NRG

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March 21, 2007

Ms. Wendy Jacobs
Bureau of Air Management
Department of Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

Dear Ms. Jacobs:

On behalf of its operating subsidiaries in Connecticut, NRG Energy, Inc. ("NRG") hereby submits comments on, and answers to, the questions raised during the Department of Environmental Protection's ("DEP" or the "Department") February 27, 2008 stakeholder meeting on a proposed High Electric Demand Day ("HEDD") program. NRG operates approximately 1,800 MW of generation in the State that could be affected by a HEDD program. NRG's generating units comprise a combination of seven load following boilers and eight combustion turbines.

The impact of the HEDD program on NRG's resources can be significant from operational, environmental and financial perspectives. For this reason, NRG is submitting information for the DEP's consideration in developing a statewide HEDD program that combines cost-effective reductions with short and long term goals for affected resources, while still maintaining the integrity of the generation system to provide reliable electricity within the State.

NRG looks forward to continued discussions with the Department regarding the HEDD program, and is available to answer any questions the Department may have.

Please feel free to contact me at (860) 343-6962.

Very truly yours,
NRG ENERGY, INC.

Cynthia L. Karlic

Cynthia L. Karlic
Regional Environmental Manager

Attachments

Cc: w/Attachments
Mr. Richard Rodrigue
Bureau of Air Management
Department of Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

NRG Energy, Inc.
Comments on a Proposed High Electric Demand Day Program

NRG Energy, Inc. ("NRG") submits the following information to aid the Department of Environmental Protection ("DEP" or the "Department") in the development and implementation of a High Electric Demand Day ("HEDD") program in the state. The Department is a signatory to the Memorandum of Understanding ("HEDD MOU") dated March 2, 2007, in which the State agreed to a 25% reduction in NOx emissions from HEDD units (equivalent to 11.7 tons per day) on high electric demand days.

NRG addresses below the six questions posed by the Department at its February 27, 2008 stakeholder meeting (the "February 27th Meeting"), as well as other issues not raised during the February 27th Meeting.

As the Department is aware, NRG was active in the Ozone Transport Commission ("OTC") process during which the HEDD MOU was developed. NRG worked directly with the Department on a voluntary HEDD program for NRG's generating units in the State. While NRG is disappointed that the voluntary program was not adopted, NRG remains committed to the development of a HEDD program that will ensure reductions of nitrogen oxide (NOx) emissions as well as maintain a stable, financially sound generating system in the state.

NRG owns several generating units that fall under the category of load following boiler ("LFB") or combustion turbines ("CTs"). The list of NRG's units, their fuel type(s), size, and NOx control systems is included as Table 1.

Question 1

"Given multiple pollutants and energy market changes, are there critical timing issues we should be aware of in establishing shorter term and longer term objectives?"

Three major energy market developments must be considered, not only in drafting the HEDD regulations, but also in establishing the effective date of the HEDD regulations: new capacity procured as a result of the State's Energy Independence Act, new capacity procured as a result of Section 50 of Public Act 07-242 ("Section 50"), and implementation of the ISO New England Inc. ("ISO-NE") Forward Capacity Market ("FCM"). In addition, two other developments will affect demand and nitrogen oxide ("NOx") emissions: Round 2 of Project 100 resources procurement and the Department's proposed use of RGGI revenues.

Existing energy and environmental regulations, programs and goals should be given equal consideration in order to avoid disrupting the generating system, adding unnecessarily to the costs of operations, and implementing duplicative requirements.

Energy Independence Act RFP for Generating and Demand Resources

During the spring of 2007, the Department of Public Utility Control ("DPUC") selected four projects as the winning bidders in its Request for Proposal ("RFP") for new capacity under the Energy Independence Act. The DPUC issued the RFP as a means to reduce federally-mandated congestion costs in the State. In total, the winning bids will provide 787 MW of incremental capacity to the grid, with 782 MW of such incremental capacity being derived from three generation sources: a 620 MW base loaded natural gas fired combined cycle plant, a 66 MW oil-fired peaking facility, and a 96 MW natural gas fired peaking facility. The 66 MW facility is operational and the other two facilities are scheduled to be operational no later than 2011. The final 5 MW procured will be derived from a statewide energy efficiency project.

Adding 787 MW of incremental capacity may affect the operations of the LFBs and CTs and, therefore, daily NOx emissions in the State. Accordingly, the Department must consider the potential impact of this incremental capacity in its development of the HEDD program.

Section 50 Peaking Proposals

The second major development is the proceeding being conducted by the DPUC to implement the requirements of Section 50. Under Section 50, Connecticut Light and Power Company ("CL&P") and The United Illuminating Company ("UI") were required to propose, and other parties may propose, peaking generation projects to be constructed within the State. Section 50 requires the DPUC to approve proposals that are in the interest of ratepayers. Based on the DPUC's preliminary analysis, a minimum of 500 MW of peaking generation may be added in the State.

In its Section 50 proceeding, the DPUC received 11 proposals for peaking generation. A summary of the proposals is included as Table 2. As shown on Table 2, the majority of the proposed projects has a commercial operation date of June 2010, with a few of the proposals having later in-service dates. The DPUC is reviewing the proposals and must render a decision on the proposals by July 1, 2008.

The projects accepted in the Section 50 docket will typically operate during times of "peak" demand, which most likely will correlate with HEDD events. As shown by the Department's charts from the February 27th Meeting, the majority of the summer operations of LFBs and CTs occur on days with high electric demand, and these days typically correspond with a measured exceedance of the 8-hour Ozone standard in the State. The output of any new peaking generation can be expected to displace some of the generation now provided by the LFB and CT units at the heart of the HEDD issue. Hence, in developing its HEDD program, the Department must consider the impact of the amount, location and emission characteristics of generation selected by the DPUC in its Section 50 proceeding.

Forward Capacity Market

Implementation of the ISO-NE FCM and the Forward Capacity Auction ("FCA") is the third major energy market development that should be considered by the DEP in drafting a HEDD program. The purpose of the FCM is to provide 100% of New England's Installed Capacity Requirement through an auction conducted three to four years in advance. Once an owner's bid for capacity is accepted in the FCA, that owner has an obligation to deliver that level of capacity (measured in MW). Failure to deliver carries severe financial penalties on the owner. The first FCA, for deliveries in the June 2010 through May 2011 capability period, took place in the first week of February 2008.

An additional environmental compliance requirement, such as a HEDD program, will likely impose additional capital and operating costs and could have an impact on the financial and operational viability of the LFBs and CTs with delivery obligations in the FCM. In considering the effective date for a HEDD program, the Department should take into account the long lead times associated with the FCM, and the existence of commitments to financial terms, for resources to provide capacity three or more years in the future.

The second FCA, for the delivery period of June 2011 – May 2012, is scheduled to take place in December 2008. Although the second FCA will not take place until December 2008, certain key milestones related to the second FCA have already passed, significantly limiting the flexibility of generators to exit the market or incorporate environmental upgrade costs in their offers.

As currently outlined, the Department plans to have its draft HEDD regulations issued for public comment in September 2008. The qualification submissions for the third FCA (for the June 2012 – May 2013 delivery period), in which participants can reflect the costs of new requirements pursuant to the HEDD program, are due to ISO-NE by March 3, 2009. Without final HEDD regulations in advance of that date, resources will not be able to fully determine an accurate price for their capacity when committing to provide capacity services in 2012/13.

Round 2 of Project 100 Resource

On March 26, 2007, the Connecticut Clean Energy Fund ("CCEF") announced the selection of 11 renewable projects in the State in Round 2 of Project 100. Project 100 is a program managed by CCEF, as mandated by the State legislature, to develop not less than 100 MW of renewable generation in the State. CL&P and UI are required to enter into long-term power purchase agreements with the developers of the projects. The projects selected in Round 2 represent approximately 160 MW of new generation in the State.

The Department needs to consider whether the Round 2 Project 100 projects will operate on high energy demand days, potentially displacing some generation from LFBs and CTs, and, in turn, reducing NOx emissions on those days.

Use of RGGI Revenues

Under the Department's proposed regulations to implement the Regional Greenhouse Gas Initiative ("RGGI"), 91% of the approximately 10.7 million CO2 allowances annually allocated to the State (which equates to about 9.7 million auctioned allowances per year) will be auctioned. The proposed RGGI regulations mandate that approximately 23% of the auction revenues be turned over to CCEF to further develop renewable projects and approximately 70% of the auction revenues be turned over to CL&P and UI for energy efficiency projects.

Using the proposed reserve price of $1.86 per allowance, approximately $18 million per year will be raised, with about $4.1 million going to CCEF and $12.6 million in the aggregate going to CL&P and UI. Trades for offsets, RGGI allowance options and 2009 allowances in the secondary market have been in the $5-$10 range. Higher revenues will provide even greater funds for the renewable and energy efficiency programs.

The Department must consider the additional renewable and energy efficiency projects that may be constructed using to the additional funding, and the effect that such construction will have on NOx emissions on high energy demand days.

Question 2

"Should there be one reduction target developed or should there be decreasing reduction targets over time?"

The Department should develop a single reduction target. Based on NRG's response to Question 1, the numerous regional and State programs require implementation time and, subsequently, time must be allotted to assess the corresponding NOx emissions reductions.

Furthermore, the Department must also consider NOx emissions reductions that may be achieved through a revision of the NOx Reasonably Available Control Technology ("RACT") regulations. Although the Department has decided to re-evaluate the proposed revisions, NRG believes that revised RACT regulations will reflect lower NOx rates than those currently in place. Since any reductions required under revised NOx RACT regulations will be imposed on fuel burning sources in general, and not just on LFBs and CTs, the expected NOx RACT reductions must be considered when implementing a HEDD program. Failing to consider such reductions could cause the small universe of HEDD sources to expend dollars on control projects that may return little in NOx reductions.

Finally, on March 13, 2008, the EPA issued its revised primary and secondary ozone standards. DEP is required to determine the attainment status in the State by March 2009, obtain EPA approval of the designation by March 2010, and then to file the State Implementation Plan ("SIP") in 2013. At this time, the Department has not rendered a decision on attainment/non-attainment status in the State based on the revised standards or, therefore, on any required, future reductions. Hence, establishing a decreasing reduction target in a HEDD program at this time may be futile. Based on the work required on a SIP, the Department may find that the decreasing, further reductions are neither needed nor required as part of the SIP. Much more certainty will be provided to HEDD resources if the Department establishes one target reduction at this time, and then incorporates any future HEDD reductions into the SIP, rather than having a "future potential change" looming on the resources.

Question 3

"What types of emission units should the program apply to?"

NRG agrees that LFBs and CTs should be included in the HEDD program. Although there is a common understanding of what is meant by LFBs and CTs, the Department should define these categories to provide clarity regarding the resources that will be included in the program. For LFBs and CTs, NRG suggests a definition similar to the "Baseline Electric Generating Unit" definition found in 22a-174-22b, Post-2002 Nitrogen Oxides Budget Program, revised to include a capacity factor limit, so that only the LFBs and CTs of concern are included in the HEDD program. NRG recommends, a three-year average capacity factor no greater than 10% with no individual year greater than 20%, similar limits found in the federal definition of a Peaking Unit.

NRG operates four, dual-fuel 40 MW CTs at NRG's Devon Station (the "Devon units"). The Devon units are equipped with water injection and are limited by permit to 45 ppm NOx on liquid fuel and 25 ppm on natural gas. Depending on the design of the HEDD regulations, the Devon units may or may not be regulated by the HEDD program. If the Department chooses to regulate HEDD units based on a firm NOx rate, in concert with the proposed revisions to the NOx RACT limit for such units, then the Devon units should not be included in a HEDD program. Similarly, if the Department chooses to regulate HEDD units by requiring control technology on the various HEDD units, then the Devon units should be exempt from the HEDD program because water injection equates to an acceptable control technology for CTs. If the Department, however, chooses to establish a HEDD program based on a portfolio tonnage or rate cap then, the Devon units should be included in the HEDD program.

Question 4

"For assuring the HEDD emission reductions occur and are maintained, what limits should be applied?"

DEP should set emission reduction limits that correspond to, and that are developed in conjunction with, any changes in the NOx RACT limits. Because the Department has suspended the latest version of the proposed changes to the NOx RACT limits, NRG is not proposing such limits in this document. However, the emission limits that are placed on HEDD units should be no less than the limits that are included in the final, revised NOx RACT regulations. In addition, and as discussed below in NRG's comments regarding Question 6, the Department must include a large amount of operational flexibility to sources in the HEDD program. "Hard" limits (i.e., ones that must be attained without the use of NOx credits or allowances) or technology limits (i.e., SNCR for LFB and water injection for CTs) must not be forced on the units as part of the HEDD program. To do so, in the absence of final, revised NOx RACT regulations, would amount to merely imposing NOx RACT regulations on the HEDD units while ignoring the entire universe of resources covered by the NOx RACT regulations.

Question 5

"Which pollutants should be addressed?"

The HEDD program should regulate only NOx emissions, consistent with the terms of the HEDD MOU. Although the potential exists for increases in other pollutants due to the installation of NOx control equipment (e.g., CO in the case of water injection installation, particulates in the case of SNCR or SCR installation), such increases may be addressed in any needed permitting actions. NRG's comments on permitting of control equipment are included below in the "Other Issue" section of this submission.

Question 6

"What is the most cost-effective approach?"

The most cost-effective HEDD program is one that results in NOx emissions decreases, allows resource operators flexibility in their compliance options, and maintains the integrity of the electric generating system in the State. In addition to considering the energy market developments and the types of resources that should be included in the HEDD program, the Department must consider the schedule for revision of the NOx RACT regulations, the correlation between HEDD events and actual NOx emissions from HEDD units, the mechanisms listed in the HEDD MOU that could be used to implement the HEDD program, and a schedule to implement the HEDD program.

Based on these factors, together with the five regional and State market developments discussed in Question 1, NRG suggests a two-phased approach to implementing the HEDD program. The first phase would be implemented no sooner than the 2010 Ozone Season with the second phase implemented no sooner than 2012 Ozone Season. These implementation targets are consistent with the terms of the HEDD MOU, which states that the reductions should be ". . . achieved beginning with the 2009 [O]zone [S]eason or as soon as feasible thereafter, but no later than 2012."

First Phase

The first phase of the HEDD program would establish a portfolio tonnage cap or NOx rate limit based on the resources in a given "portfolio" as of the 2010 Ozone Season. A portfolio would be defined as all HEDD sources held by a single owner or operator. Once the limit measurement is chosen (rate or tons), an owner/operator would determine daily compliance with the limit for each HEDD event in the Ozone Season based on actual operations. The owner would "true-up" any calculated excess NOx emissions through the retirement of NOx allowances or credits, payment into a NOx Trust Fund (to be established), or offsetting mechanisms such as generation from renewable resources and implementation of energy efficiency projects not related to actual generating units.

NRG selected the 2010 Ozone Season as the HEDD program start date based on several factors. In addition to recognizing the developments discussed above, the implementation date must be one that resource owners/operators can meet through the installation of controls, as part of a compliance strategy, if so desired. For generating resources, a maintenance outage, planned through ISO-NE, would be required for controls installation. Typically, a generator will schedule a three week outage, but a five to six week outage is estimated to be required to install NOx controls. Each generator proposes to ISO-NE, during the summer, its scheduled outage(s) for the following year. ISO-NE evaluates scheduled outage proposals and determines, based on system demands and other resources' outage requests, the final system-wide outage schedule. Customarily, the system-wide outage schedule for the following year is finalized in the last quarter of the current year. Given the Department's goal of having draft HEDD regulations issued for public comment in September 2008, NRG believes that there may be insufficient time for generators to revise their scheduled outage proposals to ISO-NE, or to engineer and procure any controls equipment for installation, prior to the 2009 Ozone Season.

Furthermore, the Department has recently suspended the comment period for the revised draft NOx RACT regulations to allow for a second, internal DEP review. Resource owners must evaluate any changes to the NOx RACT regulations in concert with HEDD regulations to determine the best NOx control strategy from the perspectives of cost, implementation and timing.

DEP also must weigh the benefits of a portfolio rate limit versus a portfolio tonnage cap limit to decide upon the best strategy for reductions. Although the HEDD MOU is based on a percent reduction in tons, tons emitted and electric demand do not necessarily correlate. Figure 1 shows an evaluation of the NOx emissions from the NRG-owned HEDD units versus the ten highest demand days in the Department's February 27th Meeting presentation. As shown in Figure 1, while demand (measured in MWh) varied by approximately 9%, tons emitted varied by 61%; and, as MWH decrease, NOx tons did not correspondently decrease. In fact, the fourth highest tons emitted occurred on the tenth highest demand day.

Second Phase

NRG recommends that second phase of the HEDD program start no sooner than the 2012 Ozone Season, because several of the market developments described in Question 1 will have been fully implemented and the results, in terms of reduced NOx emissions, should be known. However if final HEDD regulations are not issued prior to the December 2008 FCA then, the second phase should not begin until the 2013 Ozone Season.

The second phase would set a daily NOx emission limit that must be met by each type of HEDD unit to meet the HEDD MOU 25% NOx reduction goal without the use of portfolio averaging or NOx credit and allowance use. However, NRG believes that site averaging should be allowed as a cost effective method for achieving NOx emissions reductions. The rates NRG proposes are those in a range contained in the draft revisions to the NOx RACT regulations: 0.17 lb/MMBTU for boilers with a rating greater than 250 MMBTU/hr and 50 ppm for combustion turbines using liquid fuel and 25 ppm for combustion turbines using natural gas.

Other Issues

Three additional issues should be considered by Department in developing the HEDD program: a description of a HEDD Event, permitting requirements for NOx Control Projects, and expedited permitting, if permitting is needed.

Definition of a HEDD Event

The HEDD regulations must define a HEDD event in a timely manner and with sufficient clarity to provide resource operators with certainty regarding when or if to modify their operations. In addition, the definition of a HEDD event will determine compliance with the Phase 1 and 2 as described in our response to Question 6.

A definition of "HEDD event" should incorporate two factors that are the basis of the HEDD MOU: air quality and system demand. Initial notification of a HEDD event should be based on the current Departmental system used to notify peaking units of a potential "Ozone Event", i.e., predicted eight hour ozone levels are forecasted to be "unhealthy for sensitive groups," "unhealthy," or "very unhealthy." By receiving this notification, resources would know that the potential exists that there will be a HEDD event and take appropriate actions.

An actual HEDD event declaration would be determined after the final ISO-NE demand levels are issued for any day when there was an Ozone Event. The ISO-NE demand level should be set at 26,000 MWh, which is the rounded demand day level for the 10^{th} highest demand day over the past three calendar years, listed in the Department's February 27^{th} Meeting presentation.

Permitting Requirements for NOx Control Projects

NRG also respectfully requests that the Department issue a response to NRG's letter of June 25, 2007 recommending that the need for permits for NOx control project be based on "future projected emissions increases" and not "future potential emissions increases," as those phrases are defined in the Department's regulations. This is a critical issue to moving forward with control projects, because the installation of an SNCR could result in an increase in particulate emissions over the 15 tons per year limit. Similarly, the installation of water injection can result in an increase in CO emissions over the 15 tons per year limit.

Expedited Permitting

As part of any HEDD regulations, the Department must include a method to provide expedited permitting for any resource that may require a permit to enable the installation of controls. If, in fact, the Department believes that any increases in emissions due to the installation of controls is attributable to future, potential emissions, then almost all installations of SNCR, SCR and water injection will require a permit. Given the potential workload increase for the Department, expedited permitting must be afforded to these units unless the Department is willing to waive the compliance dates for equipment installation that is not completed due to delayed permitting.

TABLE 1

LIST OF NRG UNITS POTENTIALLY SUBJECT TO HEDD REGULATIONS

Name	Fuel	Type of HEDD unit	NOx Controls	Comments
Branford 10	Kerosene	CT	None	
Cos Cob 10	Kerosene	CT	None	Water injection to be installed by 6/1/08
Cos Cob 11	Kerosene	CT	None	Water injection to be installed by 6/1/08
Cos Cob 12	Kerosene	CT	None	Water injection to be installed by 6/1/08
Devon 10	Kerosene	CT	None	
Franklin Drive	Kerosene	CT	None	
Middletown 2	Natural Gas and No. 6 oil	LFB	High Energy Reagent System	
Middletown 3	Natural Gas and No. 6 oil	LFB	Combustion Tempering and SNCR	
Middletown 4	No. 6 oil	LFB	Low NOx Burners	
Middletown 10	No. 2 oil	CT	None	
Montville 5	Natural Gas and No. 6 oil	LFB	Low NOx Atomizers	
Montville 6	No. 6 oil	LFB	Low NOx Atomizers	
Norwalk 1	No. 6 oil	LFB	SNCR	
Norwalk 2	No. 6 oil	LFB	SNCR	
Torrington Terminal	Kerosene	CT	None	

LFB = Load Following Boiler

CT = Combustion Turbine

TABLE 2

LIST OF PEAKING PROPOSALS UNDER SECTION 50

Owner	Site	Summer Megawatts	Primary Fuel	Commercial Operation Date
CL&P	Lebanon	200	Diesel	June 2010
CL&P	Waterbury	65	Natural Gas	February 2010
FirstLight Power	Southbury	100	Natural Gas	June 2011
PSEG Power	New Haven	134	Natural Gas	June 2011
UI/NRG	Devon	194	Natural Gas	June 2010
UI/NRG	Middletown	194	Natural Gas	June 2010
UI/NRG	Montville	97	Kerosene	June 2010
Maxim Power	Bridgeport	96	Natural Gas	June 2012
Maxim Power	New Haven	170	Natural Gas	June 2012
Bridgeport Peaking Power	Bridgeport	200	Natural Gas	June 2010
Bridgeport Energy II	Bridgeport	350	Natural Gas	November 2010

Figure 1 - HEDD Demand vs. NOx Tons