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To: Brooke Suter, Connecticut Climate Coalition
From: Bruce Biewald, David White and Geoff Keith
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Subject: Review of GHG Modeling for Connecticut

We have reviewed the modeling performed for the Connecticut Climate Change Stakeholder Dialogue (CCSD) group. As you and I discussed last week, we have focused exclusively on the modeling inputs and outputs. Our observations are listed below in order of decreasing importance.

In sum, the work is headed in the right direction, but there appear to be significant problems in this set of runs that should be addressed. (Electric system modeling is inevitably an iterative process.) The biggest problems are: unreasonably low gas price inputs and electricity price outputs, and a nuclear retirement scenario that assumes an unrealistic amount of fossil-fueled generation therefore overstating CO_2 emissions. These problems result in a bias against renewable energy. Each of them could be remedied with relatively simple changes to input assumptions, yielding a study that is far more useful from a policy-making perspective.

1. Natural Gas Prices

The near-term gas price inputs in the Reference Case are too low. These prices are much lower than recent prices in New England, lower than other projections and, oddly, lower than ICF's own projections in other recent modeling work. The gas prices for the Connecticut Climate Change Stakeholder Dialogue (CCSD) study were taken from the Energy Information Administration's (EIA) *Annual Energy Outlook* report. In contrast, ICF used detailed in-house analyses and forward market prices to develop gas price inputs in its August 2003 modeling for the New England Avoided Energy Supply Component (AESC) study group.[1] As shown in Table 1, the CCSD prices for 2005 are 37 percent below the AESC prices. The table also shows that the AESC prices for 2005 are very close to current prices in forward markets for 2005.

Table 1. Wellhead Gas Price Assumptions in CCSD and AESC Modeling ($2003/mmBtu)

Study Year	CCSD	AESC	12/15/03 Forwards
2005	$3.01	$4.74	$4.69
2009			$4.12
2010	$3.33	$3.98	
2015	$3.69	$3.65	
2020	$3.87	$3.80	

Both studies use wellhead prices from the Henry Hub. Prices shown in both studies have been converted to 2003 dollars at the inflation rate used in the study (1.7 percent).

[1] See: ICF Consulting, *Avoided Energy Supply Costs in New England*, prepared for the Avoided Energy Supply Component Study (AESC) Group, Final Report, August 21, 2003. These prices are reproduced from Exhibit 2-25 on page 36.

The "Combo High Gas" scenario modeled uses much more plausible gas price inputs (below the AESC prices in the near term but above them in the longer term). However, this run tells us little about the effects of higher gas prices, because these effects cannot be untangled from the effects of the CO_2 cap and RPS policies also modeled in this run. To understand the impacts of higher gas prices, a new Reference Case needs to be run with higher gas prices. Then the "Combo High Gas" case could be compared to the high-gas Reference Case.

We understand that there was a brief discussion of the gas price inputs within the dialogue group, and the stakeholders decided to use the EIA prices, perhaps for consistency with other studies. However, in our view, any benefits of consistency are more than offset by the costs in accuracy of using unrealistic gas prices. Notably, in the AESC work ICF checked the gas price inputs against recent actual prices to ensure that reasonable inputs were used, and this comparison was included in the final report (see Exhibit 3-4 of the AESC report). Such a comparison would have been useful to the stakeholders in this study.

The low gas prices in the CCSD modeling are cause for substantial concern, because they have such a large impact on other fuel and energy prices in IPM® (the model used for the Connecticut modeling runs). Most importantly, the low gas prices depress the model's projected electricity prices dramatically (as discussed below). Electricity prices directly affect IPM's® projection of electricity demand, power plant additions and retirements, the cost of renewable energy credits and other dynamics central to this study.

2. Electricity Prices

The near-term electricity prices projected in the Reference Case are even more unrealistically low than the input gas prices. Like the gas prices, the electricity prices are much lower than recent actual prices in New England and lower than all recent projections of which we are aware, including the projections in ICF's modeling for the AESC. Table 2 compares the Reference Case electricity price projections in the AESC study to the Reference Case projections in the CCSD study. Current prices in forward markets for peak energy delivered in New England in 2005 (in the range of $52 per MWh) are even higher than the AESC prices.

Table 2. Projected Firm Energy Prices in AESC and CCSD Modeling ($2003/MWh)

	CT Prices		NEPOOL Prices*	
Study Year	CCSD Study	AESC Study	CCSD Study	AESC Study
2006	$29.12	$46.51	$27.82	$44.15
2008	$30.65	$46.21	$29.32	$43.76
2010	$36.95		$35.66	
2013		$45.33		$43.17
2015	$43.38		$42.21	
2018		$45.33		$44.25
2020	$45.27		$44.84	

**For the NEPOOL prices, the AESC numbers include Connecticut, while the CCSD numbers do not. Note that the CCSD market price data does not specify a dollar year. Most of the model inputs are in 2000 dollars, so we have assumed that price outputs are also in 2000 dollars and adjusted them here to 2003 dollars.*

As with the gas price inputs, ICF checked the electricity price outputs against historical data in the AESC project, and this comparison appears in the final report.[2] Of course the AESC project was explicitly focused on costs, while the CCSD work has a broader focus. However, this difference in focus does not explain why more carefully researched inputs were not used in the CCSD study or why comparisons of both inputs and outputs to recent actual data were not presented to the stakeholder group.

As noted, electricity prices are extremely influential in IPM®. If it is not possible to perform new runs that produce more reasonable Reference Case electricity prices, it will be crucial to quantify the effects that these prices have on other model outputs. One probable impact of the low Reference Case electricity prices is an overstatement of the cost impacts of the various policies examined, because the costs of these policies are measured as price changes from the Reference Case prices.

3. The Nuclear Retirement Scenario

In the "no nuclear relicensing" scenario, the nuclear units in the Northeast are projected to retire when their licenses expire. The model responds to this scenario by replacing the nuclear generation *entirely* with fossil-fueled generation. (Also, for the draft Electricity Sector chapter a separate sensitivity analysis was performed offline to evaluate all-gas and all-coal replacement scenarios.) While fossil fuels would likely produce much of the replacement energy, it is unlikely that they would produce all of it. The balanced market response to nuclear retirements would include some level of increased energy efficiency and renewable generation. Further, a realistic non-relicensing scenario could include policy responses to the nuclear retirements, designed to mitigate the emissions impacts. The assumption that fossil-fueled generation would replace all the energy from retired nuclear plants overstates the likely emissions increases of this scenario.

4. RPSs versus Green Demand

Slide 13 of the October 30, 2003 "Assumptions for Connecticut Analysis Reference Case" indicates that "Grassroots demand [for green power] is only included for those states without an RPS." It is unclear why this is assumed. Customer demand for clean energy would include customers signing up for (and perhaps paying more for) green electricity products. In virtually all RPS states, retail suppliers are prohibited from marketing energy used for RPS compliance as a green product, and the New York RPS development process appears headed in the same direction. Green demand is likely to be relatively small, so this oversight is not likely to have affected the results of the RPSs scenarios much. But this is an important policy point that should be acknowledged in the final report. Moreover, focused education to promote the purchase of green electricity (like that discussed within the dialogue group) could lead to a bigger impact from green electricity purchases.

5. Emissions Shifting

In the scenario simulating a regional CO_2 cap, the model predicts a substantial shift in electricity generation from the study area to other states such as Maryland. The Maryland

[2] See Exhibit 2-27, page 39, ICF Consulting.

electric sector's CO_2 emissions go up by 25 million tons in 2020, compromising a full third of the CO_2 reductions achieved in the study area. As mentioned in the draft Electricity Chapter, a generation performance standard or other policy designed to minimize this type of "leakage" could help mitigate this problem.

6. New Coal-Fired Generation in Connecticut

The addition of new coal-fired generation in Connecticut (in the Reference Case) seems unlikely. In the AESC modeling work, IPM® forecasted all of the new capacity additions as gas (CC and CT), with no coal, even in the long term. This seems more reasonable given the historical climate for new plant development in Connecticut. The new coal plant that pops up in the Reference Case affects the findings of the study significantly. It contributes to a large increase in CO_2 emissions in the Reference Case, creating an unrealistic benchmark against which the policy cases are measured.

7. CO_2 Policy Economic Transfers

Simply looking at the price impacts of the CO_2 Cap scenario does not capture the whole economic picture. The CO_2 cap is projected to cause a substantial increase in market prices for electricity. If this is the only economic result that one looks at, the policy appears expensive. However, the price increase primarily represents a *transfer* of money from customers to generators. There are other ways to design the CO_2 policy that would not have this effect (e.g., auction some or all of the emission rights and use the revenues to fund renewables and efficiency). The final report should acknowledge the fact that the CO_2 policies modeled would result in a substantial transfer of wealth, and this transfer should be discussed in the context of the economic analysis. "Details" in the design of environmental polices can have enormous implications in terms of wealth transfers, and these implications should not be glossed over.

8. Incomplete Information Provided

It is difficult to assess a number of things in this analysis, because certain pieces of information have not been provided. The most important missing items are the following.

Plant Retirements. When you are focused primarily on future emissions, plant retirements can affect the results significantly. A policy that causes the retirement of older plants is likely to have a much bigger emissions impact than one that simply results in fewer new (clean) plants. Modeling plant retirements with an optimization model is difficult, so modelers tend not to want to provide those outputs. But you need to see the plant retirements to get a full picture of the emissions results.

Electricity Production Costs. As we understand the fundamental objective of the IPM® (the model used for the Connecticut modeling runs), it minimizes the total cost of providing electricity. Since cost is the parameter optimized, it should be reported. The economic results presented (sheet five of the standard Excel reports) focus exclusively on market price. It would be extremely useful to see the production costs for each scenario, broken out by capacity investments, fuel costs, and fixed and variable O&M costs. (A review of the production costs would no doubt shed light on the low electricity prices generated by these runs.)

Assumed Reserve Margins. The reserve margins in the later years of the study period are probably too low. Slide 33 of the Power Point file "CT Assumptions 101.30.03s" indicates that the minimum reserve margins assumed for NEPOOL fall from 17 percent in 2005 to 13 percent in 2011 and remain at 13 percent after 2011. Actual reserve margins have not been provided, but we assume that the model is building capacity efficiently and actuals are close to these numbers.

While electricity restructuring is likely to result in lower reserve margins than those that regulated utilities have historically maintained, it is unlikely that reserve margins will be allowed to drop as low as 13 percent. In the wake of the California energy crisis and the August 2003 blackout, there has been strong interest in (a) maintaining adequate reserve margins and (b) replacing the voluntary NERC operating guidelines with mandatory ones. Several ISO's currently operate under mandatory procedures established by independent state bodies. For example, the New York State Reliability Council sets a mandatory reserve margin annually, which the NY ISO must implement. Currently that margin is 17.5 percent.