15 August 2006

Mr. Franz Litz
Senior Attorney & RGGI Coordinator
NYS Department of Environmental Conservation
625 Broadway, 14th Floor
Albany, NY 12233-1500

Dear Mr. Litz:

RE: CO_2 Allowance Issues: Observations and Recommendations

I am writing to follow-up on my presentation at the recent RFF Auctions Workshop, and offer additional thoughts on the consideration of how allowances are allocated in the RGGI program.

On the assumption that the allocation of CO_2 allowances under RGGI will be a mix of historical allocation and auctioned allowances, I believe that operating requirements imposed by the needs of the electric power system should limit the public benefit auction to no more than 25% of the total allowances. A prudent approach to the development of the auction involves an understanding of the impact on the electric system of the proposed cap and trade policy with an initial auction of the allowances. I want to clarify how the allocation will affect certain aspects of the power system, ranging from long run investments in capacity to very short run reliability requirements. My perspective is two-fold:

1. Support for a market-based approach such as the cap and trade system, tempered by a concern for the clarity of market signals in the long, medium, and short runs, and
2. Concern that the initial auction of allowances must be designed to allow liquidity to emerge in the trading environment.

Building on my presentation at the workshop, I want to consider the impact of the auction, cap, and trade system on:

1. Investment in new capacity.
2. Power purchase agreements.
3. The sale and procurement of installed capacity (ICAP).
4. The generation of power from capacity.
5. System and local reliability requirements.

Allocation Decisions and New Investment

Concerns

No clarity has emerged in the RGGI process as to how new investment will obtain allowances. There is a vague reliance on the secondary trading environment that needs to be made more explicit by articulating the rules for participation in the public benefit auction. Even if and when the secondary market becomes liquid, if allowances are fungible only in a three-year window (absent a triggering event), longer-run investment decisions will face very large and potentially unmanageable uncertainties. Most stakeholders would agree that market and other signals stemming from allowance allocation decisions should support new investment as appropriate.

Studies by the NYISO and ConEd have both indicated that a combination of new generation and transmission will be needed within a short number of years. Units in the investment queue need explicit guidance very soon about how to obtain allowances. Units further back in the queue face even more uncertainty in the receipt of allowances since the numbers of allowances are expected to fall, by policy. Some of these units are not due into commercial service until at least the second three-year allocation cycle, but they need to have some idea of whether they will be able to obtain allowances, and in what price range the allowances might fall.

A large new source will take up a larger percentage of allowances in a state budget than in other cap and trade programs. This difference could have significant and unanticipated consequences on the market. For example, modeling conducted in support of the RGGI program included new power plants that had been approved through the Article X process in New York State. The base case modeling did not include any new coal units within the RGGI region, although a sensitivity analysis was conducted to allow for new coal units on an economic basis. Additions beyond those accounted for in Article X, for example , the recent Advanced Clean Coal Power Initiative announcement by Governor Pataki in New York, represent a significant increase in carbon emissions unaccounted for in the RGGI emissions cap even as they contribute to overall CO_2 efficiency of the fleet.

In order to assure full allocations for new units out of the set-aside account from the current allowance level, or future reduced allowance levels, a significant fraction of the 25% set-aside would have to be used. Otherwise the new units will be required to participate immediately in the uncertain markets, possibly putting existing units in the position of being unable to meet obligations of purchased power agreements (PPAs). There is more to say about PPAs, but it is important to understand that new investment decisions will require PPAs both for validation and financing.

For reasons described below, PPAs may become less attractive if allowances become scarcer and less flexible. Allocating allowances from the current cap to new investment puts existing PPAs at risk, and also creates uncertainty for future investment that will likely rely on PPAs, since the future agreements could become subject to the same risks as current agreements.

As CO_2 allowances become more uncertain in their availability, there is also a risk of undermining the ICAP spot auctions pursuant to the ICAP demand curve. The demand curve was incorporated into the ICAP process to provide a market signal for future investment in capacity whereby a certain amount of capacity above the minimum is purchased on behalf of load-serving-entities.

There is a risk that either current units or future investments will be unable to obtain the allowances necessary to run. If investors rethink their positions, the system could become short of capacity and reliability could be jeopardized. Not quite so extreme, but more likely, is the risk that new capacity costs will rise due to increased uncertainty in obtaining allowances and due to decreased availability of PPAs of any length.

Recommendations

A reasonable approach to facilitating desirable investment is to allocate allowances outside of the RGGI program in a “safe harbor” mode to new investments in emitters that are cleaner than the current fleet of similar emitters. That “safe harbor” allocation would be for a defined period, such as one or two compliance cycles. The cleaner new investment will be more economical in the market, and will put pressure on the older less efficient stock. If the secondary market is functioning well, allowances from the older stock will become available as its capacity factor falls in response to market forces. Thus, with time, the newer investment will not need the ”safe harbor” as it obtains allowances in the secondary market.

The Bulk Power Market and Power Purchase Agreements

Concerns

The ability to enter into bilateral contracts or PPAs – of any length – benefits generators and load-serving-entities. Loads can hedge much of the fluctuation of daily prices, while generators may be able to hedge swings in fuel prices. PPAs are also attractive and probably necessary to support new investment, since the PPAs represent a defined revenue stream against which to assess an investment’s viability.

Even a 75% historical allocation may create a risk for generators and other parties to PPAs. If allowances above the historical allocation must still be obtained to cover an owner’s existing PPAs, the owner may no longer be viable financially in the PPA. Moreover, an auction of too great a percentage, combined with a compliance window of three years will limit the length of future PPAs effectively to three years or less, while unduly increasing the financial risk of existing long-term PPAs.

Decreases in the length of future PPAs will increase the risk of future investment. Assessment of the financial viability of an investment depends on a forecast of a future revenue stream that is roughly coincident with the lifetime of the investment. At a minimum, a financial institution would expect a 10-20 year stream of revenues to have confidence that a planned investment is viable. PPAs of three years' duration are insufficient to support new investment decisions. Those investment proposals that are not rejected outright due to the increased revenue uncertainty will experience a deep discounting of future revenues, with financial consequences for the ICAP and the energy markets.

As noted above, the increased costs may possibly push generators to the point of losses associated with the PPAs. While some may characterize the possibility of losses as a business risk, it would have been unreasonable at the time the existing PPAs were executed to expect that the parties would propose (accept) a CO_2 cost that was unknown in magnitude, form, and likelihood. It would have been just as unreasonable for the parties to assume that the allocation method and size would deviate so significantly from previous emission allowance allocation methods and volumes. Previous auctions of emissions rights have been quite modest. For example, it was noted at the auction workshop that the Virginia NOx auction was initially 5% of the total (Virginia) allowances and 2% thereafter. The Irish auction of allowances was a little less than 1% of the (Irish) total. The EPA auction of SOx allowances was 2.8% of the total.

Uncertainty as to the viability of future PPAs, possibly extending across compliance periods, is likely to reduce their volume. With suppliers and demanders both being more active in the spot markets for power, price volatility may increase, and of course, all participants will have to seek new hedging strategies to keep risk levels within acceptable limits.

Recommendations

The existence of PPAs is an important reason to limit the public benefit set-aside to no more than 25%. The 75% historical allocation share should protect most owners who are parties to PPAs. A further level of protection can come from giving generators the right of first access to the auctioned allowances at a market price. Decision-makers will also need to commit to specific amounts of allowances to be made available in the auction cycles, the frequency of those cycles, and their timing. In doing so, they must consider the costs and benefits of a range of time horizons and auction sizes. Given the uncertainties associated with an auction of the proposed magnitude, caution would dictate a modest initial effort with continual re-evaluation of the results. The first public benefit auction might well encompass the six months of the first summer capability period under the RGGI regime. An auction of the subsequent winter capability period would follow after an assessment of the outcomes of the first auction. This consideration, along with definitive statements as to how new investments will obtain allowances, will help to provide clarity in the market.

Allowance Availability and the Installed Capacity Market

Concerns

Installed Capacity (ICAP) sales by owners carry the obligation to offer the energy from that ICAP into the Day-Ahead market (DAM). Uncertainty as to the liquidity of the secondary allowance market will increase the risk early on of selling ICAP, offering into the Day-Ahead market, and producing energy without sufficient allowances in hand. The spot markets for power become uncertain as well if allowances are unavailable from secondary or trading sources and if generators have little or no confidence in periodic true-up mechanisms.

That uncertainty will manifest itself in high prices paid for CO_2 allowances and consequently higher prices for power and possibly for installed capacity (ICAP). ICAP prices may well rise if enough existing generators or new investments opt out because of inability to obtain allowances or because of the implications of allowance costs.

It should be noted that market power mitigation rules in NYC actually prevent a large number of units in NYC from even being able to drop out. For these generators, the uncertainty in obtaining sufficient allowances will manifest itself in higher power prices.

Recommendations

Uncertainty in having enough allowances to cover ICAP sales can be minimized by subjecting no more than 25% of the allowances to the public benefit auction. Historical allocation of the remaining 75% would provide a modicum of market certainty to sustain the ICAP markets, facilitate the viability of the secondary market, and provide deliverability of energy. Limiting the auction to 25% would be a prudent step in protecting the availability of the installed reserve margin while letting some excess capacity be fully subject to market forces.

Moreover, RGGI can support the ICAP auction cycle by timing the initial historical allocations and auctions so that they occur prior to the relevant ICAP cycle. Specifically, the 75% historical allocation should take place as far in advance as possible to facilitate a transparent, liquid forward energy market that promotes energy trading over long durations. In the previous section, I described a feasible auction cycle that paralleled the capability periods on which the ICAP cycle is built. There is no reason that the public benefit auctions could not take place a year in advance of their respective capability periods. Generators can then enter the ICAP market with their desired levels of both historical allocation and auctioned allowances.

While units sometimes take a short fuel position when they offer generation into the market, they know that the settlement process allows them to purchase fuel in real-time (to produce electricity) or to purchase electricity directly from the market to meet their DAM commitment, whichever is cheaper. A robust and liquid CO_2 market is analogous to the NYISO's real-time balancing market. A reason to ensure that a robust and liquid CO_2 market is in place, is to reduce the risk that selling ICAP and incurring a DAM obligation will carry the distinct possibility of being short of allowances. The secondary market would facilitate the balancing of CO_2 obligations. There are also capacity auctions and adjustments that happen throughout the capability period, and again, CO_2 liquidity will be necessary for the monthly capacity transactions.

While a true-up process provides flexibility in meeting obligations, generators will enter the ICAP markets only to the extent that they have CO_2 allowances to support their supply of capacity, or if they have confidence that they can purchase allowances in an active and competitive secondary market. The CO_2 allocation process will need to be designed in a way that makes it robust and liquid so that there is the ability to buy and sell allowances in a secondary market to meet compliance obligations.

Power Generation

Concerns

If the secondary market has become viable, then there will be some willingness to produce power without a full allocation of allowances in hand. It should be recognized that the offer price for the power will appropriately incorporate the various costs associated with obtaining and using allowances. A generator that produces despite being short of allowances is betting that it will be able to obtain allowances at some price during the true-up period. Moreover, it is also betting that the price of the allowance will be less than the difference between its marginal cost and the LBMP that the generator receives for generating power and being a sub-marginal unit. Allowance costs include the following categories, not all of which are in play at any one time:

1. The allowance cost itself if the generator obtains the allowance before actually generating or shortly thereafter.
2. A risk-adjusted expected allowance cost if the generator does not or cannot immediately obtain the allowance, but expects to be able to obtain it within the true-up period. The risk-adjustment here reflects the possibility that the allowance might cost more than the profit the generator earned by generating power, as noted above.
3. The cost of being unable to obtain enough allowances during the true-up period and thus losing future allowances as the result of penalties.
4. The opportunity cost associated with using the allowance rather than banking it or selling it.

Recommendations

Compliance rules should be clarified, and decisions made as soon as possible about how many allowances will be made available in the initial and subsequent auction cycles. I noted earlier that decision-makers and stakeholders should weigh costs and benefits of a range of auction frequencies and sizes. Large amounts will put pressure on PPA owners and other generators to obtain the allowances early, increasing their financial burden. In addition to the direct costs of obtaining allowances in the auction, there are financing costs associated with holding large blocks of allowances for substantial periods of time. The secondary market, generators, and other stakeholders will benefit from clarity in the rules. Such clarity will help the secondary market to emerge and will reduce the pressure on generators to obtain large blocks of allowances for future compliance.

I have also recommended earlier that generators be given the right of first access at the market price. Alternatively, if all of the allowances in the three-year compliance period are made available at once, there need to be measures in place to ensure that the allowances do not all end up being owned by too few non-generating participants.

The Allocation Mix and System Reliability

<u>Concerns</u>

There will be reliability impacts if the allocation / auction design conflicts with how the electric power markets operate. The electric market, even though workably competitive, is not straightforward. My concern is that an allocation scheme that puts more than 25% of allowances into the auction will impinge on the rules for serving load reliably, and also increase the costs of doing so.

One dimension of reliability is the requirement to commit 1800 MW of various kinds of operating reserves and some number of MW to respond to instantaneous changes in load. An added layer of complexity is that there are local reliability rules that apply in various areas of NY, particularly in NYC and on Long Island. Some of these local rules require certain units to be running regardless of their economics, in order to meet certain anticipated situations. Other rules require that units be able to come on-line within 10 minutes to meet an unanticipated situation not covered by the 1800 MW of system reserves. Still other rules require that higher sulfur fuels be burned under certain circumstances.

What these requirements imply is that allowances must be available not only to those units that will supply power economically, but also to those units that may be uneconomic but that are necessary to provide operating reserves, regulation, and quickly-available power. It remains to be seen if the total of the allowances is sufficient to support the operations associated with providing economic power as well as meeting reliability requirements.

The reliability requirements also imply that the models on which the allowance determinations are based, may well understate the amount of CO_2 emitted by certain units. The reliability requirements impose a CO_2 burden on the system that may not have been captured in RFF's comparative analysis or in the earlier allowance modelling process. Those analyses have assumed full dispatchability of the system's flexible units. However, it is quite common for units to be committed only to support the various reliability requirements. In those circumstances, the units run at minimum generation levels and are typically less efficient and emit at higher rates than if they were running optimally. The units also do not set the market clearing prices in those circumstances and therefore cannot expect to recover their higher costs in higher clearing prices.

Another complication crosses the boundary between reliability requirements and the market itself. The NYISO's energy models are economic only within a 24-hour operating day framework. However, baseload units and others have runtimes, startup times, and startup costs that virtually dictate that they remain on for days or even weeks at a time. The consequence for CO_2 emissions is that these units run at minimum generation levels during off-peak times, and as noted above, the average CO_2 output rate is higher at minimum load than the incremental CO_2 rate in the optimal output range might otherwise indicate.

Recommendations

The auction and allocation design needs to support or accommodate the specific reliability requirements that arise because of the structure of the generation, transmission, and distribution systems. To the extent that units must respond to being called to meet local and system reliability rules, the system collectively will face an increasing opportunity cost over time if CO_2 allowances are consumed faster than expected. The monitoring system described below will have to be part of a larger system that will need to recognize upcoming needs for relief, either in the form of allowances or in the flexibility of compliance.

Compliance Challenges

Concerns

Generators may be unable to true-up to CO_2 production with allocated and auctioned allowances over the compliance window if NY experiences sustained extreme weather, if there is an extended outage of low-emitting capacity or transmission that delivers the energy of such capacity to load centers, or if load growth is higher than expected. In particular, sustained hotter-than-normal weather, an outage of low or zero CO_2 emitters, or their supporting transmission may well cause other generators to run through allowances at a higher rate than planned. Although the initial compliance period is three years, there is enough uncertainty in the process that generators might prudently plan compliance on a quarterly or even more frequent basis, consistent with reporting requirements and corporate commitments. Using future allowances to address what are perceived to be short-term needs for additional CO_2 production may result in reliability concerns if generation is significantly constrained in later periods. I am concerned that there is not a clear process for putting the CEMS information into context with load growth, outage, and extreme weather. While the cap and compliance period are set, it is prudent to have a process in place to anticipate and address extraordinary circumstances.

The uncertainty surrounding adjustments for extenuating circumstances will manifest itself in LBMPs and reliability costs, driven by allowance costs among other things. Factored into the marginal cost of power is the opportunity cost associated with foregoing future production and revenues. The opportunity cost stems from the limited availability of allowances. Producing now and consuming an allowance means that the allowance is unavailable for use in the future. It is possible that production now is necessary to meet reliability needs. However, unless there is some kind of monitoring and adjustment mechanism, production now may affect reliability adversely in the future.

<u>Recommendations</u>

I recommend that the monitoring process be expanded to include progress against assumed electricity production targets, incorporating adjustments for unexpected load and energy growth, extended outages of zero or low emitters or supporting transmission, and extreme weather. That process should have an appeals route by which, if actions to that point were prudent, but CO_2 allowance consumption exceeded expectations, a stakeholder committee could consider adjusting the compliance period, offset allowances, or other factors. The monitoring process needs to be continual and have frequent enough checkpoints that rational responses can be considered. Among the information to be considered is the status of future investments as well as forecasted usage rates of allowances.

Thank you for the opportunity to comment on the issue of allowance allocations and auctions. If I can be of further assistance or provide clarification, you may reach me by e-mail at jsavitt@alum.rpi.edu

Sincerely,

James H. Savitt, Ph.D.