Comments of NRG Energy, Inc.
on the Draft Report
"Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)"

Introduction

On June 17, 2008, the Connecticut Department of Environmental Protection ("Department" or "DEP") made available for public comment the draft report prepared by Synapse Energy Economics, Inc. ("Synapse") entitled "Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)" (the "Report").

As stated in the Report (at page 10), DEP asked Synapse to complete three tasks to analyze electricity demand during peak demand:

- project Connecticut electricity demand for the period from 2005 to 2020;
- project generation and transmission from load; and
- project emissions and prepare a report that will be used as part of Connecticut's SIP to demonstrate attainment with the federal eight-hour ozone standard.

On behalf of its operating companies in Connecticut,[1] NRG Energy, Inc. ("NRG") hereby submits its comments on the Report. NRG's comments focus on the following issues:

1. the cost recovery method for the installation of controls on units that are covered by a Reliability Must Run contract ("RMR units"),
2. the Report's use of year 2005 operations as the baseline for its projections;
3. the omission of new planned generation in the state;
4. the omission of potential controls on combustion turbines as a means for HEDD reductions;
5. the need for a CO2 adder;
6. the limited options presented by the Report to meet the HEDD commitment; and
7. the use of the 12 highest demand days to determine HEDD emissions.

Cost Recovery Method for Installation of Controls on RMR Units

The Report states (at page 4) that:

> [i]nstalling controls on affected sources also will add costs. These costs will be passed along to Connecticut ratepayers through existing cost recovery mechanisms available through the CT Department of Public Utility Control (DPUC), and through higher hourly clearing prices in the [ISO New England Inc.] electricity market.

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[1] NRG's Connecticut companies are Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC and Norwalk Power LLC.

For RMR units, a cost recovery mechanism may not be available. Under the RMR contracts for NRG's Middletown Station ("MD"), Montville Station ("MV"), and Norwalk Harbor Station ("NH") the MD, MV, and NH units' contracts are scheduled to expire upon the start of the Forward Capacity Market ("FCM") in June 2010. On these dates, the MD and MV NRG units at must recover their costs solely through the energy and capacity markets or in the case of NH, under terms determined to be just and reasonable by the FERC until June 2011. An HEDD program that mandates reductions from the present RMR units must take into account that the owners of such generation will have to give serious consideration as to whether project economics can support additional investment for environmental compliance. All options including plant shutdown and unit de-rates will have to be considered as alternatives to continued operation. The Department should not assume that there is full recovery of HEDD costs through the market or other contractual means.

The Report's Use of Year 2005 Operations as a Baseline for Projections

The Report uses year 2005 operations as the baseline for its projections. Using a one year period as the basis for projecting future demand, generating unit operations or NOx emissions may yield non-representative results. At a minimum, a one-year period may not properly capture fuel price volatility or unusual weather variations. Both fuel price volatility and weather conditions can alter both demand and the resulting generating levels for each generating unit. For these reasons, NRG asserts that a three year period should be used as the baseline for the Report's projections

Synapse partially recognized these potential issues when reviewing the year 2005 data and excluded from the analysis two data sets. Demand and generating information for the "cold snap" period of January 18 – 30, 2005 were excluded because the lack of natural gas for generation altered the generation mix normally expected. Second, the Report omitted periods when the congestion charge for southwest Connecticut ("SWCT") exceeded $20. The Report concluded that, at this congestion level, units within SWCT were dispatched even if they were not economic and, given the transmission upgrades currently being completed, this level of congestion is unlikely to continue in the future.

However, even with the exclusion of this data, the year 2005 operating, demand and NOx emissions data are not good indicators for the projections that would result from the analysis.

A. Projecting Future Operations

In particular, year 2005 generating units' operations are not a good basis to predict future operations for several reasons. NRG has collated the individual unit generation for the five year period of 2003 – 2007 for each of the NRG-owned generating boilers. Depicted in Figure 1, the data clearly shows a spike in year 2005 generation. (The generating data are presented in tabular form in Table 1.) NRG does not have access to the operating records for the units not owned by NRG, but the data suggests that circumstances likely caused a spike, not only in NRG's generation, but also perhaps in others' generation. Conversely, some generating units potentially experienced lower than expected operations for the same year.

In 2005, oil and natural gas prices varied throughout the year. The period following Hurricanes Katrina and Rita saw abnormal spikes in gas prices, which, in turn, caused a usually high level of oil usage during a period when natural gas is typically the less expensive fuel. The NRG-owned generating units are either oil-fired or dual fuel (gas and oil) fired. Hence, their ability to fire oil during high gas price periods could explain some of the spike in their generation. On the other hand, units fired solely by gas likely experienced lower than normal operations.

Additionally, specific to NRG's generating units, in Spring 2005 the cable that connects the AES Thames plant ("AES")[2] to the transmission system experienced problems that continued through mid-Fall 2005. NRG believes that one reason for the sharp increase in generation at MV during 2005 was due partly to the issue associated with the AES transmission cable.

B. Projecting NOx Emissions

The Report also uses the NOx emissions data from 2005 to project future emissions levels. However, year 2005 emissions data is not an accurate reflection of the current NOx emission rate from three of NRG's units: MD Unit 2 ("MD2") and Norwalk Harbor Units 1 and 2 ("NH1&2"). The Report concentrates on NOx reductions that are possible from units with an RMR contract. The RMR units noted in the Report amount to approximately 1,900 MW of installed capacity. MD2 and NH1&2 are about 465 MW of this capacity. To over-estimate the NOx emissions from 25% of the capacity covered by the Report will overestimate projected NOx emissions.

During the Summer of 2007, NRG added a high energy reagent technology ("HERT") system for the control of NOx emissions to MD2.[3] MD2 has been operated on a limited basis since the HERT system became operational, but, based on this limited operation, NRG expects the NOx rate to be no greater than 0.14 lb/MMBTU across the load range, which is lower than the NOx rate for MD2 in year 2005 assumed as the basis from Synapse's projections.

Additionally, throughout 2005 NRG experienced operational issues associated with the selective non-catalytic reduction ("SNCR") system for NH1&2. NH1&2 are each approximately 165 MW oil fired units. The SNCR issue was associated with the hardness of the water used in the urea system. This caused injector plugging, resulting in a NOx rate higher than expected but in compliance with the regulatory daily NOx rate limit. The issue was resolved in early 2006, and the NOx rate for NH1&2 is now lower than in year 2005 across the load range.

<u>Omission of New Planned Generation in Connecticut</u>

Section 3 of the Report includes the tasks and assumptions that were used in the analysis. The assumptions include the load growth, future energy efficiency programs in the state, the elimination of congestion in southwest Connecticut due to the completion of new transmission lines, nuclear unit operations, and the energy efficiency load shape.

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2 AES is a base loaded coal plant, rated at approximately 200 MW. This plant is located less than ¼ mile from MV and is interconnected to the same transmission line as MV.

3 MD2 is a dual fuel-fired 120 MW unit.

The Report makes the assumption that, once future demand is determined, if demand is greater than available generation, then the demand will be met with new gas-fired generation. While this may be true, the Report omits from its analysis planned new generation within the state. Approximately 1,460 MW of new generation is planned for the state within the next five years, pursuant to two, separate procurement proceedings conducted by the DPUC. [4] The addition of such a large amount of generation will affect future operations of all existing resources, and therefore their NOx emissions. Given the substantial addition of new generation, operation of the existing generation at full load conditions on all HEDD events is highly unlikely. Accordingly, the Report's analysis should incorporate the projected commercial in-service dates for all of the new generation and estimate the resulting NOx emissions on the HEDD events.

Omission of Potential Controls on Combustion Turbines

The Report concentrates on RMR units and ignores potential NOx emission reductions by non-RMR units during HEDD events,[5] concluding that:

> Connecticut DEP can meet the OTC MOU commitment to reduce NOx emissions through a combination of reducing emissions from the RMR units and continuing to have sustained performance from the state's energy efficiency programs. Achieving the second phase, with NOx emissions decreasing a total of 50% from 2005 levels, will require additional reductions from the RMR units and ramping up energy efficiency programs to levels higher than 2008 in order to achieve these levels by 2020.

However, where technically and economically feasible, the addition of water injection to the older combustion turbines ("CTs") also provides an effective means to lower HEDD NOx emissions.

On April 16, 2008, the Department issued an analysis of an alternate baseline for the HEDD emissions, based on data from 20 CTs on three days, July 27, 2005 and August 1 and 2, 2006. The analysis assumed a 40% reduction in NOx emissions from the older CTs in the state, and showed elimination of between two and six tons per day of NOx emissions based on this level of reduction.

Recently, NRG installed water injection on three existing CTs at its Cos Cob site. The pre-controlled NOx rate was 0.8 lb/MMBTU (the Full Load Emission Rate listed in the NOx Trading Order). While NRG has not completed the stack testing of the units, NRG expects that the

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4 Under the Energy Independence Act, the DPUC selected four projects for development for a total of 787 MW of incremental capacity will be added to the grid, with 782 MW being from three generating resources: 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 currently operational while the other two generating facilities will be operational no later than 2011. The final five MW will be procured from statewide energy efficiency projects. Additionally, the DPUC recently selected 678 MW of peaking generation, comprised of three projects proposed for construction within the state: 360 MW at site in Bridgeport with an in-service date of December 2010, 194 MW at a site in Milford with an in-service date of June 2010, and 130 MW at a site in New Haven with an in-service date of June 2012.

5 The non-RMR units include Bridgeport Harbor Units 2 and 4, as well as the statewide fleet of older combustion turbines.

controlled NOx rate will be approximately 0.22 lb/MMBTU, or equal to a 70% reduction in the NOx rate.

Clearly, the installation of the water injection system at Cos Cob provides an effective means to achieve part of the HEDD commitment. However, the Report does not assume controls on these units, with perhaps the exception of Middletown Unit 10 and Norwalk Harbor Unit 10 ("NH10"), which are listed in the Report as RMR units[6]. The assumption that NOx controls can be added to NH10 has not been technically proven.

<u>Need for a CO2 Adder</u>

The Report does not indicate whether Synapse included a CO2 allowance cost "adder" to a generating unit's dispatch price in arriving at its prediction of future operations. With the scheduled implementation in the state of the Regional Greenhouse Gas Initiative ("RGGI") on January 1, 2009, generating resources will be required to obtain CO2 allowances equal to their CO2 emissions. The majority of the allowances will be auctioned and, therefore, the resources will incur an additional operating cost. All generating resources affected by RGGI are expected to include the cost of the allowances in their dispatch price bids.

The CO2 emissions rates of oil-fired units differs from natural gas fired units, with the natural gas fired units' emissions rates being about 30% lower. Depending on the predicted cost of a RGGI allowance, the use of natural gas firing may increase, because the cost of CO2 emissions may be high enough to make a natural gas-fired unit more economical than an oil-fired unit. Moreover, a shift to a higher percent of gas firing over oil firing will lower NOx emissions, because the NOx rate from the generating units is lower when firing gas than when firing oil. Accordingly, the Report should reflect the cost of RGGI CO2 allowances and analyze what impact implementation of RGGI will have on NOx emissions.

<u>Limited Options to Meet HEDD Commitment</u>

The Memorandum of Understanding ("MOU") on the HEDD commitment states that "each state shall select the strategy or combination of strategies that provides both maximum certainty and appropriate flexibility for that state and its electric generators." Yet the Report's conclusion focuses on only two strategies as the means to reduce NOx emissions on HEDDs: an increase in energy efficiency programs and lowering NOx emissions from RMR units.[7]

Other compliance methods that may be employed and that are listed in the MOU, include state/generator HEDD partnership agreements, demand response programs (provided that such programs reduce or preclude the installation or use of distributed generation with unacceptable high emissions), regulatory standards or controls for behind-the-meter generators, and effective adjustment of the NOx retirement ratio to provide reductions on HEDD. These other compliance methods should not be ignored when the DEP issues its draft regulations for the HEDD program. All of them provide the means to meet the HEDD commitment and, therefore, their inclusion as

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6 It should be noted that Norwalk Harbor Unit 10 is not an RMR unit.

7 The Report states that, at the operator's discretion, RMR units could install controls or reduce the full load output from the unit in order to reduce NOx emissions.

compliance options provides generators with maximum flexibility to achieving reductions at the lowest cost. In addition, the Department must also look to the non-RMR units to provide NOx emission reductions, because their emissions were included in the analysis establishing the Baseline HEDD NOx emissions under the MOU.

NRG disagrees with the Report's position on the use of a NOx retirement ratio, namely that "if such a program was implemented anyway, even a few high electric demand days would require surrender of a large portion of Connecticut's emissions budget, leaving little for the remaining days. This would likely lead to temporarily shutting down fossil fuel generation for many days if not weeks, and electricity would have to be imported from elsewhere, at higher costs, into Connecticut."[8] This conclusion appears to be based on a HEDD program where only NOx allowances allocated to a Connecticut site could be used as a means of compliance under the HEDD program. The NOx allowances that could be used are those allocated under the Clean Air Interstate Rule ("CAIR"). Twenty-eight states are covered by CAIR, of which only three are not part of the Ozone Season NOx program. Since CAIR is a regional cap-and-trade program to aid in the attainment of the Ozone standard, it only stands to reason that the use of CAIR NOx allowances independent of the state of origin should be allowed as a compliance option in a HEDD program. The Report's conclusion on the use of CAIR allowances should be re-evaluated based on the entire universe of CAIR allowances.

Use of 12 Highest Demand Days to Determine HEDD Emissions

It is unclear why the Report uses the 12 highest demand days as part of the basis for its analysis. NRG disagrees that the single day listed in the MOU -- July 26, 2005 -- should be used as the baseline day to determine the baseline HEDD emissions. NRG has demonstrated in previous submittals to the Department that the use of a three-day average is the more appropriate method than the single day for determining the baseline emissions.

Using the analysis in the Report, rather than a single day or even the NRG proposed three-day average, yields different results regarding the need for a HEDD program, at least for the NRG units. As shown in Table 2 below, operations of the NRG units exceeded the proposed HEDD cap for these units on only four of the 12 highest demand days in year 2005. The HEDD cap for the NRG units was calculated using the ratio of the NOx emissions from the NRG units to the NOx emissions for all HEDD units included in the NOx analysis for July 26, 2005. The 25% reduction in the baseline emissions relates to an overall HEDD "cap" of 29.25 tons per day for the NRG HEDD units (or a 9.7 ton per day reduction).

In fact, the 12-day average NOx emissions from the NRG units are 27.12 tons per day, which is below the HEDD cap. This suggests either that a HEDD program is not needed or that other units, rather than the NRG RMR units, must reduce their NOx emissions.

If the Department elects to use the 12 highest days to determine the HEDD baseline, then the committed tons per day of 11.7 tons must be recalculated based on the committed 25% reduction in the MOU. This in turn, will reduce the daily NOx commitment for individual units or companies covered by the HEDD program.

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8 See page 9 of the Report

Conclusion

The Report presents a good starting point to develop a HEDD program in Connecticut. However, in its current form, the Report should not be used as the basis for the HEDD program. The Report's analysis should be modified as follows:

1. include the new planned generation within the state;
2. use a three-year average for demand, generation and NOx emission rates as the basis for projections rather than relying only on year 2005 data;
3. consider the NOx reductions that could be achieved from the installation of controls on non-RMR units; and
4. incorporate a CO2 allowance adder to reflect the costs of implementation of RGGI within the state.

TABLE 1
YEARS 2003 – 2007 GROSS GENERATION DATA
NRG STEAM ELECTRIC BOILERS

Year	Middletown 2	Middletown 3	Middletown 4	Montville 5	Montville 6	Norwalk 1	Norwalk 2
2003	60,250	335,896	74,104	48,592	209,636	151,344	159,349
2004	207,818	198,791	81,965	34,527	130,504	145,322	197,871
2005	**331,505**	**377,153**	**272,120**	**139,111**	**431,873**	**242,535**	**358,188**
2006	163,347	253,447	120,386	36,523	131,906	165,307	230,534
2007	177,175	270,197	75,135	41,746	60,478	126,524	187,294

Notes:
1. Data are gross megawatt-hours (MWh) for each unit for each year.
2. Middletown 2 is a 120 MW natural gas and No. 6 oil fired unit
3. Middletown 3 is a 235 MW natural gas and No. 6 oil fired unit
4. Middletown 4 is a 400 MW No. 6 oil fired unit
5. Montville 5 is an 80 MW natural gas and No. 6 oil fired unit
6. Montville 6 is a 400 MW No. 6 oil fired unit
7. Norwalk 1 is a 170 MW No. 6 oil fired unit
8. Norwalk 2 is a 170 MW No. 6 oil fired unit

TABLE 2
NRG HEDD UNITS HISTORIC EMISSIONS
12 HIGHEST DEMAND DAYS IN 2005

Date	MW Load	NOx tons	HEDD Limit	Delta
July 27	26,420	39.41	29.25	10.16
July 19	26,230	24.12	29.25	-5.13
August 5	25,400	29.93	29.25	0.68
July 26	25,020	38.22	29.25	8.97
August 11	24,760	30.94	29.25	1.69
July 20	24,540	17.54	29.25	-11.71
July 22	24,440	26,55	29.25	-2.7
August 10	24,240	24.74	29.25	-4.51
August 3	24,040	27.85	29.25	-1.4
August 8	23,950	25.29	29.25	-3.96
June 27	23,940	16.23	29.25	-13.02
August 4	23,900	24.76	29.25	-4.49
Average	24,740	27.13	29.25	-2.12

Notes:

1. Baseline NRG tons are 39 tons
2. HEDD limit is 25% reduction from baseline or 29.95 tons
3. Data do not include emissions from Devon Units 11 – 14 because they have water injection for the control of NOx.
4. Data do not contain Montville Units 10 and 11 because they were not considered HEDD units in the MOU.

FIGURE 1
2003 - 2005 Yearly MWh
NRG Steam Electric Units