Initial* Questions and Comments on the Resources For The Future report "Allocations of CO2 Emission Allowances in the Regional Greenhouse Gas Cap-and-Trade Program", March 29, 2005

(* The following questions should be considered as possibly incomplete due to the short amount of time that has been provided for review prior to the April 6th RGGI meeting, coupled with the fact that only summary tables were provided so that it was not possible to do a thorough review of model outputs.)

1. Page 1 of the report discusses Updating and notes that two of the potential bases for determining the allocation under updating include "share of emissions, or share of heat input (related to fuel use) at a facility". Each of these could be characterized as the method used by New York for its state NOx and SO2 rules (6 NYCRR Parts 237 and 238, respectively) and the method used by most of the states in the NOx regional cap-and-trade program. Neither was modeled in the report. Why was an updating approach based upon a generators historic need for allowances not modeled?

2. The paper notes on page 3 that it does not consider secondary costs imposed outside the electricity sector due to changes in electricity or fuel prices. Do the authors believe that these factors are insignificant?

3. Please provide the basis for the conclusion on page 4 of the report that the CO2 allowances created by the program have a value that is <u>at least four times as large as the social cost of mitigation.</u>

4. Pages 8-9 of the report acknowledge that the modeling does not represent long term contracts for generators that are held by distribution companies but then claims: "However, in a post-transition competitive market, the contracts do not limit the electricity retailer's ability to charge a price based on marginal cost of electricity sold in shorter term markets. The reason is that the retailer who has purchased power under long-term contract with a generator could turn around and sell that power in the spot market where RGGI policy could be impacting costs of the marginal generator and thus it is the spot market price that defines the opportunity cost of selling power to retail customers."

    a. Does the modeling assume that the energy that distribution companies purchase under long term contracts will be passed through to customers at the spot market price?

    b. What is the assumed relationship between the rates paid by consumers and the market clearing price?

        i. Is the retail rate assumed to have a direct relationship to the percentage increase in the spot energy market price? For example, if the market clearing price increases by 10%, does the retail rate also increase by 10%.

ii. Alternatively, is the retail rate assumed to have a direct relationship to the numeric increase in the spot market price? For example, if the market clearing price increases by $5/MWh then the retail price increases by $5/MWh.

iii. Finally, is there some other relationship between the spot market price and the retail rate? Can the relationship be easily described?

c. If long term contracts do not benefit from increases in the spot market price, does the analysis overstate the benefit to the generator under contract and thus to the generation sector as a whole as a result of increasing spot market prices?

d. If distribution companies are not allowed to pass the spot market price through to their customers for their long term contracts then does the analysis overstate the cost to consumers from an increase in spot market prices?

5. Pages 10-11 discuss the representation of the RPS projects in the modeling. How does the model address the interrelationship between the spot market clearing price and the premium that the RPS resources are paid? Does the analysis assume that an increase in spot market costs will automatically result in an increase in payments to these projects?

6. Page 12-13 discusses the change in producer and consumer surplus that is included in the reporting for each of the cases. What is the estimate of the value for producer and consumer surplus that is estimated for the baseline case?

7. Page 13 notes that distributional consequences of different approaches are represented by showing the affect of market value of generating assets. The listed categories do not provide any results for oil or oil/gas units.

   a. Was oil fired generation modeled?

   b. If oil was not modeled, is it correct to estimate that the impact on oil units would be somewhere roughly between the estimated impact on coal and gas units for each case?

   c. How were requirements to burn oil for reliability reasons addressed?

   d. Does the analysis consider how these units would be treated if they cease to be economic as a result of the CO2 allowance allocation?

8. The report appears to focus on the social cost of the program for the entire nation (see pages ii, 4, and 19 and Table 4). Wouldn't it be more appropriate to focus on the regional calculations since the program is a regional program with a stated intent of being a model for a national program? Presumably, the inclusion of the

rest of the country would eliminate the leakage issues that drive the difference between the regional and national measures.

9. The conclusions for the Updating Bookend case appear to be largely driven by the choice to allocate the allowances to the emitting resources on the basis of their share of the generation from emitting generators. Is it correct that the result of this choice is to allocate more future allowances to the marginal gas generation than they consume? Essentially, the allocation rule would provide more than one ton of future CO2 allowance for each ton consumed today. Not surprisingly, the result is to lower the electricity price at the same time that the CO2 allowance cost is increased (this is shown in Figure 1 on page 52). It appears that an updating approach that is based upon a generator's need for allowances such as is used for the current NY SOx and NOx programs would not have such extreme impacts. In particular, is it correct that while the future allocation of the allowance would moderate the impact on consumer payments, it would not create the incentive to increase generation by the gas fired generators since there would not just be replacing the allowance they consumed today? Since updating based upon a unit's historic need for allowances is much closer to what is done today in a number of cap-and-trade programs, why wasn't it included in the analysis?

10. The baseline estimate of a negative Net Present Value ("NPV") for gas indicates that capacity market revenues and impacts for generators were not considered. Did the analysis include capacity markets that exist in the RGGI region? If the Analysis did include capacity markets then why does the analysis include a Negative NPV for any of the generators that were not retired?

11. Page 20 states that: "When all types of assets are aggregated together, the net present value of generation assets increases by about 35% under historic allocation and decreases slightly under an auction." This statistic appears to be determined dividing the average change in the Net Present Value ("NPV") of generation by the baseline NPV of generation. There appear to be problems with using the calculation in this manner. Exclusion of the capacity values for the resources results in understating the baseline valuations and therefore overstating the impacts of the change. Adjusting all of the generation valuations upwards by $375/kW to represent a situation where the capacity market provides sufficient revenue so that the existing gas units receive at least enough revenue to continue operating would provide a more realistic baseline valuation. Making this change reduces the claimed 35% increase in asset values for the historic allocation bookend case to an 11% increase.

12. Much of the analysis focuses on the impact on the aggregate generating class. While it is clear that nuclear and renewable generators, to the degree they are not selling their energy under some form of long term contract or RPS program, will have an increased value associated with any increase in energy prices from RGGI, it is unclear why this increased revenue should be counted as some kind of offset against the losses to the fossil generators. Many of these fossil generators are needed to provide fuel diversity and to provide reliability services such as load

following and ancillary services that cannot be provided by the other generation classes.

13. Table 3 (and many of the other tables) of the report presents the generation results for the Baseline and Bookend cases. While the table notes that the numbers may not sum due to rounding, there seems to be a category of energy supply that has not been listed. This table below, that is derived from Table 3, shows that between 40 and 49 GWh of generation has not been identified. Does the missing data represent some additional category of generation? If it is an additional category of generation then why does it change between the baseline and other cases?

RFF Modeling of Generation for Bookend Cases

	Baseline	Historic	Auction	Updating
RGGI Region				
Total	393	348	348	371
Coal	73	48	48	23
Gas	130	115	116	173
Nuclear	107	108	108	106
Renewable	34	40	40	32
Unknown Category(?)	***49***	***40***	***40***	***40***
Rest of Nation	4,847	4,885	4,886	4,861
Entire Nation	5,240	5,233	5,234	5,232

RFF March 29, 2005
Report, Table 3, page 36

14. The Rest of Nation results for the Updating Bookend Case appear somewhat anomalous when compared to the other Bookend Cases. As expected, the Historic Allocation and Auction casese result in higher prices in the RGGI region and therefore result in increased leakage. The leakage price impacts in the Updating case are substantially reduced, as is the estimate of leakage. Nonetheless, the impacts on consumer and producer surplus outside the RGGI region are almost as substantial in this case as in the other two Bookend cases. What causes this result?

15. Did the analysis determine whether under the difference scenarios any units would require an Out of Market Payment or a Reliability Must Run contract to enable the ISOs to assure reliability.

16. The analysis discusses Leakage but does not provide any direct calculations. In particular, the tables showing the scenario results present RGGI Region CO2 savings for 2025 and cumulative nationwide CO2 reductions . Is it possible to get the cumulative CO2 savings for the RGGI region for each of the cases?

    a. In the table below we have attempted to estimate the cumulative RGGI region CO2 savings that would result from the modeled reduction targets. Is this estimate correct?

	Without RGGI	With RGGI	RGGI Region Reduction
2008	124	124	0
2009	124.71	122.57	2.142857
2010	125.43	121.14	4.285714
2011	126.14	119.71	6.428571
2012	126.86	118.29	8.571429
2013	127.57	116.86	10.71429
2014	128.29	115.43	12.85714
2015	129	114	15
2016	130.40	112.60	17.8
2017	131.80	111.20	20.6
2018	133.20	109.80	23.4
2019	134.60	108.40	26.2
2020	136	107	29
2021	138.20	105.60	32.6
2022	140.40	104.20	36.2
2023	142.60	102.80	39.8
2024	144.80	101.40	43.4
2025	147	100	47
Cumulative RGGI Savings			376

    b. Assuming the above estimate is correct, does it follow that the estimated leakage for the Historic, Auction and Updating Bookend cases is roughly 175, 143 and 87 tons respectively.