AES
720 Riverside Drive
Johnson City, NY 13790

May 17, 2006

To: RGGI Staff Working Group

Subject: AES Comments on RGGI Model Rule

AES appreciates the opportunity to comment on the RGGI Model Rule. Our comments include those on specific aspects of the Model Rule as well as additional comments on general provisions of the RGGI program that are not specifically addressed in the Model Rule, but which provide the foundation for the rule. We support Greenhouse Gas reductions and would support an efficient and cost-effective RGGI program that works in concert with the ongoing evolution of the regional electricity market design. Given the initiative's stated goal to reduce overall greenhouse gas levels, we believe that offsets play a critical role that must not be artificially limited or arbitrarily circumvented. The following comments are provided in that vein – to improve the program, increase benefit to the public while decreasing costs and risks to electric system reliability.

It should be noted that there may be legal implications with respect to various aspects of the Model Rule. AES is not providing comment regarding such implications at this time. AES hereby expressly reserves all rights to assert limitations and any other claims with respect to legal authority applicable to any respective RGGI State's promulgation of rules derived from the Model Rule. Likewise, AES expressly reserves all rights to assert applicable federal law relating in any way to promulgation of and/or implementation, by the respective RGGI states, of the regulatory program outlined in the Model Rule and/or the RGGI MOU.

If you have any questions please contact me at (607)729-6950 (x4421).

Sincerely,

Chris Wentlent, Director
Regulatory Affairs

AES Comments on Draft RGGI Model Rule

Executive Summary

The proposed RGGI region has the most CO2 efficient, environmentally friendly generation portfolio in the United States. At the same time, the region has some of the highest wholesale and retail energy prices in the United States due, in part, to more stringent environmental requirements and an over-reliance on natural gas fired generation. Further, the region has specific identified generation shortfalls in the 2008 timeframe and known gas supply infrastructure and electric transmission limitations. It is critical that energy affordability, existing infrastructure reliability, and an ability to attract investment capital for new infrastructure (generation, transmission, and gas transmission) be maintained as this rule enters its final stage of development. A final rule that creates substantial cost disadvantages for in-region generation will result in several unintended consequences including a competitive advantage for generation from outside the region, increased environmental (NOx, SO2, Hg, and CO2) leakage from other regions, and less investment in the RGGI region at the very time when infrastructure is needed.

Critical issues which must still be addressed and therefore cannot be completely commented on are:

- Complete review of the leakage problems within the RGGI region and at the borders.

- Comprehensive reliability study to understand the real time reliability impacts on the northeast energy grid.

- Detailed discussion with energy and allowance traders to ensure any auction design adequately deals with the short, medium and long term needs of the energy marketplace.

- Detailed discussion with key capital investment firms to ensure the RGGI model rule can actually pass the litmus test of attracting new capital dollars to a region that is in need of additional infrastructure.

Ultimately, our regional goal must be a program that provides a fuel diverse, environmentally friendly generation portfolio that can adequately serve the energy needs of the region in an affordable manner and a CO2 model that is appropriately balanced to serve as a model for national policy. Accordingly, it is premature to request stakeholders to provide final comments until the aforementioned critical issues are fully evaluated.

Nevertheless, AES appreciates the opportunity to comment on the draft model rule as available to date. A number of issues associated with the Draft Model Rule and RGGI program as a whole are outlined below, starting with four issues of primary importance.

- First and foremost, the final Model Rule and state's implementing regulations should cap the size of the consumer benefit or strategic energy allocation to no more than

25%. To do otherwise would jeopardize the region's fuel diversity and electric system reliability.

- Second, the Model Rule should provide specific guidance to states on how to equitably allocate allowances to previously contracted plants that do not have the ability to pass on any of their costs to comply with the RGGI program.

- Third, the program should be reevaluated as it relates to how new units can be developed in the region without unduly impacting the ability of existing fossil units to remain viable (i.e., getting a sufficient allocation to remain competitive).

- Fourth, we encourage the states to remove unnecessary constraints on offsets. Offset use should be unlimited and not geographically constrained. Current CO2 technology is still in development stages and accordingly compliance options are limited to modest heat rate improvements, fuel switching, or reduced operation. CO2 is a global issue, requiring global solutions and to date, no one has provided any plausible reasons as to why economically or environmentally offsets should be limited.

Detailed comments on these and other issues follow.

- **Proposed Consumer Benefit or Strategic Energy Allocation** – The Model Rule specifies that at least 25% of the allocations will be assigned over to a consumer benefit or strategic energy purpose. Under the assumption that these allowances will likely enter the market through an auction, it must be noted that analysis provided to date to support an auction methodology has been at a high level at best and fails to accurately depict the market design of the deregulated marketplace or operational limitations faced by suppliers. Several presentations and papers have been provided throughout the RGGI stakeholder process demonstrating flaws inherent in this analysis, including the limited analysis of capital market financing terms and conditions, the failure to address infrastructure limitations, and the effect on long term energy contracts (e.g., see Mark Younger's presentation, "CO2 Allowance Allocation in Regional Greenhouse Gas Initiative" that was given at the 10/14/04 RGGI Workshop on Allowance Allocation, and "An Assessment of the Public Benefit Set Aside Concept Taking Into Account the Functioning of the Northeast/Mid-Atlantic Electricity Markets," dated 10/11/04 that was prepared for AES by Mark Younger. These documents can be found on the RGGI web page at http://www.rggi.org/docs/younger_pres_10_14_04.pdf and http://www.rggi.org/docs/aes_set_aside.pdf, respectively. To date, no document has been produced that refutes the critical points raised in these areas. As demonstrated in these papers, system reliability, fuel diversity, energy affordability, and adaptability to a national model will experience an immediate negative step change if this method is adopted on a large scale basis. Such advocacy basically ignores reality in support of a theoretical proposition that could have potentially drastic negative consequences to the viability of generating facilities that are critical for the maintenance of the region's electric system reliability and fuel diversity. It must be noted that an auction approach only has been attempted twice in the past – at much lower levels. The potential significant negative consequences are far too great to experiment with this largely untried approach**. As such, any consumer benefit or strategic energy allocation should be capped at no more than 25%.** Any change from the 25% set aside, at best, should be considered over a long term (25 year) phase-in period to ensure commercial arrangements, electric marketing contracts, and capital market confidence in our Northeast marketplace is protected.

- **Previously Contracted Plants** – RGGI related costs will constitute a new cost adder in the market. However, some plants with long term contracts to sell their electricity do not have the opportunity to modify their contracts to account for these new costs until the date of expiration of the contract. Contracts can be in the form of power purchase agreements or tolling arrangements. Some of these plants have contracts that expire well into the future (e.g., the contract for one AES plant in the RGGI region does not expire until 2030). AES has three contract plants within states that currently plan to be part of the RGGI program. The inability to pass through any RGGI compliance costs places a unique and severe financial burden on these plants, to the point of potentially jeopardizing the ongoing financial viability of facilities that are otherwise economic. These plants tend to be newer, exceedingly clean units. Natural gas-fired plants with tolling arrangements or with dispatch provisions in their contracts can be expected to have a secondary severe problem in that the marginal cost of CO_2 allowances are not borne by the party making the decision whether to dispatch the unit. Many of these facilities currently operate infrequently due to high natural gas prices and would receive a relatively lower allocation of CO_2 allowances under any historic baseline allocation scenario. However, if the power off-taker does not bear the allowance responsibility or see the allowance cost in its marginal cost of generation from the facility, they will likely call for the plant to increase its generation, since such a plant's power costs will be more competitive compared to other plants in the region that include the CO_2 allowance value in their marginal cost of generation. Any increased generation without the ability to pass through CO_2 allowance costs creates even more of an economic burden for these plants. Without provisions to provide full allocation needed to match emissions from contracted plants, RGGI could have the perverse consequence of most severely impacting the type of units that environmental considerations would want to incentivise. **Therefore, the Model Rule should be expanded to include a specific provision that provides for full allowance allocation (e.g., the average annual emissions during the baseline period) to contract plants, for the term of their contract.** For plants with tolling arrangements or dispatch provisions, this full allocation would need to include the allowances needed to cover any increased generation that could result as a consequence of RGGI (possibly through a set aside to cover this situation). In order to receive a full allocation, such contracted plants should be required to provide a clear demonstration of their lack of compliance pass-through capability to the appropriate designated regulatory agency. An alternative equitable solution for contracted plants with tolling arrangements or dispatch provisions would be to have the power off-taker be the entity that is allocated RGGI allowances and that has the obligation to surrender allowances at the end of the control period equal to the plant's

CO_2 emissions. In this way, the party bidding the unit into the ISO and making the decision to operate would see the full marginal production cost of the affected plant.

- **New Units** – In the Model Rule as currently drafted how can new units be developed with sufficient level of certainty to provide incentive for necessary investment (both debt and equity) while still providing for maintenance of needed existing generation resources? Current ISO reports (NY, NE, PJM) indicate the need for new generation capacity in the 2006 to 2008 timeframe. Since the RGGI IPM modeling was completed, New York Governor Pataki has started the State's Clean Coal Initiative, calling for new coal-fired generation in the state, increasing the likelihood that new coal-fired generation will be built in the region. Assume 1,500 MW of new clean coal fired generation and 2,500 MW of new combined cycle generation is added in the seven states addressed in the Model Rule. This equates to approximately 16 million tons/year = 13% of the 7-states' Phase 1 CO_2 budget of 121 million tons. Unlike SO_2 and NO_x, where backend controls can significantly reduce emission levels from new (and existing) units, there are no such controls available for CO_2. Indeed, while continued research and development is important, it does not appear likely that such technology will be commercially available in the foreseeable future. As such, a 3-5% new source set aside as has become routine in cap and trade programs would be entirely insufficient to provide sufficient allowances for new entrants in the region. A set aside large enough to cover new units would result in insufficient allowances for the fleet of existing units to ensure continued financial viability of units that are needed to maintain system reliability. The program construct under the draft Model Rule is adverse to the efforts of the regional system operators and State utility officials to assure resource adequacy. The draft Model Rule will inject additional regulatory and financial uncertainty into the wholesale markets thus deterring long-term investment in supply resources at the very time such investment will be needed. Given the scope and extent of resource adequacy initiatives within the wholesale markets affected by the RGGI program, the final program should be carefully tailored to enhance resource adequacy rather than burden these initiatives and therefore adversely impact system-wide reliability. **Therefore, it is suggested that new units be initially exempt from the program, until, at the very soonest, they develop a sufficient utilization baseline to derive their allowances from the normal allowance allocation process or allow such facilities to utilize 100% offsets to cover its position until cost effective control technology is available.** One hundred per cent (100%) utilization of offsets for new units results in financing certainty, economic resource adequacy solutions, and enhanced environmental benefits for the RGGI region. Absent a solution to this issue it is questionable if new units that are needed in the region will be built, increasing generation and emissions leakage.

- **Unnecessary Constraints on Offsets** – It is recognized that trigger events provide for some liberalization on the use and geographic location of offsets; however, the program should be changed to eliminate any constraints. CO_2 is a global issue and all stakeholders agree on this fact. A ton of CO_2 reduction derived through offsets, regardless of where they occur on the planet, provides equal value towards the goal of addressing global warming to a ton derived by generating facility emission reduction within the RGGI region. Thus, **there is no environmental or economic basis to artificially superimpose any percentage caps or geographic limitations on offsets.** Indeed, the proposed limits on the use and geographic location of offsets will produce two untoward consequences. First, then will reduce compliance options for generators thereby unnecessarily driving up compliance costs for the facilities themselves and, concomitantly, the region as a whole. These unnecessarily increased costs will achieve no global warming benefit. Second, they will result in less greenhouse gas reductions than would have been available if the use of offsets had been freely allowed and fostered. Therefore, the proposed constraint on the use of offsets from other areas of the country or the world is counterproductive and should be eliminated. In addition, there is no basis to apply a cap on the number or form of offsets that can be used by a plant for compliance purposes. The development of offsets at any and all levels should be encouraged. Further, unlimited utilization of offsets will serve as a proper bridge until technology options become available to the generation sector. Many business entities are now considering potential business expansions globally in climate control related activities. Unnecessary offset limits create additional business uncertainty and will actually detract rather than promote new investment in this area. If RGGI's ultimate goal is to promote a model for a national program, allowing an offset provision that does not provide full flexibility in use and development of offset projects will be counter to the foundations needed in a quality, national CO2 program.

Additional comments follow:

EMISSIONS CAP

- **Size of the Cap** – Subpart XX-5.1 will provide each state's allowance budget. These budgets are based on apportionment of the overall RGGI cap, which has been represented by the Staff Working Group as being modest in that it generally stabilizes emissions at current levels. With all due respects AES suggests that, in fact, the cap is very aggressive and needs to be increased. We fully recognize that the Staff Working Group has used a number of IPM model outputs in their evaluations. However, we believe that the tacit implication by many in the process that the "reference case" has greater validity as a projection of the future than does the "high emissions case" is a mistake. There are many reasons that have been elaborated by many stakeholders to believe that the "reference case" significantly underestimates future emissions and impacts of the RGGI program. These include, but are not limited to, the constraint on new coal-fired builds within the RGGI region, low gas price projections, gas supply and transmission infrastructure adequacy issues, optimistic assumptions on nuclear relicensing and renewables penetration, etc. In fact, since the modeling was completed, New York Governor Pataki has started the New York's Clean Coal Initiative, calling for new coal-fired generation in the state and several states have announced state specific command & control vs. national mercury trading programs to be effective in the 2010 timeframe. This demonstrates that the no new coal assumption used in the reference case is not realistic, and underestimates future CO_2 emissions within the region. Further, while labeled the "**high** emissions" case, in fact the set of assumptions used for the "high emissions" modeling runs (e.g., the same nuclear relicensing and renewables penetration assumptions as used in the reference case) may still result in an underestimation of future emissions and impacts of the program. **<u>As such, the cap is anything but modest, and should be reassessed based on realistic emission projections.</u>** The failure to allow offsets to be created for energy efficiency and demand side management programs magnifies this problem.

<u>ALLOWANCES</u>

- **Distribution of Proposed Consumer Benefit or Strategic Energy Allocation** –

  - <u>Frequency</u> – Due to the need for generators to hedge their power sales (i.e., acquire allowances needed for future power sales concurrent with the power sale) it is important that these allowances enter the market on a frequent basis. Since forward power sales occur throughout the year it's important for generators to have access to an available supply of allowances. Availability of 25% of total allowances on an infrequent basis (e.g., annually) can be problematic to the functioning of the electricity market for both supply and energy consumers. Therefore, it is suggested that allowances withheld for consumer benefit or strategic energy purpose be distributed into the market (by auction or any other process) on a frequent basis. It is suggested that this distribution be monthly (no less frequently than quarterly). Further, to facilitate the smooth operation of the market, the RGGI states are strongly encouraged to have a single, region-wide process for distribution into the market of allowances withheld for consumer benefit or strategic energy purposes as opposed to disparate, state-specific distributions**<u>. We strongly encourage the state working group to employ the expertise of energy and allowance traders to fully understand the needs of the energy marketplace including cash management, and credit requirements</u>**.

  - <u>Limit allowance offering to affected fossil generators</u> – With such a significant percent of allowances potentially being withheld for consumer benefit or strategic energy purposes, affected sources are going to be in a significantly short allowance position. They will need to acquire significant allowances to allow for continued operation and electric system reliability. It can be expected that little or no trading market will exist around the allowances allocated directly to sources (since generally all sources will be in a short position). Therefore, generators MUST be assured that they will have access to the allowances withheld for consumer benefit or strategic energy purposes. **<u>Therefore, the Rule should limit the initial offering (through auction, direct sale or any other mechanism used to place these allowances into the market) of allowances withheld for</u>**

<u>consumer benefit or strategic energy purposes to only affected fossil generators.</u>

- **Transition to a Federal Program** – Careful thought must be given as to how a regional program will be transitioned into a national program. Specifically, how will allowance transfer be handled to ensure any long term energy deals are not negatively impacted by a change of allowance provision? If not managed properly, it could have the unintended consequence of forcing buyers/sellers into shorter term energy deals to avoid this risk. Shorter term energy transactions create greater volatility for both buyers and sellers of energy.

- **Output-Based Allocations** – Subpart XX-8.8 (Additional requirements to provide net output data) provides information required to be supplied by sources in states that use energy output as the basis for allowance allocations.

  - While the title of the Subpart specifies "net" output data, Subpart XX-8.8(b) deals with states that require "gross" data. If a state decides to use energy output as the basis for allowance allocation it should have the discretion to use either net or gross output, the Rule should not dictate which metric to use. Therefore, the word "net" should be removed from the title of the Subpart.

  - If a state decides to use net energy output as the basis for allocations, the rule should include provisions to adjust for the parasitic load used to power air pollution control equipment in well controlled units. Specifically, in a net energy output allocation, the MWHs used to power flue gas desulfurization (FGD) and/or selective catalytic reduction (SCR) should be added to the unit's net energy output in allocation determinations. FGD and SCR processes use significant power. This power usage would not be recognized in an allocation based on net output. Without factoring in this consideration, a well controlled unit will receive significantly fewer allowances than a comparable uncontrolled unit. Having responded to the signals produced by other environmental initiatives by making substantial investments to install pollution control equipment, these units must not now be penalized for these decisions. Allocation processes should not reward units for *not* having SO2 and NOx pollution controls. Power usage for running air pollution control equipment is not an issue in gross energy output or heat input based allocations.

- **Biomass Firing**

  - <u>Conversion of Fossil Unit to 100% Biomass</u> – The Model Rule provides the mechanism for units that *cofire* biomass to derive appropriate CO2 credit under the RGGI program. However, there is no explicit mechanism for a unit to derive credit if it converts entirely to 100% biomass firing. Conversion of a unit to 100% biomass firing should be a legitimate and encouraged mechanism to comply with RGGI, especially for a multi-unit power station. As proposed, depending on a state's allocation mechanism, a fossil unit that converts to 100% biomass could possibly get a stream of allowances until it no longer has fossil heat input or generation in the baseline period – but not longer. It is suggested that a unit that converts to 100% biomass firing be treated as a fossil-fired unit throughout its life. That is, it should continue to receive its allocation based on the fossil fuel it had historically burned (i.e., prior to January 1, 2005), and that the avoided emissions should be allowed to be used as a compliance mechanism for the remainder of its life (i.e., it not be required to surrender any allowances during the years it burns 100% biomass). Such a provision is consistent with the cofiring provision, provides an incentive for an environmentally beneficial plant conversion, and provides a company with a legitimate additional compliance alternative to manage its fleet's overall RGGI CO2 emission reduction compliance requirements.

- Definition - The definition of "biomass" contained in the proposed rule should be expanded to include source separated, unadulterated construction and demolition fuel stocks. This source could provide a potentially significant supply of clean biomass. New York State recognizes this material as a qualified biomass source in its Renewable Portfolio Standard program. As provided in "New York State Renewable Portfolio Standard Biomass Guidebook", Chapter 2 - Eligible Technology and Feedstock Combinations (NYSERDA, April 2006), "The source-separated, combustible, untreated and uncontaminated wood portion of municipal solid waste or construction and demolition debris qualifies as an unadulterated resource and no special restrictions apply to these biomass fuels so long as the unadulterated biomass is not commingled with other wastes." The definition for biomass under RGGI should be consistent with, and no more restrictive than, what is called for in New York's RPF standard. It should be noted that Massachusetts is promulgating standards for construction and demolition material as a renewable fuel.

- Biomass Monitoring Requirements are Unnecessarily Burdensome – It is suggested that Subpart XX-8.5(d)(2) be modified to delete provisions that are unnecessary to determine CO2 emissions from firing biomass, as follows:

(2) *CO_2 Budget units that co-fire biomass.*

(i) The CO_2 authorized account representative shall report the following information to the REGULATORY AGENCY or its agent for each calendar quarter:

(*a*) ~~Chemical analysis~~ Carbon content and moisture content of biomass fired~~, including carbon content~~;

(*b*) ~~Moisture content of biomass for each shipment received for firing at the CO_2 Budget unit;~~

~~(*c*)~~ Total biomass fuel input (tons) to the CO_2 Budget unit;

(~~d~~c) Total biomass heat input on an as-fired basis to the CO_2 Budget unit;

~~(e) Heat input rate of biomass to the CO_2 Budget unit (MMBtu/hr);~~

~~(f) Fuel feed rate of biomass to the CO_2 Budget unit (tons/hr);~~

~~(g) Total operating hours for which biomass was co-fired;~~

(~~h~~d) CO_2 short tons emitted from the CO_2 Budget unit due to firing of biomass;

(~~i~~e) Description and documentation of fuel sampling frequency and methodology; and

(~~j~~f) Description and documentation of monitoring technology employed."

As an alternative to sampling each shipment or frequently analyzing as-fired samples, either the state or the facility (with state approval) should be allowed to develop generic factors (carbon content and heating value) to use if a biomass fuel is relatively consistent (for example, if a relatively uniform wood waste is the only biomass that is combusted).

- **Allocation Timing** – Subpart XX-5.2 specifies that allowance allocations for 2009 through 2012 will be determined by January 1, 2009. The Rule should encourage the states to determine allocations as soon as possible to enable plants to plan actions that will need to be made to facilitate cost-effective compliance with the program and allow the ability to enter energy transactions from 2009 and beyond. **Failure to resolve the allocation issue in a timely manner will create additional risk for both suppliers and consumers by placing both in shorter term, potentially higher risk markets.**

OFFSETS

- **Loss of Project Eligibility Due to Regulatory Change** – **It is recommended that the General Additionality Provision in Subpart XX-10.3(d)(1), that removes the eligibility for a project to receive offsets from the date that such an action is required by law, regulation or administrative or judicial order, be deleted.** At a minimum, such a legal/regulatory event should not trigger a project's ineligibility to receive allowances during the ten allocation years for which it applied for and was initially granted offsets – it could possibly be a rationale for not granting offsets for a second ten-year stream of offsets. Laws and regulations frequently change, and to subject a project's stream of offsets to such regulatory uncertainty adds such a level of risk that it could significantly reduce investment in such projects, dampening the availability and viability of the use of offsets within the RGGI program.

- **Lack of Definition of Spot Price for Trigger Points on Offset Use** – The program includes provisions for somewhat less restrictive use of offsets once the regional spot price for CO2 allowances equals or exceeds \$7 and \$10. However, it's not clear how the spot price will be determined. As noted elsewhere, it can be expected that there may be minimal trading of allowances allocated to sources due to the short position that generators will be in as a result of the large size of the proposed consumer benefit or strategic energy allocation. Price signals may only be available from potentially infrequent auction results. The mechanism for establishment of a twelve month rolling average allowance price needs to be determined. A recommended approach would be to hold allowance auctions on a monthly basis.

- **Oversight Considerations –** The program must have integrity if there is to be an effective market process. Offsets must be real, quantifiable and verifiable. The offset approval process needs to be open, transparent, consistent, fair and time sensitive.

- **Offsets From Projects Eligible For Other Incentive Programs** – Participants should be able to receive offsets for projects that are also eligible for other renewable or GHG incentive programs. It does not make sense that if a participant can derive revenue or make money from a project that furthers the objectives of RGGI, then it would not qualify for RGGI offsets.

<u>GENERAL ISSUES</u>

- **10% Reduction Between 2015 and 2018 -** The program includes two stages: (i) emissions stabilization from 2009 through 2014; followed automatically by (ii) a phased in 10% cut applied against the stabilization level. While the Memorandum of Understanding calls for a comprehensive review in 2012, such a review will be largely meaningless if the 10% level already has been set as a foregone conclusion. Indeed, a second phase 10% reduction goal is premature until the actual impacts of this program are fully identified, analyzed and quantified. A cautioned approach is especially important due to the key open IPM modeling issues identified below, including:
    - Degree of renewable penetration that actually will become commercial in the Northeast.
    - CO2 impacts of clean coal facilities which, due to Governor Pataki's Clean Coal Initiative, are much more likely than had been assumed during the RGGI IPM modeling.
    - Ability of gas infrastructure to provide the additional gas supply required in the future due to the increased dependence on natural gas facilities.
    - Actual gas pricing vs. RGGI modeling assumed gas pricing going forward, particularly in light of increased demand.
    - Ability of all existing nuclear facilities to secure relicensingpermits.
    - Continued ability to maintain fuel diversity and needed load following capability, particularly given the increased reliance on wind facilities.

- Actual load growth vs. RGGI modeling assumed reduced load growth levels due to general conditions and attributable to an increase in conservation levels.
- Continued construction of new generating facilities notwithstanding the projected reduced load growth levels.

Only upon a full review of the program, which is slated to occur in 2012, should any decision be made concerning whether an overall reduction should be mandated at some point in the future and, if so, the appropriate level of any such reduction. Thus, the parameters of the "second stage" should be left to be developed following completion of the 2012 review process.

- **Market Impacts** – During the August 31, 2005 and September 12, 2005 meetings, a number of questions were asked concerning the impact of a RGGI program on dual-fuel generating facilities. At both meetings, Karl Michael reported that these units were "kept on" during several of the winter months in the modeling runs. When asked if they would remain on absent this intervention in the modeling results, Mr. Michael indicated that they would not. This fact raises both reliability and market issues. Although not explicitly identified, in order for these needed units to continue to run, they must obtain reliability must run contracts. These contracts undermine the wholesale market structure, artificially suppressing prices. To date, New York has avoided the need to enter into these contracts. New England has taken steps to eliminate these contracts going forward. The market impacts that will result from being forced to resort to these contracts in the future must be fully assessed. This dynamic is counter to the objectives of recent resource adequacy initiatives such as structured market design and rule changes to correct the fledgling capacity markets in the Northeast.

- **Reliability Studies** - As the final rule is developed, the focus must remain on the cornerstone principle upon which this effort was initiated -- securing carbon dioxide emissions reductions while maintaining energy affordability, fuel diversity and system reliability through the creation of a program that will serve as the basis for a national program. In this regard, a fundamental shortcoming in the process that has been conducted to date must be raised. As became evident during the course of the discussions at the September 12, 2005 stakeholder meeting, all parties agree that the reliability impacts of any RGGI proposal must be fully identified and evaluated. Yet, notwithstanding the requests of many parties including the NYSRC and IPPNY, no reliability studies have been conducted to date.[1] In fact, as reported by Karl Michael during the September 12th meeting, the studies to date have been relatively high level and have not studied the system at the bus level – the level at which the evaluation must take place if reliability issues are to be uncovered. Any RGGI program has the

[1] For instance, the studies to date have shown a further shift to, and growing dependence on, natural gas facilities to meet load requirements. However, many organizations, including the North American Reliability Council ("NERC"), are warning that the electric industry's growing dependence on natural gas as a primary fuel for new power plants is an emerging area of concern. See Power Daily Northeast, "Growing Dependence on Natural Gas Emerging Concern," (September 6, 2005).

potential to have impacts that are far too widespread and irreversible to proceed without the benefit of full information in these areas**. Stakeholders cannot be in a position to fully comment on the model rule until such information is developed and released publicly.**

- **Emissions Leakage** - Units are dispatched by the market models based largely on economics. With an increased reliance on natural gas facilities, electric prices will be higher in the RGGI region than in the surrounding regions which will maintain higher levels of lower cost coal facilities. Transfer limits into the RGGI region will be maximized; generation levels within the RGGI region will be supplanted by a larger amount of imports. Due to the fact that power plant SO_2, NOx and Hg emissions from RGGI states are generally at lower levels than surrounding areas, reduced generation within the RGGI states as a result of the RGGI program could actually result in overall increased SO_2, NOx and Hg emissions within the entire Eastern Interconnect Region. Due to different emission characteristics between different plants and fuels, it is not possible to extrapolate SO_2, NOx and Hg emissions leakage from the data that has been released to date for CO_2.[2]

  We appreciate the fact that other air pollution control programs will help assure that SO_2, NOx and Hg emissions will be controlled; however, the nature of cap and trade programs will allow for leakage issues to arise in the RGGI region. For example, the Clean Air Interstate Rule (CAIR) caps SO_2 and NOx emissions over most of the Eastern U.S. but does not require that emissions will be controlled in any specific state or region (e.g., the Northeast) – only that, overall, reductions will occur within the Eastern U.S. Under SO_2 and NOx cap and trade programs, it is probable that some sources in states immediately upwind of the RGGI states will increase their import levels to the RGGI region, and hence, their emissions.[3] Similarly, the Clean Air Mercury Rule implements emission reductions through a cap over the entire nation. While the cap and trade provisions of this rule are being challenged, nothing in the promulgated rule assures that increased imports to the RGGI region will not bring with them increased mercury emissions into the region. Finally, it is understood that the Ozone Transport Commission is evaluating "CAIR Plus" emission reduction requirements throughout the Northeast. However, no details have been developed and there is no assurance that this initiative will protect against emissions leakage that may result from RGGI. **States participating in a RGGI initiative must carefully review whether SO2, NOx and Hg emissions leakage resulting from non-RGGI regions will negate any emissions reductions and perhaps even produce a net exposure to emissions within the RGGI region.**

[2] It is believed that this information could be derived from the model runs that have been conducted to date. At the September 12th stakeholder meeting, agreement was reached that this information will be shared with stakeholders so that the full impacts of a RGGI proposal on all environmental considerations can be assessed. To the best of our knowledge, however, this information has not yet been provided.

[3] We understand that the IPM modeling of RGGI has shown generation leakage from the PJM system; these are the same units that may increase emissions above their own states' emissions budgets under CAIR or similar other programs.

MONITORING AND REPORTING

- **Common Stack Issues Are Not Adequately Addressed**

  Subpart XX-8.2(c) is the only spot where common stacks are addressed in the model rule. Several AES plants have common stacks. There is no current requirement that CO_2 emissions be apportioned to the individual units feeding into the common stack. Because none of our common stacks have affected and non-affected units under the acid rain program, none of our plants have submitted a petition under the referenced provisions of 40 CFR 75.

  As with all allowance-based programs, a unit must hold enough allowances in its account to cover its emissions. However, CO_2 emissions are not monitored at the unit level. There is a requirement under 40 CFR 75 that the total stack heat input be apportioned among the boilers exhausting through the stack. CO_2 emissions could be apportioned in the same ratios, although this is not explicitly stated. Alternatively, compliance could be determined on an emission point basis, following procedures incorporated in 40 CFR 75 for situations where both affected and non-affected units share a common stack.

  Paragraph XX-8.2(c) also states that the administrator must approve a method to apportion CO_2 emissions between units sharing a common stack. Although it is not explicitly stated, 'administrator' usually refers to the EPA administrator. Since this is a state-initiated regional program, it must be questioned if EPA will take on the responsibility to approve the subject methods specific to the new issues raised above.

- **Monitoring Requirements Extraneous to CO2**

  Subparts 1.2(ab) and 8.1(a) discuss the installation and operation of continuous emission monitoring (CEM) equipment for monitoring and reporting CO_2 emissions under the RGGI program. However, references are made to CEM analyzers – such as NO_X – that are extraneous to a CO_2 program. In addition, the provisions seem to indicate that all sources must install O_2 and moisture monitors. It should be made clear that any of the monitoring requirements mentioned in the model rule – flow, CO_2, moisture, and O_2 – need only be installed if they are required to measure and report CO_2 emissions. For example, many power plants monitor and report CO_2 emissions under 40 CFR 75 by using a flow monitor and a CO_2 monitor measuring CO_2 concentrations on a wet basis. Since the flow monitor measurements are also on a wet basis, there is no need to require the installation and use of either a moisture or an O_2 monitor in this instance.

  Subpart 1.2(ab) should be modified to read as follows:

  > "(ab) *Continuous emission monitoring system* or *CEMS.* The equipment required under Subpart XX-8 to sample, analyze, measure, and provide, by means of

readings recorded at least once every 15 minutes (using an automated DAHS), a permanent record of stack gas volumetric flow rate, stack gas moisture content (if necessary), and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with 40 CFR Part 75 and Subpart XX-8. The following systems are the principal types of continuous emission monitoring systems required under Subpart XX-8.

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

~~(2) A nitrogen oxides emission rate (or~~ $\cancel{NO_X}$ ~~-diluent) monitoring system, consisting of a~~ $\cancel{NO_X}$ ~~pollutant concentration monitor, a diluent gas (~~$\cancel{CO_2}$ ~~or~~ $\cancel{O_2}$~~) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of~~ $\cancel{NO_X}$ ~~concentration, in parts per million (ppm), diluent gas concentration, in percent~~ $\cancel{CO_2}$ ~~or~~ $\cancel{O_2}$~~; and~~ $\cancel{NO_X}$ ~~emission rate, in pounds per million British thermal units (lb/MMBtu);~~

(~~3~~2) A moisture monitoring system, if necessary, as defined in 40 CFR 75.11(b)(2) and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O; and

(~~4~~3) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2.~~; and~~

~~(5) An oxygen monitoring system, consisting of an~~ $\cancel{O_2}$ ~~concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of~~ $\cancel{O_2}$ ~~in percent~~ $\cancel{O_2}$~~.~~"

Paragraph 8.1(a)(1) should be modified to read as follows:

"(1) Install all monitoring systems required under this subpart for monitoring CO_2 mass emissions. This includes all systems required to monitor CO_2 or O_2 concentration, stack gas flow rate, and ~~O_2 concentration,~~ heat input, ~~and fuel flow rate,~~ as applicable, in accordance with 40 CFR 75.13 and 75.72 and all portions of appendix G of 40 CFR part 75, except for equation G-1 in 40 CFR Part 75. Equation G-1 in Appendix G shall not be used to determine CO_2 emissions under this Part."