New Hampshire Regional Haze SIP Revision
Responses to Federal Land Managers' Comments

On June 26, 2009, the New Hampshire Department of Environmental Services (NHDES) received written comments on New Hampshire's draft final Regional Haze SIP, May 22, 2009, from the U.S. Department of the Interior, National Park Service (NPS). These comments specifically addressed the Best Available Retrofit Technology (BART) provisions of New Hampshire's regional haze plan. The following are NHDES's responses to NPS's comments. **Comments are reproduced in *italics* and responses appear in regular font.**

PSNH Merrimack Station Unit MK2

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2, the only BART-eligible unit, is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 mmBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction (SCR) to remove oxides of nitrogen (NOx) formed during the combustion process. Two electrostatic precipitators (ESPs) operate in series to capture particulate matter (PM). Also, construction has begun on a scrubber system that will reduce sulfur dioxide (SO_2 emissions. According to EPA Clean Air Markets (CAM) database, in 2007, emissions from Unit #2 were: 25,064 tpy SO_2 (@ 1.97 lb/mmBtu) and 2,248 tpy NOx (0.19 lb/mmBtu).

Retrofit options for this unit are limited because the facility already has controls in place for NOx and PM, and only a few emission control technologies are compatible with the type of boiler design employed.

BART Analysis for SO_2

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: SO_2 control technologies available and potentially applicable to Unit MK2 are wet flue gas desulfurization (FGD) and use of low-sulfur coal.

NPS: PSNH has proposed wet FGD which potentially provides the highest level of reduction.

STEP 2 – Eliminate technically infeasible options

NPS: No SO_2 control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent (NESCAUM, 2005).

NPS: NHDES should include requirements that PSNH optimize operation of the wet FGD.

- NHDES Response: In order to meet the conditions set by state law, the wet FGD is currently being optimized for mercury emission reductions. It is unreasonable to require state-of-the-art performance for SO_2 removal as if it were the only pollutant of interest. However, after undertaking the large financial commitment necessary to construct and operate the FGD system, PSNH has a vested interest in reducing

emissions of both pollutants to the maximum practicable extent. There is little advantage to be gained by PSNH in accepting less than optimum performance of this system because doing so could create other operational problems.

The Temporary Permit for this facility (Attachment EE of Regional Haze SIP) includes provisions that will reset the required SO_2 percent reduction to the maximum sustainable rate with the new FGD system after an initial operating period. The specific language of the permit is as follows: "The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation, excluding the initial startup and commissioning period and any periods when the FGD system is not operating…DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES…This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent."

Also, it should be noted that PSNH has worked to control the sulfur content of the coal in order to reduce SO_2 emissions. Because the particular boiler design does not permit the burning of straight low-sulfur coal, the company blends coals to bring average sulfur content to a level that is consistent with sustainable boiler operations.

STEP 4 – Impact analysis

NHDES: Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MKI and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost equates to about $1,400 per ton of SO_2 removed.

NPS: The estimated cost is within the range of reasonable costs suggested by EPA.

STEP 5 – Determine visibility impacts

see below

Determination of BART for SO_2

NHDES: New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both MK1 and MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (applicable to EGUs substantially larger than Merrimack Station), the FGD system is considered to be BART for SO_2 on Unit MK2. NHDES is not requesting further action of Merrimack station at this time in order to comply with BART.

NPS: NHDES should include requirements that PSNH optimize operation of the wet FGD.

- ▶ NHDES Response: Please see previous response.

BART Analysis for NOx

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: The only NOx control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction (SNCR) and SCR.

NPS: PSNH has proposed SCR which potentially provides the highest level of reduction.

STEP 2 – Eliminate technically infeasible options

NPS: No NOx control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: NOx emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers in the U.S. In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired wet-bottom cyclone boiler in the U.S. Designed to meet NOx Reasonably Available Control Technology (RACT) limits, the SCR has reduced NOx emissions by 85 to 92 percent. Unit MK2 is also required to meet a federal acid rain limit of 0.86 lb NOx/mmBtu, an additional NOx RACT Order limit of 15.4 tons per calendar day, and a NOx RACT Order limit of 29.1 tons per calendar day for Units MK and MK2 combined. PSNH is allowed to meet the 15.4 ton-per-day limit for Unit MK2 by using ozone-season discrete emission reductions (DERs). In 2002, actual NOx emissions for Unit MK2 were reported as 2,871 tons.

NPS: NHDES should explain why the SCR (with or without addition of combustion controls) cannot achieve better than the estimated 85 percent control. NHDES should include requirements that PSNH optimize operation of the SCR.

- ▶ NHDES Response: Since January 2001, the SCR on Unit MK2 has reduced NOx emissions to between 0.15 and 0.37 lb/MMBtu (calendar monthly average), with a few excursions outside this range. (Note that the existing NOx RACT limit of 15.4 tons per calendar day is mathematically equivalent to 0.37 lb/MMBtu.) Data available from the period of 1993 to early 1995, prior to operation of the SCR, provide a baseline for uncontrolled NOx emissions in the range of 2.0 to 2.5 lb/MMBtu. Taken together, this information indicates that Unit MK2 achieves a control level greater than 85 percent most of the time. PSNH may also have a monetary incentive to surpass the NOx RACT requirement because further emission reductions allow the utility to accumulate DERs. With respect to optimization, Unit MK2 has an early-generation SCR that previously received retrofits to improve its performance. Additional upgrades would require major redesign and construction at a location where physical space is already constrained. Capital costs would be comparable to installing a new SCR and would achieve only marginal additional reductions in NOx emissions.

STEP 4 – Impact analysis

NHDES: Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about $400/ton for year-round operation and about $600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to $530/ton and

$790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NOx RACT requirements. Year-round operation is EPA's presumptive norm for BART (applicable to EGUs of 750 MW capacity or greater) for units that already have seasonally operated SCRs. Assuming that operating costs are proportional to operating time, the difference in cost between year-round and seasonal SCR operation for Unit MK2 is about $3,300,000, based on PSNH's 1998 cost estimates. The cost differential could be about half that amount, if based on the current (but more generic) estimates presented in Table 2-1.

NPS: The estimated cost is within the range of reasonable costs suggested by EPA.

STEP 5 – Determine visibility impacts

see below

Determination of BART for NOx

NHDES: Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. The estimated costs of NOx emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1 of the BART report. These estimates are based on assumptions used in EPA Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an EGU the size of Unit MK2. Because the SCR system is already in place to meet other air program requirements and can be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NOx control on Unit MK2.

NPS: Because the only federally-enforceable NOx limit (described above) does not reflect the full capability of SCR and is well above the presumptive 0.10 lb/mmBtu BART limit for a cyclone furnace, NHDES should include limits that reflect the full capability of the NOx reduction system.

- ▶ NHDES Response: The presumptive BART limit is generally applicable to power plants having greater than 750 MW capacity and may not be representative of smaller EGUs like Unit MK2. In the case of Unit MK2, the cyclone boiler has a relatively high uncontrolled NOx emission rate (≥2.0 lb/MMBtu), so it follows that the controlled emission rate, even at 90 percent control efficiency, would be above the presumptive norm applicable to larger facilities. As seen in the past decade of emissions records for Unit MK2, monthly average NOx emissions have normally ranged between 50 and 100 percent of the RACT limit. The existing NOx RACT limit of 15.4 ton/day, equivalent to of 0.37 lb/MMBtu, corresponds to a NOx control rate of about 85 percent. NHDES finds that a NO_X emission rate of 0.30 lb/MMBtu reasonably and cost-effectively represents the sustainable performance capabilities of this unit and is also appropriate as a BART control level for NO_X on a 30-day rolling average basis.

BART Analysis for PM

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: The only PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

NPS: NHDES should have considered simple, inexpensive upgrades for the ESPs to achieve

greater control.

STEP 2 – Eliminate technically infeasible options

NPS: No PM control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK.2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/mmBtu and a TSP emissions cap of 3,458.6 tons/year. Actual TSP emissions from this unit were 210 tons in 2002.

NPS: A properly designed and operated ESP should be able to achieve 0.015 lb filterable PM/mmBtu. In fact, the data presented by NHDES indicates that the ESPs achieved 0.019 lb TSP/mmBtu in 2002 based upon CAM data heat input of 22,013,515 mmBtu in 2002.

- NHDES Response: The 0.227 lb/MMBtu limit derives from the formula established in Env-A 2002.06 and does not reflect the true capabilities of the ESPs serving Unit MK2 to control particulate emissions. Stack testing on three separate dates in 1999 and 2000 found actual TSP emissions to be 0.043, 0.041, and 0.021 lb/MMBtu after controls. The most recent test, in May 2009, produced an emission rate of 0.032 lb/MMBtu.

STEP 4 – Impact analysis

NHDES: Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $2.6 million to $8.3 million, or $90 to $280 per ton of PM removed…

NPS: NHDES conducted no analysis of the cost of upgrading the ESPs.

- NHDES Response: The existing ESPs were previously upgraded to include state-of-the-art electronic controls. Further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of severe spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of $10,000 to $30,000 per MW. For Unit MK2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.01 dv on the 20 percent worst visibility days) that would be realized.

Determination of BART for PM

NHDES: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress. The existing ESPs, operating in conjunction with the FGD

process, will provide the most cost-effective controls for particulate emissions. Therefore, continued operation of the existing ESPs is considered to be BART for PM control on Unit MK2.

NPS: Although the existing ESPs may well represent BART, NHDES should evaluate possible upgrades, or, at least, establish a federally-enforceable permit limit that reflects the actual capabilities of the units.

- ▶ NHDES Response: Despite the existence of former stack test results, the volume of data is deemed insufficient to establish a conclusive, long-term BART performance level of 0.04 lb/MMBtu or lower for this unit. Accordingly, NHDES has developed a draft rule that will hold TSP emissions to no greater than 0.08 lb/MMBtu, but on a broader scope than required under BART: this standard will apply to Unit MK1 (not a BART-eligible facility) and Unit MK2. In the current draft Title V operating permit, Unit MK1 has a TSP emission limit of 0.27 lb/MMBtu, or more than three times the proposed limit of 0.08 lb/MMBtu. By including Unit MK1 in the rule, the combined allowable TSP emissions from the two coal-fired units at Merrimack Station (377 lb/hr) will be reduced to less than the total allowable TSP emissions under a hypothetical scenario in which the limit for Unit MK2 would be revised to 0.04 lb/MMBtu and the limit for Unit MK1 would remain unchanged (473 lb/hr).

STEP 5 – Determine visibility impacts

NHDES: The NHDES conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas such as Acadia National Park, Moosehorn National Wildlife Refuge, and Lye Brook Wilderness Area (i.e., concentration impacts were converted to visibility impacts). For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

NPS: EPA recommends use of CALPUFF for modeling single sources in situations like this. CALGRID is more appropriate for multi-source regional modeling and under- predicts impacts relative to CALPUFF. It is likely that, had NHDES applied CALPUFF, it would have produced results that predict significantly higher estimates of visibility benefits that would result from the proposed emission controls.

- ▶ NHDES Response: According to EPA guidance, CALPUFF or other EPA-approved model may be used to estimate the magnitude of a source's impacts on visibility after implementation of various BART control levels. NHDES agrees with NPS that, if the CALPUFF model had originally been used to perform this assessment, then higher estimates of visibility improvement may have been predicted. CALPUFF is EPA's preferred model for performing long-range visibility assessments of individual sources to distant Class I areas, in part because it is considered to be a conservative model or one that is capable of estimating worst-case impacts rather than expected impacts. This makes CALPUFF ideally suited to screening BART sources for exemption purposes because it is likely to identify virtually all sources

that could provide visibility benefits when their emissions are controlled.

CALGRID is a sister program to CALPUFF and shares much of the same chemistry; however, it works as a gridded model rather than a puff tracking model, and it has the advantage of easily tracking 20% worst visibility days and cumulative impacts by modeling all source sectors. NHDES chose to use CALGRID since it is much easier to track the dynamics of impacts from single sources to multiple Class I areas on targeted days, rather than just applying the maximum impact conditions that may or may not be associated with 20% worst days. While the CALPUFF model's CALPOST post-processor has an option for application on 20% best visibility days, it does not in fact isolate those 20% best days for analysis. It simply changes the background values the model uses to adjust what it estimates to be appropriate background levels. It does not account for wind directions that may be preferentially included or excluded on such days.

Nevertheless, to provide a comparison with New Hampshire's CALGRID modeling results, NHDES conducted a limited set of CALPUFF runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions.

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit MK2 produce theoretical CALPUFF worst-case impacts of 2.29 dv at Acadia National Park. EPA considers acceptable source exemptions when this form of conservative modeling indicates a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit MK2 exceed all of these exemption levels.

The BART assessment modeling provides a comparison of visibility impacts from current allowable emissions with those from the post-control emission level (or levels) being assessed. Results are tabulated for the average of the 20% worst visibility (in this case, about 22.8 dv) modeled days at each nearby Class 1 area. For any pair of control levels evaluated, the difference in the level of impairment predicted is the degree of improvement in visibility expected.

Rather than use CALPOST to manually manipulate background deciview calculations, NHDES normalized CALPUFF modeling results and then applied predicted concentrations to a logarithmic best-fit equation to the actual observed $PM_{2.5}$-to-deciview relationship measured at Acadia NP, Great Gulf NW, and Lye Brook NW. Thus, as recommended by BART modeling guidance, CALPUFF was applied in a relative way using real observed data as the basis. At this point, a number of background visibility scenarios could be calculated from the resulting PM-mass-to-deciview equation. According to BART guidance, the natural visibility condition (about 7 dv) was used for exemption purposes, and 20% worst visibility (22.8 dv) was used for assessment of BART control effectiveness. The CALPUFF-predicted visibility benefits from BART controls on 20% worst visibility days are as

follows:

CALPUFF Modeling Results for Merrimack Station Unit MK2:
Visibility Improvements from BART Controls on the 20% Worst Visibility Days

Pollutant	Control Technology	Control Level	Visibility Improvement (dv)		
			Acadia NP	Great Gulf NW	Lye Brook NW
SO_2	FGD	90%	0.28	0.22	0.03
NO_X	SCR Upgrade	89%	0.01	0.01	< 0.01*
PM	ESP Upgrade	99.4%	<0.01*	<0.01*	< 0.01*
	Baghouse	99%	-0.02	-0.02	-0.01

* below sensitivity limit of model

While Unit MK2 was predicted to have up to 2.29 dv impact at Acadia National Park under natural conditions, the basis of the BART assessment evaluation changes to 20% worst visibility days. On those days, a 90% reduction in sulfur emissions at Unit MK2 results in only a 0.28 dv visibility improvement. At first these results may appear to be incorrect; however, on further examination, it is found that CALPUFF predicts the same amount of sulfate from Unit MK2 reaching Acadia under both best and worst visibility conditions. The difference is that there is greater than an order of magnitude more sulfate coming from other sources on the 20% worst visibility days, raising the background concentrations to much higher levels. Because the deciview scale is logarithmic, the same mass reduction of 0.26 $\mu g/m^3$ of sulfate from this one source results in wide differences in deciview impacts for different background visibility conditions at opposite ends of the range.

The above analysis indicates that CALPUFF and CALGRID have aligned better in their predictions than might be expected. This result may be attributed to the similar chemistry used in both models and to the specific circumstances of this case in which the prevailing wind direction on the 20% worst visibility days carries Unit MK2 emissions directly toward Acadia National Park. The big discrepancy occurs under best visibility days, when CALGRID (correctly) does not align the source to receptor, but CALPUFF (incorrectly) applies wind directions for worst visibility days to the best day calculations.

PSNH Newington Station Unit NT1

Unit NT1 is the sole electrical generating unit at PSNH Newington Station. It operates at irregular times, principally during periods of peak electric demand. Power is derived from an oil- and/or natural-gas-fired steam-generating boiler with a heat input rating of 4,350 mmBtu/hr and an electrical output of 400 MW. Installed in 1968, the boiler is equipped with low-NOx burners, an overfire air system, and water injection to minimize the formation of oxides of nitrogen (NOx) during the combustion process. The facility also has an electrostatic precipitator to capture particulate matter (PM) in the flue gases. Partial control of SO_2 emissions is provided by sulfur content limits on the fuel oil. According to EPA's Clean Air Markets (CAM) database, in 2002, which were the basis of the New Hampshire Department of

Environmental Services (NHDES) BART analysis, emissions from Unit #1 were: 5,226 tpy SO_2 (1.08 lb/mmBtu) and 943 tpy NOx (@ 0.18 lb/mmBtu).[1]

BART Analysis for SO_2

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: SO_2 control technologies available and potentially applicable to Unit NT1 are wet flue gas desulfurization (FGD) and use of low-sulfur oil.

NPS: NHDES identified a reasonable suite of options.

STEP 2 – Eliminate technically infeasible options

NPS: No SO_2 control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent (NESCAUM, 2005).

NPS: NHDES should explain what control efficiency is assumed for the hypothetical new scrubber.

- NHDES Response: For FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions. Newington Station Unit NT1 is a considerably smaller (400 MW), oil-fired unit; and there is only limited experience with FGD systems on oil-fired EGUs. However, it may be assumed that a hypothetical new scrubber system for Newington Station would perform at a similar level, achieving SO_2 removal efficiencies of 90 percent or greater.

STEP 4 – Impact analysis

NHDES: Despite expressing concern about the high cost estimates,[2] *NHDES used the latest Merrimack Station estimate of $l,055/kW for scaling purposes to estimate that the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. NHDES states that "Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about twice the cost of FGD on coal-fired boilers of comparable size (NESCAUM, 2005)." NHDES did not estimate annual costs or cost-effectiveness for this option.*

NPS: According to NHDES, "The costs of fuel switching at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur fuel at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual

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[1] *According to the CAM database, in 2007, emissions from Unit #1 were: 2,269 tpy SO_2 (@ 1.05 lb/mmBtu) and 415 tpy NOx (@ 0.16 lb/mmBtu).*

[2] *However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE- VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the recent estimate of $300 to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?,"* Power, *March 1, 2009).*

fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately $3.3 million per year, or $1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately $6.6 million per year, or also $1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2008 has been below 2002 levels). These results imply that the cost of fuel switching may be relatively constant on a $/ton basis as long as supplies are adequate...Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended."

STEP 5 – Determine visibility impacts

NHDES: The NHDES conducted a screening level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit NT1. The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas such as Acadia National Park, Moosehorn National Wildlife Refuge, and Lye Brook Wilderness Area (i.e., concentration impacts were converted to visibility impacts). For the affected Class I areas, reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a negligible improvement in visibility, according to NHDES.

NPS: EPA recommends use of CALPUFF for modeling single sources in situations like this. CALGRID is more appropriate for multi-source regional modeling and under-predicts impacts relative to CALPUFF. It is likely that, had NHDES applied CALPUFF, it would have produced results that predict significantly higher estimates of visibility benefits that would result from the proposed emission controls.

- NHDES Response: The same methodologies used for the CALPUFF modeling work for Merrimack Station Unit MK2 were applied to Newington Station Unit NT1.

  The BART eligibility modeling conducted by MANE-VU used natural visibility conditions (about 7 dv) to produce the most conservative modeling results to minimize sources from modeling out of BART. Under these conditions, uncontrolled emissions from Unit NT1 produce theoretical CALPUFF worst-case impacts of 1.22 dv at Acadia National Park. EPA considers acceptable source exemptions when this form of conservative modeling indicates a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, a more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit NT1 exceed all of these exemption levels. The CALPUFF-predicted visibility benefits from BART controls on 20% worst visibility days are as follows:

CALPUFF Modeling Results for Newington Station Unit NT1:
Visibility Improvements from BART Controls on the 20% Worst Visibility Days

Pollutant	Control Technology	Control Level	Visibility Improvement (dv)		
			Acadia NP	Great Gulf NW	Lye Brook NW
SO_2	1% S Fuel Oil	50%*	0.08	0.06	< 0.01**
	0.5% S Fuel Oil	75%*	0.12	0.09	0.01
	0.50 lb SO_2/MMBtu	77%*	0.12	0.09	0.01
	0.3% S Fuel Oil	85%*	0.13	0.10	0.01
	FGD	90%*	0.14	0.11	0.02
NOx	LNB	40%	< 0.01**	< 0.01**	< 0.01**
	LNB-OFA	50%	0.01	< 0.01**	< 0.01**
	SNCR	50%	0.01	< 0.01**	< 0.01**
	SCR	85%	0.03	0.02	< 0.01**
PM	Baghouse	99%	<0.01**	<0.01**	< 0.01**

* from maximum permitted level ** below sensitivity limit of model

Determination of BART for SO_2

NHDES: Flue gas desulfurization is a potential SO_2 control option for PSNH Newington Station Unit NT1. However, the cost per ton for FGD on oil-fired boilers is estimated to be about twice the cost of this technology on coal-fired boilers and could be well in excess of $1,000/kW for Newington Station. Given the high costs of this option, it is apparent that FGD would he uneconomical as a retrofit for a peak-demand plant the size of Unit NT1.

Use of a lower-sulfur fuel is a practical option for controlling SO_2 emissions at Newington Station. When natural gas is available at reasonable cost relative to residual fuel oil, natural gas is the preferred fuel because of its very low sulfur content. Otherwise, use of low-sulfur residual fuel oil is a reasonable option. For relatively minor increases in the cost of fuel, switching to 1.0%-S or 0.5%-S residual fuel oil provides significant reductions in fuel sulfur content with proportional reductions in SO_2 emissions.

When not firing on natural gas, Unit NT1 has burned 2.0%-sulfur residual fuel oil (actual average fuel sulfur content was 1.2% in 2002). It is estimated that switching to 1.0%-sulfur residual fuel oil would reduce SO_2 emissions by about one-third, and switching to 0.5%-sulfur residual fuel oil would cut SO_2 emissions by about two-thirds. At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008$), would be about $3.3 or $6.6 million (equivalent to $0.0047 or $0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

Fuel switching could be accomplished without capital outlay and would have predictable costs tied directly to fuel consumption and fuel price differentials. A major consideration is fuel availability. In recent years, there have been sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. The future price and availability of natural gas are difficult to discern. While regional and national supplies of 1.0%-sulfur

residual fuel oil appear to be adequate to meet current demand, the present and future availability of 0.5%-sulfur residual fuel oil, in particular, is uncertain and speculative.

After consideration of projected costs, ease of implementation, and fuel availability, it is determined that using 1.0%-sulfur (low-sulfur) residual fuel oil is currently the Best Available Retrofit Technology for PSNH Newington Station Unit NT1 when natural gas is not available at reasonable cost. The use of 0.5%-sulfur (ultra-low-sulfur) residual fuel oil remains a future possibility that should be re-evaluated within the next few years. A further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all fuel oils throughout the region by 2018.

NPS: NHDES concluded that a FGD system is too expensive. We agree with the NHDES approach that use of lower-sulfur fuels is BART for this EGU. And, we commend NHDES for its proposal to reduce the sulfur limit on the #6 residual oil to 1%. Although NHDES also concludes that the cost of switching to 0.5% sulfur fuel oil is also reasonable (@ $1,900/ton – the same as the cost to go to 1.0% sulfur oil – it has deferred proposing that this additional reduction be required at this time. NHDES suggests that "future availability of 0.5%-sulfur residual fuel oil, in particular, is uncertain and speculative" and that its use "should be re-evaluated within the next few years." To support this contention, NHDES should present information from fuel oil suppliers concerning the uncertain availability of 0.5% sulfur oil. Furthermore, NHDES should explain how and when it would re-evaluate that issue and implement a requirement for 0.5% sulfur oil if it found it to be sufficiently available.

We believe that, if 0.5% sulfur fuel oil is found by NHDES to be reasonably available in the future, a determination that BART is 0.5% sulfur would be consistent with, and enhance the goals of the Northeast states as discussed in the document: "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues" provided by NHDES as attachment AA. For example, the Executive Summary of that document states:

> *The analysis summarized in this White Paper supports the Northeast states' conclusion that significant reductions in SO_2, NOx, and PM emissions can he achieved by mandating lower sulfur heating oil. Importantly, these reductions can he achieved with an expected cost savings to the consumer. Adding the public health and environmental benefits associated with lower sulfur fuel increases the favorable cost-benefit ratio of a regional 500 pm [sic] sulfur heating fuel program.*

- <u>NHDES Response</u>: There is greater assurance today of the availability 0.5%-sulfur residual fuel oil than when the original BART determination was drafted. Maine, Massachusetts, New Jersey, and possibly other states within MANE-VU have already made commitments to require the use of 0.5%-sulfur residual fuel oil, thus ensuring the presence of a regional market for this commodity. In recognition of the dual-fuel capability of this unit, NHDES has prepared a draft rule that will reduce sulfur dioxide emissions by imposing an SO_2 emission limit of 0.50 lb/MMBtu for this facility regardless of fuel type. The rule would allow the facility the flexibility to burn natural gas and/or fuel oil in any feasible ratio, depending on market conditions. (The boiler for Unit NT1 has a physical limitation of about 50 maximum heat input from natural gas, with no corresponding limitation on fuel oil.)

  For the first regional haze progress report, to be submitted circa 2013, NHDES will review fuel usage, fuel supplies, fuel prices, and plant utilization/capacity factors to determine whether the fuel sulfur limitation described above is still appropriate as BART control for Unit NT1. Should the review indicate a different BART control level, the facility's Title V operating permit will be amended as necessary before its

expiration date of March 31, 2012, exactly fifteen months prior to the effective date of proposed BART control measures.

BART Analysis for NOx

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: NOx control technology options available and potentially applicable to Unit NT1 are combustion controls, selective non-catalytic reduction, and selective catalytic reduction.

NPS: NHDES identified a reasonable suite of options.

STEP 2 – Eliminate technically infeasible options

NPS: NOx control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: NOx emission reductions of about 75 to 90 percent have been obtained with selective catalytic reduction (SCR) on coal-fired boilers in the U.S.

NPS: NHDES should explain why the SCR cannot achieve better than the estimated 85 percent control.

- NHDES Response: A hypothetical SCR system retrofit for Newington Station Unit NT1 would be expected to achieve a NOx control rate of 85 to 90 percent or better.

STEP 4 – Impact analysis

NHDES: The estimated costs of NOx emission controls for SNCR and SCR at Newington Station Unit NT1 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an EGU the size of Unit NTI. For SNCR, the total annual cost is estimated to be about $730,000, or $1,030/ton of NOx removed. For an SCR system, the total annual cost is estimated to be $1,410,000 or $1,180/ton. Because Unit NT1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.[3]

NPS: When we applied different assumptions for SCR (e.g., 90% NOx control, 20-year life, 7% interest) we arrived at a slightly higher ($1,278) cost/ton. Furthermore, Newington's capacity utilization and emissions have dropped so much in recent years that it is doubtful that any major capital expenditures would be justified as long as that low utilization continues. For example, in 2007, CAM data show that heat input had declined to 4.3 trillion Btu, and that NOx emissions were 415 tons.

STEP 5 – Determine visibility impacts

(same as above for SO_2)

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[3] *Estimates are derived from USEPA, Documentation for EPA Base Case 2006 (V 3.0 Using the Integrated Planning Model, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and 70l million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 704 tons of NOx removed for SNCR and an estimated 1,196 tons of NOx removed for SCR.*

- ▶ NHDES Response: It is useful to consider NOx emission reductions in the context of other emission reductions – especially sulfur dioxide. MANE-VU determined that SO_2 was the target pollutant for maximizing visibility improvements. The modeling results posted above for Unit NT1 predict minimal visibility improvements for SO_2 reductions ranging from 50% to 85%. NOx, while also an important visibility impairing pollutant, is less hydrophilic and impairs visibility less effectively than a similar mass of SO_2; therefore, in comparable mass emission reductions of SO_2 and NOx, there would be less visibility benefit from the NOx reductions. Further, potential NOx emission reductions resulting from installation of SNCR/SCR at Newington Station would be in the order of 20 to 50%. Therefore, it is not surprising that CALPUFF predicts visibility improvements of only about 0.03 dv for SNCR/SCR at this facility.

Determination of BART for NOx

NHDES: For the reasons below, the existing controls, which include low-NOx burners, overfire air, and water injection, are determined to be BART for Newington Station Unit NT1:

- *Many of the NOx reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of low-NOx burners and overfire air.*
- *The additional reductions in NOx emissions that would result from adding SCR or SNCR would come at a cost of about $0.7 to $1.3 million annually, with incremental NOx reductions in the 300 to 700 ton/year range. This cost range does not include costs related to redesign of the site layout to accommodate existing spatial constraints. Also, this estimate is based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-2008, it is difficult today to justify additional technology retrofits to reduce NOx emissions at this facility.*
- *For SNCR, the total annual cost is estimated to be about $730,000, or $1,030/ton of NOx removed. For an SCR system, the total annual cost is estimated to be $1,410,000 or $1,180/ton. SCR and SNCR are not cost-effective as Best Available Retrofit Technology for this facility and will not be considered further.*
- *Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NTI and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment.*

NPS: We agree that the reduced capacity utilization makes it difficult today to justify additional technology retrofits[4] to reduce NOx emissions at this facility. NHDES should

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[4] *NHDES has approved SCR (and the associated issues with ammonia) at Merrimack and must explain how it arrived at its estimate for ammonia slip and why ammonia is more of a problem at Newington. If NHDES believes that ammonia slip will impair visibility, it must show why that outweighs the benefits of reducing NOx.*

- ▶ NHDES Response: The issue is not so much the magnitude of ammonia slip or visibility impairment as it is the fact that ammonia slip would occur at all. For a situation such as this one in which SCR or SNCR is essentially ruled out as not cost-effective, ammonia slip only adds to the list of reasons for not implementing either technology.

propose federally-enforceable BART limit(s) that reflect its BART determination

- ▶ NHDES Response: Because additional retrofits are not proposed for Unit NT1, the BART assessment for this facility revolves around its long-term performance capability. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NOx emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NOx RACT limit of 0.25 lb/MMBtu, daily average, when burning natural gas and 0.35 lb/MMBtu, daily average, when burning fuel oil. However, the volume of the data record is insufficient to demonstrate that the facility could sustainably meet more restrictive emission limits. The current NOx RACT limitations for Unit NT1 are therefore considered to represent the BART control levels.

BART Analysis for PM

STEP 1 – Identify all available retrofit emissions control techniques

NHDES: The only PM control technologies available and potentially applicable to Unit NT1 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

NPS: NHDES should have considered simple, inexpensive upgrades for the ESPs to achieve greater control.

- ▶ NHDES Response: It may be technically feasible to install upgrades such as replacement of the existing ESP control systems with newer electronic controllers or replacing old-style wire and plate systems inside the ESP with new, rigid electrode systems. The problem arises in the cost-effectiveness of such measures. Specifically, it is difficult to justify any major capital expense at this facility in light of its recent operating record. Since 2006, the plant's capacity factor has been below 10 percent. Preliminary data for the first nine months of 2009 indicate that the plant was effectively offline for all but the first month.

STEP 2 – Eliminate technically infeasible options

NPS: No PM control options were eliminated on this basis.

STEP 3 – Evaluate control effectiveness of remaining control options

NHDES: Existing electrostatic precipitators (ESPs) are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent. Collection efficiencies of baghouses may exceed 99 percent.

NPS: NHDES assumed 42% for the existing ESP at Newington. Because this is far short of the capabilities of a rebuilt ESP, NHDES should have evaluated that option.

- ▶ NHDES Response: The 42 percent efficiency value was obtained by comparing the PM emission factor from a 2001 controlled stack test report with an AP-42 emission factor for uncontrolled PM, and is therefore a crude approximation of particulate removal efficiency. NHDES has located a 1971 performance specification for this unit from Buell Envirotech Corp. The efficiency is stated as 93 percent under normal operating conditions and a maximum of 98 percent under design conditions.

It is unknown whether these higher control rates are representative of the unit's actual long-term performance. The emission rate calculated from the 2001 stack testing (the only data available) was 0.058 lb/MMBtu. This emission rate is within the expected range for a properly operating ESP at a plant like Newington and may be a better measure of performance than the stated efficiencies.

STEP 4 – Impact analysis

NHDES: The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $3.2 million to $10.4 million, or $14,000 to $63,000 per ton of PM removed, Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only.

NPS: NHDES should have evaluated upgrading the ESP.

- NHDES Response: Please refer to previous response on upgrades.

Determination of BART for PM

NHDES: PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Because of the estimated cost differential and the fact that an ESP is already installed and operating, the existing ESP is determined to satisfy BART requirements for PM removal at PSNH Newington Station Unit NT1.

NPS: However, NHDES has assumed that the existing ESP is only 42% efficient – which is not "similar' to a fabric filter. NHDES should propose a limit that reflects the 99% control it assumed in its analyses for a new ESP or fabric filter. Although the existing ESPs may well represent BART, NHDES should evaluate possible upgrades, or, at least, establish a federally-enforceable permit limit that reflects the actual capabilities of the unit.

- NHDES Response: The single available stack test indicates that the ESP at Unit NT1 produces controlled emission rates in the vicinity of 0.06 lb/MMBtu. For comparison, the existing TSP limit is 0.22 lb/MMBtu (Permit TV-OP-054, March 9, 2007; administrative amendment, December 17, 2007). The extent of the data record is insufficient to support consideration of a BART performance level more restrictive than the current permit limit. The facility's Title V operating permit requires that a compliance stack test for PM emissions be performed on Unit NT1 before the permit expires on March 31, 2012. NHDES will review the stack test results to ascertain the unit's performance and incorporate any new limit into a permit amendment by the permit expiration date, as appropriate. The permit expiration date precedes the effective date of proposed BART control measures by fifteen months.