions for the Category-3 Policy Option

Implementation of a load-based cap would present significant technical and administrative challenges that would likely lead to a lengthy development time frame. It is also unclear whether such a mechanism would present an effective leakage mitigation strategy, especially if the geographic scope to which it was applied did not include all or most of a respective ISO control area.

The effectiveness of a load-based cap in mitigating emissions leakage would likely be dependent on the geographic scope to which was applied and the success of specific design elements in addressing design challenges such as attribute shuffling and contract shuffling. It should also be noted that a load-based cap would not place a direct compliance obligation on electric generators, and therefore might not affect real-time functioning of the wholesale electricity market. As a result, a load-based cap would not preclude the possibility of emissions leakage due to a re-dispatch of the regional power system in response to a RGGI compliance cost adder, especially if such a program was only applied to part of an ISO control area.

The implementation of a load-based cap could also have significant ratepayer impacts, and there might also be a partial "pancaking" of ratepayer impacts resulting from the parallel implementation of a load-based cap alongside the RGGI cap-and-trade program. Staff notes that incremental CO_2 emissions reduction benefits might not be achieved at a level commensurate with such ratepayer impacts, due to the need to implement programs that do not differentiate among electric generation sources capped under RGGI, and representing the majority of generation serving load in the RGGI region, and electric generation sources not subject to RGGI and serving a minority of load in the RGGI region.

Due to these challenges and the uncertain effectiveness of such a mechanism in mitigating emissions leakage, Staff recommends that a load-based cap should not be prioritized for implementation at this time.

Conclusions and Recommendations on Policy Options to Mitigate Potential Emissions Leakage

In light of a political environment that strongly suggests emerging support for a national carbon cap-and-trade program, which could be expected to eliminate or mitigate the potential for emissions leakage, Staff recommends that:

1. The RGGI participating states should monitor for emissions leakage and further evaluate the potential extent of projected leakage in the context of recent state efforts to significantly expand investments in end-use energy efficiency programs. Further, the RGGI participating states should incorporate the evaluation criteria outlined above when evaluating the potential implementation of specific measures to mitigate leakage.

2. The RGGI participating states should prioritize the implementation of leakage mitigation measures with demonstrated effectiveness and short implementation time frames. Specifically, RGGI participating states should pursue a leakage mitigation approach of aggressive increases in investment in energy efficiency market transformation programs, and the implementation and expansion of complementary policies such as building energy codes and appliance and equipment efficiency standards that accelerate the deployment of end-use energy efficiency technologies and measures;

3. Because of their administrative complexities and challenges, as well as untested effectiveness as leakage mitigation strategies, Staff recommends that the policy options identified in Categories 2 and 3 – *i.e.*, a carbon procurement adder, carbon procurement emissions rate, emissions portfolio standard, and load-based cap – should not be prioritized for

implementation at this time, absent compelling evidence based on leakage monitoring that emissions leakage has become a significant issue.

4. The RGGI participating states should support the State of New Jersey's investigation into potential Category 2 and 3 leakage mitigation options, as any measures enacted as a result of this proceeding could facilitate broader regional implementation of such measures in the RGGI region if end-use energy efficiency measures prove insufficient as a leakage mitigation approach, or action toward the implementation of a federal cap-and-trade program is significantly delayed.

Stakeholders that Provided Comments on March 2007 Initial Emissions Leakage Report

AES Corporation
APX
Associated Industries of Massachusetts
Connectiv Energy
Conservation Law Foundation
Dominion
Edison Electric Institute
Environment Northeast
Gabel Associates
Independent Power Producers of New York
International Brotherhood of Electrical Workers, Locals 83 & 97
New Jersey Department of the Public Advocate, Division of Rate Council
New York Independent System Operator
Northeast Regional Greenhouse Gas Coalition
Northeast Suppliers
Northeast Utilities System
PSEG Services Corp.
Union of Concerned Scientists
Unions for Jobs and Environment
World Resources Institute

The Availability of Carbon Emissions Abatement and Sequestration Technologies[70]

Introduction

The cap-and-trade program established under Title IV of the 1990 Clean Air Act, as well as the NO_X Budget Program, have achieved significant reductions in emissions of sulfur dioxide and oxides of nitrogen.[71] Under these programs, commercialized emissions abatement technologies were available for both pollutants. This is not the case for CO_2. As explained below, current technological assessments of available carbon emissions abatement and carbon sequestration technologies emphasize the need for a near- and mid-term focus on end-use efficiency and the development of cleaner, lower emitting generation. Given the current lack of commercialized control technologies for CO_2, end-use energy efficiency – along with the deployment of renewable generation resources – will be the main tools for the electricity sector to rely on in addressing carbon emissions in the near- and mid-term.[72]

The Status of Various Technologies

Although it is difficult to determine the timeframe for commercializing carbon emissions abatement and carbon capture and storage technologies, a number of presentations given by industry experts at the 2007, Summer Conference of the National Association of Regulatory Utility Commissions ("NARUC") and other similar policy statements suggest three things. One, CO_2 abatement and capture technology is still at the research, development, and demonstration stage (RD&D). Two, the current emissions reduction options available on the supply-side continue to be the utilization of low- or non-emitting generation. Three, on the demand-side, there are significant opportunities to avoid CO_2 emissions through investment in end-use energy efficiency resources.

At the NARUC Summer meetings, the Electric Power Research Institute's ("EPRI") Steven Specker argued that it is "technically feasible to slow, stop, and eventually reduce the increase of CO_2 emissions from the U.S. electric sector," but that achieving this goal would require a commitment to aggressive public and private sector research and development, and an accelerated commercial deployment of advanced technologies.[73]

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[70] A summary of selected presentations at the 2007 Summer Conference of the National Association of Regulatory Utility Commissions (NARUC), New York City.
[71] *See* U.S. EPA, "Cap-and-Trade: Acid Rain Program Results" (available at: http://www.epa.gov/airmarkt/cap-trade/docs/ctresults.pdf).
[72] It should be recognized that additional significant emissions reduction options are available to carbon-emitting generation facilities through environmental dispatch, improvements in facility heat rates, and fuel switching.
[73] Steven Specker, EPRI, NARUC 2007 Summer Conference.

Howard Herzog of MIT told NARUC Summer meeting attendees that "carbon capture and storage (CCS) is the critical enabling technology that would reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."[74] However, Herzog maintains that such technology is nowhere near market. Accordingly, Mr. Herzog argues that there is a need to drastically increase R&D to commercialize CO_2 capture technologies, with large-scale demonstration projects key to such progress.[75]

In recognizing the current technical and market uncertainty surrounding CO_2 abatement and capture technology, other industry leaders, as well as environmental advocates, have emphasized the importance of policies that encourage the deployment of low- and non-emitting generation technologies and the expansion of demand-side strategies as a way of bridging the gap until carbon emissions abatement and capture technology comes to market.[76] According to EPRI's Victor Niemeyer, "the largest emission reductions to result from imposing CO_2 costs will come over time by providing investment incentives for new generation that produces lower or no emissions."[77]

Likewise, implicit in remarks made by Secretary of Energy Bodman to the NARUC membership was the recognition that it will not be existing generation that is going to make the necessary CO_2 reductions:

> *There is no doubt that new energy sources must be developed. But there is also a clear and growing recognition of the role that prioritizing energy efficiency must play. As most of you know, the largest source of immediately available "new" energy is the energy we waste every day. Indeed, it is the cheapest, most abundant, cleanest, most readily available*

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[74] Howard Herzog, "The Role of Coal Generation in a World of Greenhouse Gas Regulation," NARUC 2007 Summer Conference.

[75] *Id*. Herzog also indicated that it is so early in this process that it would be "premature" to select one coal conversion technology as the preferred route for cost-effective electricity generation combined with CCS, due to variability in location, coal type, and uncertainty in technological progress. Furthermore, with regard to retrofitting plants lacking CCS capability, he reported:

> Other than a few low-cost measures such as providing for extra space on the plant site and considering the potential for geologic CO_2 storage in site selection, the opportunity to reduce the uncertain eventual cost of CCS retrofit by making preparatory investment in plants without CO_2 capture does not look promising.

Id.

[76] A cap-and-trade mechanism was described by several RGGI stakeholders as a "bridge to a lower carbon" intensive economy. *See, Developing a Framework for Offset Use in RGGI*, Dale Bryk, National Resource Defense Council, and Brian Jones, Michael J. Bradley & Associates presentation to RGGI Stakeholders Workshop on Offsets, June 25, 2004.

[77] Victor Niemeyer, Manager, EPRI Global Climate Risk Management, "The Change in Profit Climate," Public Utilities Fortnightly, May 2007, at 26.

> *source of energy Americans can access, and your work --- your leadership --- is the key to unlocking its widespread use.*[78]

Similarly, the U.S. Climate Action Partnership (USCAP), a group of major corporations and national environmental organizations, recently provided recommendations to Congress on how to address the challenge of climate change.[79] In its first recommendation, entitled, "Recognize the Importance of Technology," USCAP emphasizes both the supply-side and demand-side CO_2 reduction opportunities that are available today:

> *There are a number of technologies that are currently available that emit little or no [greenhouse gases], such as wind, solar, and nuclear power, hybrid vehicles, and numerous energy efficiency technologies. The cost-effective deployment of existing technologies to improve energy efficiency and reduce GHG emissions should be a priority, as it will yield emission reductions in the near-term while new technologies are developed.*[80]

In conclusion, due to the lack of commercialized carbon emissions abatement and carbon capture and storage technology, it is reasonable to conclude that end-use energy efficiency policies, the deployment of low- or non-emitting generation, and energy efficiency improvements and fuel switching for existing generation will continue to be the primary tools for the electricity sector to rely on in controlling carbon emissions in the near future.

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[78] Prepared Remarks for Secretary of Energy Bodman presented at National Association of Regulatory Utility Commissioners (NARUC) Summer Meeting July 16, 2007.

[79] U.S. Climate Action Partnership, "Call for Action". The U.S. Climate Action Partnership Members include: Alcan Inc., Alcoa, American International Group, Inc., Boston Scientific Corporation, BP America Inc., Caterpillar Inc., Chrysler LLC., ConocoPhillips, Deere & Company, Dow Chemical Company, Duke Energy, DuPont, Environmental Defense, Exelon Corporation, Ford Motor Company, FPL Group, Inc., General Electric, General Motors Corp., Johnson & Johnson, Marsh, Inc., National Wildlife Federation, Natural Resources Defense Council, The Nature Conservancy, NRG Energy, Inc., PepsiCo, Pew Center on Global Climate Change, PG&E Corporation, PNM Resources, Rio Tinto, Shell, Siemens Corporation, World Resources Institute, and Xerox Corporation.

[80] *Id*. at 5. *See also* "Environmental Issues in System Planning," Presentation by Jim Platts, ISO New England, NARUC Summer Meeting, July 15, 2007,

Summary of State Implementation of Category-1 End-Use Energy Efficiency Policies and Programs

Energy Efficiency Portfolio Standards

An energy efficiency portfolio standard (EEPS or "efficiency standard") is a market-based mechanism that mandates improvements in end-use energy efficiency by requiring utilities to meet targets for electric (and/or natural gas) energy savings. Of the RGGI participating states, Vermont, Connecticut, and New York have adopted or are in the process of adopting an EEPS or similar standard.[81]

Connecticut recently expanded its renewable portfolio standard to include energy efficiency. Connecticut's investor-owned utilities are now required to procure a minimum percent of their electricity supply from "Class III" resources (*i.e.*, energy efficiency). The standard requires a ramping-up of the percentage of each utility's load to be met through energy efficiency resources as follows: one percent in 2007, two percent in 2008, three percent in 2009, and four percent in 2010.[82]

In 1999, the Vermont Public Service Board transferred the efficiency programs in 21 of the state's 22 utilities to Efficiency Vermont ("EVT").[83] EVT is an independent contractor tasked with managing the states electric energy efficiency programs. Pursuant to its contract, EVT is required to achieve specific energy and demand goals for the overall public benefits program.

Combined Heat and Power (CHP) Technologies

Combined heat and power or "cogeneration" systems produce both power and thermal energy at the same time from a single fuel source. Unlike central station power plants that typically operate at between 30 to 35 percent efficiency, CHP uses heat recovery technologies that capture heat that would otherwise be wasted and use it for other purposes, including space heating, cooling, and powering industrial equipment.[84] The use of waste heat can increase thermal efficiency significantly, by up to 85 percent.[85] While many CHP systems burn gas or other fossil fuels, such systems generally also displace fuel previously used on-site for heat, and they displace generation by fossil fuel-fired power

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[81] Dan York and Martin Kushler *A Nationwide Assessment of Utility Sector Energy Efficiency Spending, Savings, and Integration with Utility System Resource Acquisition*, American Council for an Energy-Efficient Economy (ACEEE), 2006.
ACEEE, 2006 at 10.
[82] *Id*. at 12.
[83] The Board authorized one electric utility, the City of Burlington Electric Department to continue delivering in its service territory most of the programs offered by Efficiency Vermont.
[84] ACEEE 2006 at 13-20.
[85] *Id*. at 13-14.

plants. The result is a significant net reduction in fuel usage and carbon emissions in the region, due to the improved overall efficiency of providing energy services. As a result of the reduced demand for central-station generation, widespread deployment of CHP systems has the potential to significantly reduce the wholesale market-clearing price of electricity.

There are a number of barriers to the development of CHP. These include high standby electricity rates and lengthy interconnection agreements. Some states have developed policies that seek to remove barriers to the deployment of CHP, including standard interconnection rules for distributed generation that include CHP.[86] States have also developed financial incentives programs (*e.g.*, grants, low-interest loans, and rebates), and included CHP as an eligible technology in state renewable portfolio standards and energy efficiency portfolio standards (Table 1).

Table 1. State Policies and Programs Supporting CHP Deployment

State[87]	Standard Interconnection Rule that includes CHP[88]	Output-based Emissions Regulation	State CHP Financial Incentives	CHP Included in State RPS or EEPS
NJ	X [89]	X	X	
NY	X	X	X	
CT	X	X	X	X
MA	X	X		
DE	X	X		
VT	X		X	
MD	X	X		
ME		X		X
RI				
NH		X	X	

Several RGGI participating states have developed policies that encourage the development of CHP. New York adopted uniform interconnection standards for distributed generation systems in 1999, and has streamlined and expanded their applicability.[90] The Massachusetts Department of Telecommunications and Energy (DTE) developed an interconnection rule for distributed generation in 2002.[91] In 2005, the DTE approved a Revised Model Distributed Generation Interconnection Standards and Procedures Tariff.[92]

[86] *Id*.
[87] Table adapted from *ACEEE, 2006* at 19.
[88] *See also*, *Survey of Interconnection Rules, Prepared for the Florida Public Service Commission*, Wayne Shirley, Regulatory Assistance Project, August 27, 2007.
[89] ACEEE characterizes as “exemplary” the standardized interconnection rules implemented by the states of New Jersey, New York, Connecticut, and Massachusetts. ACEEE at 16, 19.
[90] The New York Public Service Commission streamlined its application process in 2002, and increased the maximum capacity of interconnected systems from 300kW to 2 MW. New York has also expanded interconnection to urban distribution systems. *Id*. at 16.
[91] *Id*. at 20.
[92] *Id*.

Some RGGI participating states have also adopted renewable portfolio standards (RPS) and energy efficiency portfolio standards that require electricity providers to fill a minimum amount of their generation resource needs from eligible clean energy and energy efficiency technologies. Maine and Connecticut include CHP in their renewable portfolio standards.[93]

Certain RGGI participating states have also developed other incentives for CHP projects. NYSERDA has adopted a program that provides support for demonstration projects of innovative applications of clean generation, including CHP.[94] The New Jersey Clean Energy Program administered by the New Jersey Board of Public Utilities also provides incentives for the installation of CHP resources.

Connecticut has developed output-based emissions regulations for small distributed generation that values CHP efficiency based on avoided emissions. In 2003, New York developed electricity standby and backup rates to remove market barriers to CHP deployment.[95] Reasonable standby electricity rates have been found to be crucial in ensuring the cost effectiveness of CHP projects. In March 2008, Massachusetts proposed regulations to recognize and credit the emissions benefits of CHP projects during the permitting process.

Building Energy Codes

According to the American Council for an Energy-Efficient Economy (ACEEE), building energy use accounts for 40 percent of total energy use and greenhouse gas emissions in the U.S., and 65 percent of total U.S. electricity use.[96] New building energy efficiency standards are important due to the long life-span of building stock and the fact that building retrofits are typically more expensive and less effective in reducing energy use than incorporating energy efficiency measures during initial building construction. Building codes are one way of ensuring that residential and commercial buildings incorporate energy efficiency measures during initial construction and as part of major building retrofits.

The most common building energy code standard for residential buildings is the International Energy Conservation Code ("IECC"). The most common commercial building energy code standards for commercial buildings are the

[93] *Id.* at 21. To receive credits under as a Class III resource under Connecticut's portfolio standard, CHP systems must be new, i.e., built after January 1, 2006, and must achieve certain efficiency levels. Existing units that have been modified after January 1, 2007 can also receive credits for their incremental output gains. *Id*.
[94] *Id*. at 22; *see also* http://chp.nyserda.org
[95] *Id*.; These refer to utility rates that a customer pays to receive power from the grid at times when its own distributed generation is unavailable, either unexpectedly or for maintenance reasons.
[96] ACEEE 2006 at 24-29.

IECC and the code adopted by the American Society for Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE).[97]

Each RGGI participating state has adopted building energy codes for commercial construction, and nine out of ten have adopted building energy codes for residential construction (Table 2). New Jersey has adopted the most recent version of the IECC which was published in 2006. Rhode Island, Maryland, and Connecticut have adopted the IECC 2003-2006 or equivalent for residential construction, and the IECC 2003-2006 or ASHRAE 90.1-2001/2004 or equivalent for commercial construction.

Delaware, New Hampshire, New York, and Vermont have adopted the 1998-2001 IECC and portions of the 2003 IECC code for residential construction, and the 1998-2001 IECC or ASHRAE 90.1-1999 and portions of the 2003 IECC code for commercial construction.[98]

The State of Maine, for purposes of residential construction, has developed a code called the Maine Model Building Energy Code, which is based on the 2003 IECC. Depending on the status of currently-adopted codes at the local level, Maine towns may adopt this standard or retain their existing codes. For purposes of commercial construction, Maine has adopted the 2003 IECC or ASHRAE 90.1-2001 standard and applies it statewide.[99] Massachusetts has also adopted its own code for residential construction. For commercial construction, Massachusetts' state code is based on the ASHRAE 90.1-1999, and 2001 IECC. It also contains other state-developed amendments.[100]

Table 2. State Building Energy Codes

State	Residential	Commercial
Maine	IECC-2003/ASHRAE-2001	IECC-2003/ASHRAE-2001
New Hampshire	IECC-2006	IECC-2006
Vermont	Precedes IECC-1998	IECC-1998-01/ASHRAE-2001
New York	IECC-2004	IECC-2003/ASHRAE-2001
Massachusetts	IECC-2001/ASHRAE-1999	IECC-2001/ASHRAE-1999
Connecticut	IECC-2003	IECC-2003
Rhode Island	IECC-2006	IECC-2006
New Jersey	IECC-2006	ASHRAE-2004
Delaware	IECC-2000	ASHRAE-1999
Maryland	IECC-2006	IECC-2006

[97] *Id*. at 25.
[98] *Id*. at 29.
[99] *Id*.; see also North Carolina Solar Center and Interstate Renewable Energy Council, DSIRE Database of State Incentives for Renewables and Efficiency (available at: http://www.dsireusa.org).
[100] *Id*. at 27.

Appendix and Equipment Energy Efficiency Standards

Appliance and equipment energy efficiency standards establish minimum energy efficiency levels for classes of commercial and residential appliances or equipment. Efficiency standards ensure that as existing equipment stock is slowly turned over, new equipment meets minimum efficiency standards. Efficiency standards serve to lock efficiency gains into the marketplace and provide an efficiency “floor” for market transformation programs.

As noted in the Initial Report, numerous states are implementing appliance and equipment energy efficiency standards, where cost effective, for products that are not already covered by federal mandates.[101] According to a study by ACEEE and the Appliance Standards Awareness Project (ASAP), the adoption of appliance and equipment energy efficiency standards in the RGGI region could result in energy savings of approximately 8,600 GWh by 2020 which is equivalent to a 1.8% reduction in regional electricity use.[102]

[101] The Energy Policy Act of 2005 (EPAct 2005) preempts states from setting their own standards for the products covered by federal standards. States that had set standards prior to federal enactment may enforce their state standards until federal standards become effective.

[102] Initial Report at notes 42-43 and accompanying text. Nadel et al., “Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards,” ACEEE Report Number A051 and ASAP Report Number 5, 2005 (available at: http://standardsasap.org/stateops.htm). The percentage load reduction estimate was calculated based on forecasted demand growth data used in RGGI IPM modeling analysis.

State Renewable Portfolio Standards

A renewable portfolio standard (RPS) is a policy that obligates a load-serving entity (LSE) to include in its portfolio of generation supply resources used to supply customers a certain amount of electricity from renewable energy resources, such as wind and solar energy. LSEs satisfy the obligation by either (a) owning a renewable energy facility whose power the LSE uses, or (b) purchasing renewable energy credits (RECs) from another facility.[103]

Table 1. A Summary of State Renewable Portfolio Standards[104]

This table provides a summary of renewable portfolio standards adopted by states and the District of Columbia, and links to administering organizations. RGGI states are highlighted.[105]

State	Amount	Year	Organization Administering RPS
Arizona	15%	2025	Arizona Corporation Commission
California	20%	2010	California Energy Commission
Colorado	20%	2020	Colorado Public Utilities Commission
Connecticut	23%	2020	Department of Public Utility Control
District of Columbia	11%	2022	DC Public Service Commission
Delaware	20%	2019	Delaware Energy Office
Hawaii	20%	2020	Hawaii Strategic Industries Division
Iowa	105 MW		Iowa Utilities Board
Illinois	25%	2025	Illinois Department of Commerce
Massachusetts	4%	2009	Massachusetts Division of Energy Resources
Maryland	9.5%	2022	Maryland Public Service Commission
Maine	10%	2017	Maine Public Utilities Commission
Minnesota	25%	2025	Minnesota Department of Commerce
Missouri*[106]	11%	2020	Missouri Public Service Commission
Montana	15%	2015	Montana Public Service Commission
New Hampshire	16%	2025	New Hampshire Office of Energy and Planning
New Jersey	22.5%	2021	New Jersey Board of Public Utilities
New Mexico	20%	2020	New Mexico Public Regulation Commission
Nevada	20%	2015	Public Utilities Commission of Nevada
New York	24%	2013	New York Public Service Commission
North Carolina	12.5%	2021	North Carolina Utilities Commission
Oregon	25%	2025	Oregon Energy Office
Pennsylvania	18%	2020	Pennsylvania Public Utility Commission
Rhode Island	15%	2020	Rhode Island Public Utilities Commission
Texas	5,880 MW	2015	Public Utility Commission of Texas
Vermont*	10%	2013	Vermont Department of Public Service
Virginia*	12%	2022	Virginia Department of Mines, Minerals, and Energy
Washington	15%	2020	Washington Secretary of State
Wisconsin	10%	2015	Public Service Commission of Wisconsin

[103] RECs generally represent the environmental and other attributes associated with energy production.
[104] Source: U.S. Department of Energy.
[105] Percentages refer to a portion of electricity sales, and megawatts (MW) to absolute capacity requirements. The majority of these standards phase in over a period of years. Dates denote the year in which the full requirement takes effect.
[106] The asterisk (*) indicates states that have set goals for meeting renewable energy targets instead of imposing portfolio standards with binding requirements.