TO: **RGGI Stakeholder Modeling Subgroup**

FROM: **Steve Clemmer, Union of Concerned Scientists;**
Derek Murrow, Environment Northeast

DATE: **August 20, 2004**

RE: **Comments on Renewable Energy Assumptions for RGGI Modeling**

This memo includes our comments on the renewable energy assumptions that are being considered for the RGGI modeling, as described in the July 21, 2004 PowerPoint presentation that was circulated to the RGGI Modeling Subgroup. These comments are consistent with the comments that we submitted along with other environmental group stakeholders to the RGGI subgroup on May 17, 2004, but provide additional detail.

In general, we would suggest using renewable energy resource and technology assumptions developed by NREL and DOE's renewable energy program offices, supplemented with local information where available, rather than using EIA's assumptions. While EIA has adopted some of NREL's assumptions and they have made improvements to certain assumptions over time, we believe many of EIA's renewable energy assumptions remain overly pessimistic and lack empirical justification. Attached is a presentation Steve Clemmer gave to NESCAUM in December 2003 that discusses some of the problems with EIA's assumptions. NREL also gave a presentation at this meeting that shows some of the differences between their assumptions and EIA's.[1]

With all due respect to EIA's competent staff, they are not renewable energy experts. NREL has far more knowledge, experience, and research to back-up their projections. In addition, NREL, DOE, and EIA are all in the process of doing research to improve EIA's renewable energy assumptions used in the National Energy Modeling System, particularly for wind power. We would strongly urge you to contact staff at these agencies to see if and when this new information will become available.[2]

We would suggest using renewable energy cost and performance assumptions from the most recent version of NREL's Power Technologies Databook.[3] DOE's Office of Energy Efficiency and Renewable Energy recently used these assumptions to analyze the impact of their R&D programs in the NEMS and MARKAL models and for the 2005 Government Performance Review Act (GPRA).[4] Finally, EIA tested similar assumptions in the AEO 2004 version of NEMS for a separate run called the "DOE Goals" case.[5] In our view, these assumptions better reflect potential improvements in cost and performance that would occur with continued R&D and increases in the production volume of renewable energy technologies stimulated by carbon reduction policies, renewable portfolio standards, and other policies.

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[1] Online at http://www.nescaum.org/projects/ne-markal/index.html

[2] We would suggest contacting Walter Short at NREL, Chris Namowicz at EIA, and Joe Cohen and Jim McVeigh at Princeton Economic Research Inc.

[3] Online at http://www.nrel.gov/analysis/power_databook/ These assumptions were originally developed by the Electric Power Research Institute for a 1997 report entitled *Renewable Energy Technology Characterizations*.

[4] Online at http://www.eere.energy.gov/office_eere/gpra_estimates_fy05.html

[5] EIA's assumptions for this case are described in *Assumptions to the Annual Energy Outlook 2004*, pp 135-137.

The following are more specific comments on the slides presented at the July 21 RGGI Modeling Subgroup meeting:

Slide 12

- We would urge you to include additional biomass technologies including co-firing, direct-fired, and biomass combined heat and power. These technologies are commercially available today and may have lower costs than biomass gasification in the near to medium term, particularly co-firing and CHP. In addition, co-firing would likely result in greater emission reductions per kilowatt-hour generated than gasification or other stand-alone biomass plants. This is because co-firing would directly displace coal whereas stand-alone plants would likely displace more natural gas generation on the margin. We would suggest using cost and performance assumptions for cofiring and direct-fired plants from NREL's Power Technologies Databook. Although some states like Connecticut have strict NOx emissions limits on biomass technologies, it is probably going to be necessary to model one set of technologies and costs to satisfy all the RPS requirements of the different states, so either a cost adder could be used for CT supply or the issue could be ignored.
- While it is reasonable to include fuel cells as an eligible technology, we believe that only fuel cells using renewable fuels should be eligible to meet regional renewable electricity standards. Connecticut does allow fuel cells powered by fossil fuels to qualify for the state's RPS, but we believe that the cost of this technology is high enough that the model will not chose it and thus the issue can be ignored for this analysis (this was the case in the CT IPM modeling effort).

Slides 13-14

- We would suggest using cost and performance assumptions for biomass gasification from NREL, which assume slightly lower capital costs ($1,650/kW in 2005 declining to $1,258/kW in 2020) and slightly higher heat rates in the early years and slightly lower heat rates by the end of the forecast (9730 Btu/kWh in 2005 declining to 8670 Btu/kWh in 2020).
- We agree that some sort of sustainability criteria should be used for biomass resources. While raising the cost is one option, another potential option would be to reduce the amount of biomass assumed to be available. However, we do not have a specific recommendation, as we are not familiar with the details of the XENERGY study to know what sustainability criteria may or may not be included in their estimates. We would also suggest considering the sustainability criteria developed by the biomass working group for the New York RPS proceeding to help develop assumptions. There should also be limits placed on the distance the biomass is transported or transportation costs should be added to fuel costs.

Slide 23

- We agree that EIA's learning curve for wind power is extremely conservative and should not be used. If NREL's learning rate is nominally conservative as stated in the slide (which we agree with), why not use it instead of taking the average between EIA and NREL?

Slide 24

- We would suggest using the assumptions developed for DOE's GPRA analysis, which are an update to the assumptions from NREL's Power Technologies Databook.[6] This analysis assumes slightly higher capital costs in the early years and lower capital costs in the future than the assumptions listed in slide 24, and lower O&M costs and considerably higher capacity factors in all years. In particular, the capacity factors that are proposed for the RGGI analysis appear way too low. By 2015, NREL and DOE project capacity factors for class 6 sites to increase to over 50% and class 4 & 5 sites to increase to over 45%. The projections for class 4 sites assume increased performance from taller towers, longer blades, and improved efficiency in line with DOE's R&D goals for low wind speed turbines. Some of these improvements lead to a higher capital cost for class 4 sites than class 5 and class 6 sites.
- It appears that IPM takes the weighted average of the costs and capacity factors by the resource potential in different wind classes. Using this approach would make higher quality sites that would likely be developed first look less economically viable and would make lower quality sites that would be developed later appear more economically viable. If possible, we would suggest characterizing the cost and performance by wind class rather than a weighted average to more accurately reflect the sites that will actually be developed.

Slides 22, 25, and 26

- As stated in our May 17 comments, we agree that NREL's updated wind resource assessment for the region should be used as the starting point for this analysis. We do not believe there is empirical justification for EIA's step curve that increases the capital costs of wind by up to 200% as regional wind generation increases. We do not believe that anything above a 50% cost increase is justified. In our view, it would be better to limit the amount of the resource available for development and apply lower cost increases to account for additional siting, transmission, and ancillary service cost that may be incurred as the penetration of wind increases.
- In our experience using NEMS, anything above a 50% cost increase is effectively excluded from the model. This means that up to 75% of the region's (and each state's) wind resource potential may be excluded from the RGGI analysis. Since the original data supplied by NREL already excludes environmental sensitive areas, urban areas, wetland, areas with slopes greater than 20%, 50% of forested areas, and other areas, the overall exclusion to the technical potential is probably on the order of 85-90%.
- Overall, we believe that this level of exclusion is very conservative. While this exclusion may be appropriate for NY based on the state's fairly large resource and input from developers, and for New England, where siting wind projects has been more difficult, the exclusion may be too stringent for states in the Mid-Atlantic/PJM. Earlier this year, the American Wind Energy Association estimated that developers are considering adding up to 4,800 MW of onshore wind and 400 MW of offshore wind in PJM over the next several years. For comparison, a 75% exclusion to NREL's wind resource data for this region would leave approximately 2,800 MW available for development in these states. We would suggest reducing the exclusion in PJM to at least 50% so the potential more closely matches plans by developers.

[6] Online at http://www.eere.energy.gov/office_eere/pdfs/gpra_fy05/appendix_l.pdf

- Given the considerable uncertainty over how much wind could ultimately be developed due to siting issues and the fact that there may be more interest and incentive to develop wind under a regional carbon reduction policy, we would suggest doing some sensitivity analyses on the wind resource potential. We would suggest using a 75% exclusion for NY and New England and 50% exclusion for PJM for one scenario and a 50% exclusion for the entire region as a sensitivity run. The exclusions should be applied to the NREL data on a state-by-state and wind class-by-wind class basis.

Slide 27

- We agree that the PTC will likely be extended by Congress and should be part of the reference case scenario. However, there's considerable uncertainty as to how long the PTC will be extended. Given the importance of this assumption to the economics of wind and biomass, we would suggest doing a few sensitivity runs. As part of the reference case, we would suggest assuming that the PTC is extended through 2006 and expanded to include other renewable energy technologies, as currently proposed in Congress. For a sensitivity run, we would suggest assuming that the PTC is extended throughout the forecast and expanded to include other technologies.
- While the face value of the PTC is currently 1.8 cents/kWh for 10 years, the after-tax value of the PTC can be worth a lot more to wind developers. In NEMS, EIA assumes a value of 2.8 cents/kWh for ten years, which is based on the face value of the PTC divided by 1 minus a tax rate of 36%.

Slide 28

- We would suggest using cost and performance assumptions for solar from NREL rather than EIA.

Additional comments

- For one of the policy scenarios, we would suggest modeling a regional RPS that is set at the level of the best state RPS in the region.