ATTACHMENT BB

Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®)

Final Draft Report

Comparison of CAIR and CAIR Plus Proposal using the Integrated Planning Model (IPM®)

Prepared for

Mid-Atlantic Regional Air Management Association (MARAMA)

Prepared by

ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

May 30, 2007

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A. Overview

MARAMA has awarded a contract to ICF Resources, L.L.C. (ICF), seeking ICF's services to evaluate the impact of EPA's CAIR Policy and the Mid-Atlantic/Northeast Visibility Union (MANE-VU) CAIR Plus proposal on the electric generating sector for the contiguous United States using the Integrated Planning Model (IPM®).

IPM is a dynamic linear optimization model that can be used to examine air pollution control policies for various pollutants throughout the contiguous U.S. for the entire electric power system. The dynamic nature of IPM enables the projection of the behavior of the power system over a specified future period. The optimization logic determines the least-cost means of meeting electric generation and capacity requirements while complying with specified constraints including air pollution regulations, transmission bottlenecks, and plant-specific operational constraints. The versatility of IPM allows users to specify which constraints to exercise and populate IPM with their own datasets.

This report summarizes the analysis that ICF has performed in evaluating the impact of the CAIR Plus proposal in the CAIR Plus region on the electricity generating sector by using IPM (hereafter, the analysis is referred to as the MARAMA analysis). As part of this analysis, ICF has also developed a Base Case that implements EPA's CAIR, CAMR and CAVR policies. The model assumptions and data used in this analysis are presented in Section B. The results are presented in Section C and the analysis limitations are presented in Section D.

Since the modeling is based on analyses developed by U.S. EPA, VISTAS and LADCO, we have summarized only the incremental changes that were proposed by MARAMA as part of this analysis. The documentation for EPA's v2.1.9 and v3.0 base cases is available at http://www.epa.gov/airmarkets/progsregs/epa-ipm. The VISTAS study assumptions are summarized in Appendix 1 and 2.

B. Modeling Assumptions and Changes Made to VISTAS Run

The MARAMA analysis is based on the recent IPM based analysis performed for VISTAS except for changes made by MARAMA. These runs are based on the VISTASII_PC_1f run that was developed for VISTAS in 2005. As per direction from MARAMA, the following assumptions for modeling the MARAMA Base Case-CAIR/CAMR/CAVR (MARAMA 5c) and MARAMA CAIR Plus Policy Case (MARAMA 4c) were implemented. Detailed assumptions are summarized in Appendix 3.

a) Run year configuration: The run year configuration was updated to separate out the key analysis years of 2009, 2012 and 2018. The revised configuration is summarized in Table 1:

Table 1: Run Years in MARAMA Base Case and MARAMA CAIR Plus Policy Case

Run Year	Calendar Years
2008	2007-2008
2009	2009-2009
2010	2010-2011
2012	2012-2012
2015	2013-2017
2018	2018-2018
2020	2019-2022
2026	2023-2030

b) Natural Gas Prices: As per direction from MARAMA, ICF implemented the EPA Base Case v3.0 natural gas supply curves that were based on ICF's NANGAS (North American Natural Gas Analysis System) model as part of this analysis. These gas supply curves are documented in the EPA Base Case v3.0 documentation published on its website. The gas supply curves used in the VISTAS analysis were based on the EPA Base Case v2.1.9. The gas supply curves used in the MARAMA analysis will result in higher gas prices as compared to the VISTAS analysis. For example, for a 5 quad gas consumption in the power sector, the Henry hub gas price using the EPA Base Case v3.0 gas supply curves will result in a gas price that is approximately 40-60% (based on the run year) higher than if EPA Base Case v2.1.9 gas supply curves were used.

c) Fuel Oil Prices: The fuel oil price projections from AEO 2006 were implemented in the MARAMA analysis and are higher as compared to the VISTAS analysis. The fuel oil price projections used in the VISTAS analysis were based on AEO 2005. The AEO 2006 assumptions are documented in the EPA Base Case v3.0.

d) SCR and Scrubber Feasibility Limits: Table 2 summarizes the cumulative SCR and scrubber feasibility limits that were implemented (in the MARAMA analysis) in the years 2008, 2009 and 2010. These limits are beyond existing control installations and prevent the model from projecting a level of SCR and scrubber builds in the short-term that was higher than the industry's capability to deliver. The feasibility limits in 2008 and 2009 are based on actual planned SCR and scrubber installations. The 2010 limit for scrubbers is based on a projection for installation of SO_2 scrubbers under CAIR. It is based on an internal analysis that accounted for the 2008/2009 feasibility limits. In the VISTAS study, feasibility limits for SCR and scrubbers were not applied in 2008, 2009 and 2010.

Note that in 2008, 2009 and 2010 run years, the individual unit level decisions were not hardwired but IPM will choose to build only the most economic SCRs and scrubbers up to those limits.

Table 2: Cumulative SCR and FGD Feasibility Limits in MARAMA Base Case and MARAMA CAIR Plus Policy Case Runs

Year	SCR (GW)	Scrubbers (GW)
2008	9	31
2009	15	51
2010	No Limit	69

Note: The above limits are incremental to those that are already installed on existing units as assumed in NEEDS.

e) CAVR (Clean Air Visibility Rule): Consistent with U.S. EPA's implementation of the CAVR rule, MARAMA has implemented the CAVR rule beginning in the run year 2015 within the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs.

> *CAVR SO_2 Requirements*: All CAVR eligible, unscrubbed, non CAIR and non WRAP affected sources larger than 200 MW are required to meet an output emission rate of 0.15 lbs/MMBtu of SO_2 or achieve 95% removal. However, only the option to meet the 0.15 lbs/MMBtu of SO_2 emission rate was provided in IPM. This assumption was based on the results from a comparison of output SO_2 emission rates of unscrubbed CAVR affected units in the VISTAS analysis when adjusted for a 95% removal with 0.15 lbs/MMBtu. The 0.15 lbs/MMBtu rate limit was always higher and hence is a lower cost strategy.

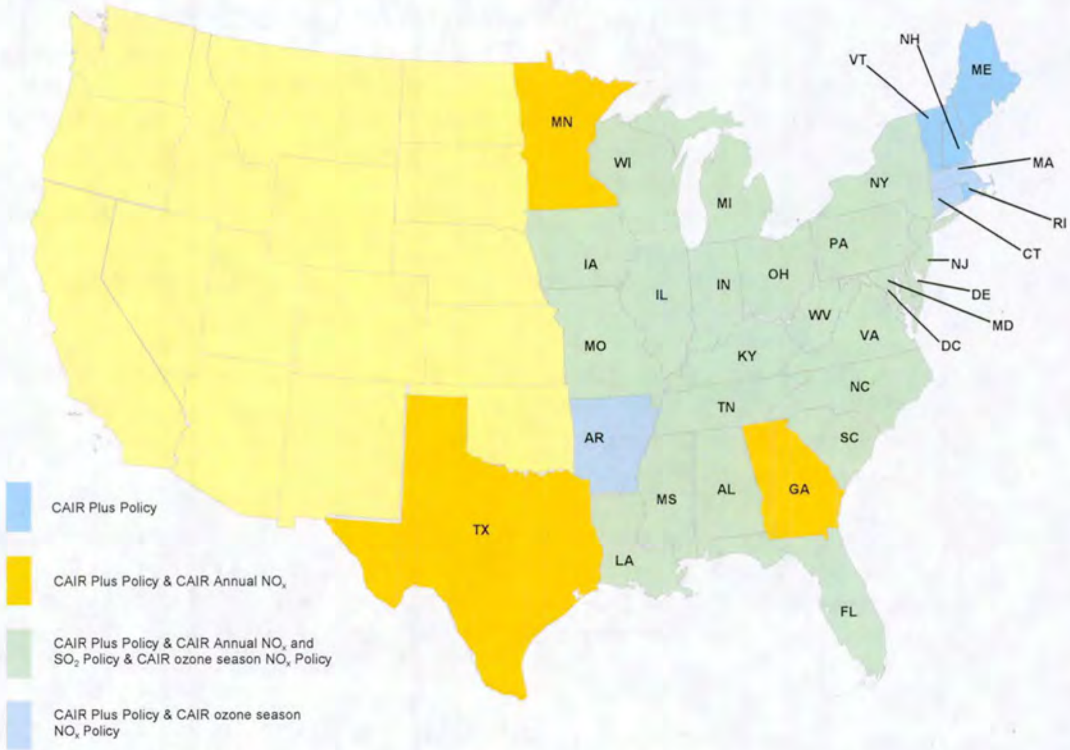
> *CAVR NO_x Requirements*: All CAVR eligible, non CAIR affected sources larger than 200 MW are required to install combustion controls. SCRs are also required if the affected units are cyclone fired. All existing SCRs are required to operate annually.

Note that CAVR eligible sources in the above discussion imply the list of CAVR affected sources that U.S. EPA had modeled in their CAVR analysis using IPM. A list of units affected by the CAVR SO_2 and NO_x requirements are shown in Appendix 3 (tables A3.5a and A3.5b respectively).

f) Title IV SO_2 Bank: The IPM modeling time period in the MARAMA analysis is 2007-2030. In order to capture the dynamics of the SO_2 allowance market pre 2007, MARAMA has implemented a Title IV SO_2 allowance bank of 6.43 million tons going into the year 2007. This assumption is based on an internal ICF analysis of the current market conditions.

g) Applicable States for Programs: The MARAMA CAIR Plus Policy Case run is based on the MARAMA Base Case run with the MARAMA CAIR Plus Policy Case proposal implemented as a replacement of the CAIR policy. Figure 1 shows a U.S. map with states affected by CAIR and CAIR Plus policies highlighted.

Figure 1: States affected by CAIR and MARAMA CAIR Plus Policies



h) <u>NO_x and SO_2 Budgets</u>: Table 3 summarizes the NO_x budgets implemented in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs, and Table 4 summarizes SO_2 allowance retirement ratios implemented in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. The NO_x budgets under the Base Case and CAIR Plus policy cases in Table 3 are not comparable because there are more states in the CAIR Plus domain as compared to the CAIR domain in the Base Case. In IPM, emissions budgets are modeled as a cap that all affected sources together are required to comply with. These sources can buy or sell emission allowances among themselves and bank for future use under favorable economics.

The SO_2 allowance retirement ratio is the number of Title IV SO_2 allowances that need to be surrendered for each ton of SO_2 emissions in the CAIR/CAIR Plus region. In IPM, a CAIR/CAIR Plus policy affected source is required to surrender the applicable number of Title IV SO_2 allowances determined by the SO_2 retirement ratio for every ton of SO_2 emission. A non CAIR/CAIR Plus policy affected source surrenders one Title IV SO_2 allowance for every ton of SO_2 emissions.

Table 3: NO_x Budgets in the CAIR/CAIR Plus Region (Thousand Tons)

	NO_x Ozone Season Budget		NO_x Annual Budget	
Year	MARAMA Base Case	MARAMA CAIR Plus Policy Case	MARAMA Base Case	MARAMA CAIR Plus Policy Case
2009	568	623	1,722*	1,553*
2010	568	623	1,522	1,353
2012	568	415	1,522	902
2015	518	395	1,370	858
2018	485	382	1,268	829

* Includes NO_x Compliance Supplement Pool of 199,997 tons included in 2009.

Note: The 2015 budgets as modeled in IPM are the average of the budgets over the period 2013-2017. The actual ozone season NO_x budgets proposed are 485 thousand tons in CAIR and 382 thousand tons in CAIR plus for 2015. The actual annual NO_x budgets proposed are 1,268 thousand tons in CAIR and 829 thousand tons in CAIR plus for 2015.

Table 4: SO_2 Allowance Retirement Ratios in the CAIR/CAIR Plus Region

	SO_2 Allowance Retirement Ratio	
Year	MARAMA Base Case	MARAMA CAIR Plus Policy Case
2009	1.00	1.00
2010	2.00	2.50
2012	2.00	2.94
2015	2.52	3.32
2018	2.86	4.16

Note: The 2015 retirement ratios as modeled in IPM are the average of the retirement ratios over the period 2013-2017. The actual retirement ratios are 2.86 for CAIR and 3.57 for CAIR Plus for 2015.

i) SO_2 and NO_x emission allowances were allowed to be banked in any year and then withdrawn from the bank in a future year under the CAIR program in the base case and the CAIR Plus programs.

C. Results

In this section, ICF has presented the costs, control installations, emissions, allowance market impacts, delivered fuel prices, generation, power plant retirements and new builds from the MARAMA Base Case and then compared these results with those from the MARAMA CAIR Plus Policy Case run. Appendix 5 summarizes the SO_2 and NO_x emission results and production cost components on a state and RPO level. The following paragraphs discuss the results from the two runs.

1. Production Costs

IPM projects the production cost of the U.S. power sector for each of the modeled run years. The production cost includes the annualized capital costs of new investment decisions (includes control equipment costs and new build costs), fuel costs and the total variable and fixed operation and maintenance (O&M) costs of power plants. Allowance costs are not listed as a separate category because on a region wide basis the net cost is zero (number of allowances purchased is equal to the number of allowances sold). The administrative costs related to the purchase and sale of allowances are not modeled in IPM. The annualized incremental cost[1] of the MARAMA CAIR Plus Policy as compared to MARAMA Base Case is summarized in Table 5. The analysis projects a total cost of $10.7 billion in 2009 & $2.6 billion in 2018 respectively. Note that the cost of the policy is highest in 2009 (higher fuel costs being the main contributor of higher production costs) and then decreases starting 2010. This is because in 2009 there are limitations to the number of units that can install SCRs. In 2010 however, these limits are relaxed. In order to comply with the tight NO_x regulations and the limitations on SCR installations, the power sector increases natural gas-fired generation. In 2009 in the MARAMA CAIR Plus Policy Case the gas consumption increases by 812 TBtu and $0.85/MMBtu. This increase in gas consumption and the gas price result in a spike in fuel costs. Note that these costs are for the entire U.S. power sector and the policy could affect states that are within and outside the CAIR Plus region.

Table 5: Incremental Cost of the MARAMA CAIR Plus Policy Case Compared to MARAMA Base Case -- US Power Sector (1999 Billion Dollars)

	2008	2009	2010	2012	2015	2018
Variable O&M Cost	0.04	0.01	0.32	0.51	0.41	0.28
Fixed O&M Cost	0.01	-0.03	0.12	0.29	0.20	0.13
Fuel Cost	0.04	10.40	0.17	-0.90	0.04	0.23
Annualized Capital Cost	0.26	0.31	1.58	2.43	2.12	1.93
Total Production Cost	0.36	10.69	2.19	2.33	2.77	2.57

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

The marginal costs[2] of emission reductions as manifested in the projected allowance prices in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case are shown in Table 6. The SO_2 and NO_x allowance prices in the CAIR Plus region in the MARAMA CAIR Plus Policy Case run are high starting in 2009 due to the relatively tighter policies applied to the CAIR Plus region as compared to the SO_2 and NO_x policies in the MARAMA Base Case. Tighter policies result in more expensive compliance options being chosen resulting in higher allowance prices. The NO_x allowance prices are high in 2009 and drop in 2010 because the SCR feasibility limits are relaxed starting in 2010. In 2009, due to limitations on SCR installations, a significant increase in natural gas fired generation occurs, driving up the annual NO_x allowance prices. Starting in 2010, SCRs are installed resulting in a reduction in the use of more expensive NO_x reduction options such as natural gas generation, driving down the annual NO_x allowance prices.

The compliance options available to power plants to reduce both annual NO_x emissions and the ozone season NO_x emissions are same. In addition the plants affected by the ozone season NO_x policy and the annual NO_x policy in the MARAMA CAIR Plus Policy Case are identical. A plant that installs a NO_x control option such as a SCR will be able to reduce emissions in both the ozone season and the non ozone season and hence simultaneously affect CAIR/CAIR Plus annual NO_x and ozone season NO_x allowance markets. It appears that complying with the annual NO_x policy results in an over compliance with the ozone season NO_x policy and is highlighted by the zero ozone season NO_x allowance price starting 2010.

[1] Annual Incremental Production Cost = Annualized Production Cost of MARAMA CAIR Plus Policy Case – Annualized Production Cost of MARAMA Base Case.
[2] Marginal cost is defined as the cost of reducing one additional ton of emissions.

Table 6: Allowance prices (Marginal Costs) of Emission Reductions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 $/ton)

CAIR/CAIR Plus Policy	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
SO_2	640	692	748	809	943	1,106
NO_x – Ozone[3]	14,580	15,760	0	0	0	0
NO_x - Annual	NA	3,047	1,149	1,155	1,337	1,567
MARAMA CAIR Plus Policy Case						
SO_2	806	872	942	1,019	1,188	1,392
difference wrt MARAMA Base Case	166	180	194	210	245	286
NO_x – Ozone	14,710	11,150	0	0	0	0
difference wrt MARAMA Base Case	130	-4,610	0	0	0	0
NO_x - Annual	NA	17,920	4,240	4,586	5,346	6,266
difference wrt MARAMA Base Case	NA	14,873	3,091	3,431	4,009	4,699

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856.

2. Projected Control Technology Retrofits

Installation of controls is one of the strategies that the power sector opts for complying with the CAIR Plus proposal requirements. This strategy is in addition to other compliance strategies such as changes to fuel switching, plant retirements, plant dispatch and new builds. Under the MARAMA CAIR Plus Policy Case, an additional 19.5 GW of SO_2 scrubbers and 77.8 GW of selective catalytic reduction (SCRs) are installed by 2012 (see Table 7). In the MARAMA CAIR Plus Policy Case, the SCR feasibility limits in 2008 and 2009 run years and the SO_2 scrubber limits in 2008 and 2010 run years are achieved.

Table 7: Incremental Pollution Control Installations by Technology in the MARAMA CAIR Plus Policy Case with the MARAMA Base Case (GW)

Technology	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Scrubber	24.9	31.4	59.7	65.6	87.5	98.7
SCR	9.0	15.0	38.5	42.1	58.6	66.3
MARAMA CAIR Plus Policy Case						
Scrubber	30.5	38.9	69.5	85.1	106.4	115.3
difference wrt MARAMA Base Case	5.6	7.5	9.8	19.5	18.9	16.6
SCR	9.0	15.0	115.2	120.0	124.5	131.2
difference wrt MARAMA Base Case	0.0	0.0	76.8	77.8	65.9	64.9

[3] The 2008 NO_x ozone season allowance price is for the SIP Call policy. Starting 2009 it is for the CAIR/CAIR Plus ozone season NO_x policy.

3. Emissions

Tables 8 and 9 summarize the SO_2 and NO_x emissions from all units including both fossil and nonfossil units in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case in the 2008, 2009, 2010, 2012, 2015 and 2018 run years. The projected state-level emissions for SO_2 and NO_x for the MARAMA CAIR Plus Policy Case and the MARAMA Base Case are presented in Tables A5.1-A5.3 in Appendix 5.

Note, that the CAIR/CAIR Plus policies are not applied to the WRAP region in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs, and hence the SO_2 and NO_x emissions in the two runs in the WRAP region are similar. The CAIR/CAIR Plus NO_x programs start in 2009. Hence, the NO_x emissions are lower starting in 2009. The NO_x emissions in CAIR Plus region in Table 9 do not match the corresponding NO_x budgets in Table 3 because NO_x emissions in Table 9 include emissions from both CAIR Plus affected and not affected units.

The CAIR/CAIR Plus SO_2 programs start in 2010. However, the SO_2 emissions are lower prior to 2010 because Title IV SO_2 allowances that are banked prior to 2010 can be used to comply with the CAIR/CAIR Plus provisions starting 2010.

Both the CAIR and CAIR Plus programs are cap and trade policies. Therefore, while the CAIR Plus policy is more stringent than the CAIR policy, emissions can still go up in individual states in MARAMA CAIR Plus Policy Case as compared to MARAMA Base Case.

Table 8: Annual SO_2 Emissions from the U.S. Electric Power Sector (All Units including Fossil and Non-fossil units) (Thousand Tons)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
MANE-VU	802.1	650.2	518.3	462.7	410.5	393.8
LADCO	1,950.5	1,785.1	1,594.8	1,593.4	1,490.5	1,437.7
VISTAS	2,879.6	2,702.0	2,094.5	1,981.2	1,689.7	1,398.2
CENRAP	1,395.3	1,391.1	1,397.3	1,385.4	1,158.9	1,136.8
WRAP	508.1	507.5	533.2	533.6	477.8	419.1
CAIR Plus Policy States	6,760.0	6,260.7	5,334.7	5,150.3	4,605.0	4,219.8
National Total	7,535.6	7,036.0	6,138.1	5,956.3	5,227.4	4,785.6
MARAMA CAIR Plus Policy Case						
MANE-VU	734.6	555.5	396.4	376.7	311.9	270.7
difference wrt MARAMA Base Case	-67.5	-94.8	-121.8	-86.0	-98.6	-123.1
LADCO	1,775.5	1,660.3	1,454.9	1,448.0	1,332.6	1,275.1
difference wrt MARAMA Base Case	-174.9	-124.8	-139.9	-145.4	-157.9	-162.6
VISTAS	2,696.8	2,049.4	1,769.9	1,461.5	1,190.6	991.8
difference wrt MARAMA Base Case	-182.9	-652.6	-324.7	-519.7	-499.1	-406.4
CENRAP	1,390.5	1,325.0	1,385.1	1,314.1	1,014.8	961.8
difference wrt MARAMA Base Case	-4.8	-66.1	-12.2	-71.3	-144.1	-175.0
WRAP	503.0	506.1	550.4	552.3	497.8	440.8
difference wrt MARAMA Base Case	-5.1	-1.4	17.1	18.7	20.0	21.7
CAIR Plus Policy States	6,331.6	5,324.1	4,735.4	4,325.7	3,705.2	3,350.8
difference wrt MARAMA Base Case	-428.4	-936.6	-599.3	-824.6	-899.8	-869.1
National Total	7,100.4	6,096.3	5,556.7	5,152.6	4,347.6	3,940.3
difference wrt MARAMA Base Case	-435.2	-939.7	-581.5	-803.8	-879.8	-845.3

Table 9: Annual NO_x Emissions from the U.S. Electric Power Sector (All Units including Fossil and Non-fossil units) (Thousand Tons)

MARAMA Base Case	2008	2009	2010	2012	2015	2018
MANE-VU	386.0	271.9	213.2	208.7	202.3	198.8
LADCO	803.9	483.4	413.0	409.0	389.5	382.1
VISTAS	1,207.6	699.9	622.0	621.1	502.0	452.9
CENRAP	754.5	604.1	603.0	616.0	539.4	538.3
WRAP	601.1	606.3	610.1	613.5	483.4	493.5
CAIR Plus Policy States	2,944.5	1,847.6	1,642.5	1,643.8	1,488.0	1,426.5
National Total	3,753.1	2,665.6	2,461.3	2,468.5	2,116.6	2,065.6
MARAMA CAIR Plus Policy Case						
MANE-VU	375.9	228.0	158.8	162.1	152.7	145.6
difference wrt MARAMA Base Case	-10.1	-43.9	-54.4	-46.7	-49.6	-53.2
LADCO	804.2	425.9	251.2	249.2	244.7	241.8
difference wrt MARAMA Base Case	0.4	-57.5	-161.8	-159.8	-144.8	-140.3
VISTAS	1,215.7	597.6	350.8	351.2	346.2	350.3
difference wrt MARAMA Base Case	8.0	-102.3	-271.2	-269.9	-155.8	-102.6
CENRAP	754.5	577.5	420.9	431.6	361.6	351.7
difference wrt MARAMA Base Case	0.1	-26.6	-182.1	-184.4	-177.8	-186.6
WRAP	600.5	606.5	610.0	615.2	485.5	495.7
difference wrt MARAMA Base Case	-0.6	0.2	-0.1	1.7	2.1	2.2
CAIR Plus Policy States	2,942.9	1,614.1	972.8	982.6	957.1	941.4
difference wrt MARAMA Base Case	-1.6	-233.4	-669.7	-661.2	-530.9	-485.1
National Total	3,750.9	2,435.5	1,791.6	1,809.3	1,590.7	1,585.1
difference wrt MARAMA Base Case	-2.2	-230.2	-669.7	-659.1	-525.8	-480.5

4. Allowance Market

Tables 10a and 10b summarize the CAIR/CAIR Plus SO_2 and NO_x allowance market as implemented in the CAIR/CAIR Plus region in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case.

The going into 2007 Title IV SO_2 bank is assumed to be 6.43 million tons. In IPM, SO_2 emission allowances are banked in 2008 and 2009 and withdrawn in subsequent years. Allowances are not banked in later years as the CAIR/CAIR Plus policy starts in 2010 resulting in reduced opportunities for over complying. Annual NO_x emission allowances are banked in 2010 and not in 2009 in the MARAMA CAIR Plus Policy Case because restrictions on SCR installations prevent over compliance of the NO_x cap in 2009.

Starting 2010 in both the CAIR/CAIR Plus ozone season NO_x policies, the number of ozone season NO_x allowances that are withdrawn from the bank are less than the allowances that are banked. This occurs because of a surplus of ozone season NO_x allowance availability and is highlighted by the zero ozone season NO_x allowance price. On a separate note, the allowances banked in the SIP Call budget program are allowed to be banked and used in the ozone season NO_x program starting in 2009. The going into 2007 NO_x SIP Call bank is assumed to be zero.

Table 10a: Summary of SO_2 and NO_x Allowance Market in MARAMA Base Case (Thousand Tons)

Run Year	2008	2009	2010	2012	2015	2018	2020
Years Mapped to Run Year	2007-2008	2009	2010-2011	2012-2012	2013-2017	2018	2019-2022
CAIR - SO_2							
Annual Emissions at Affected Units (Fossil Units > 25 MW)	7,333	6,831	5,942	5,760	5,029	4,586	4,171
Allowances Banked	5,245	2,449	0	0	0	0	0
Allowances Withdrawn from Bank	0	0	-1,072	-888	-1,072	-1,143	-722
CAIR – Ozone Season NO_x							
Ozone Season Emission Budget	497	568	568	568	518	485	485
Ozone Season Emissions at Affected Units (Fossil Units > 25 MW in CAIR Region)	492	579	558	558	502	482	465
Allowances Banked	5	0	10	10	16	3	20
Allowances Withdrawn from Bank	0	-11	0	0	0	0	0
CAIR – Annual NO_x							
Annual Emission Budget	NA	1,722	1,522	1,522	1,370	1,268	1,268
Annual Emissions at Affected Units (Fossil Units > 25 MW in CAIR Region)	NA	1,722	1,522	1,522	1,363	1,298	1,268
Allowances Banked	NA	0	0	0	6	0	0
Allowances Withdrawn from Bank	NA	0	0	0	0	-30	0

Note: The 2008 NO_x ozone season results reflect those from the SIP Call NO_x program and starting 2009 reflect those from the CAIR ozone season NO_x policy.

Table 10b: Summary of SO_2 and NO_x Allowance Market in MARAMA CAIR Plus Policy Case (Thousand Tons)

Run Year	2008	2009	2010	2012	2015	2018	2020
Years Mapped to Run Year	2007-2008	2009	2010-2011	2012-2012	2013-2017	2018	2019-2022
CAIR Plus - SO_2							
Annual Emissions at Affected Units (Fossil Units > 25 MW)	6,898	5,900	5,360	4,956	4,151	3,739	3,205
Allowances Banked	5,680	3,380	0	0	0	0	0
Allowances Withdrawn from Bank	0	0	-1,353	-1,424	-1,094	-1,234	-691
CAIR Plus – Ozone Season NO_x							
Ozone Season Emission Budget	497	623	623	416	395	382	382
Ozone Season Emissions at Affected Units (Fossil Units > 25 MW in CAIR Plus Region)	497	623	404	412	398	395	389
Allowances Banked	0	0	219	4	0	0	0
Allowances Withdrawn from Bank	0	0	0	0	-3	-13	-7
CAIR Plus – Annual NO_x							
Annual Emission Budget	NA	1,553	1,353	902	858	829	829
Annual Emissions at Affected Units (Fossil Units > 25 MW in CAIR Plus Region)	NA	1,553	918	927	898	882	867
Allowances Banked	NA	0	436	0	0	0	0
Allowances Withdrawn from Bank	NA	0	0	-25	-39	-53	-38

Note: The 2008 NO_x ozone season results reflect those from the SIP Call NO_x program and starting 2009 reflect those from the CAIR ozone season NO_x policy.

5. Fuel Consumption and Prices

Table 11a summarizes the coal and natural gas consumption in the U.S. power sector as projected by IPM in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. Table 11b summarizes the delivered coal and natural gas prices solved by IPM in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. The delivered gas prices are not inputs to the model but are determined endogenously by equilibrating demand and supply.

In the MARAMA Base Case, the natural gas prices in 2008 are higher than 2009. This is due to differences in the supply curves for the two years. As an example, for a gas consumption level of 5,696 TBtu, the gas price in 2008 is $7.23/MMbtu. However, at the same level of gas consumption, the gas price in 2009 would be at $6.12.

The fuel costs shown in Table 5 are incremental costs (i.e. MARAMA CAIR Plus Policy Case – MARAMA Base Case). The increase in fuel costs of $10.4 billion dollars in 2009 is a result of the incremental increase in natural gas prices of $0.85MMBtu between the two cases (i.e. $7.83/MMBtu in the CAIR Plus Policy case versus $6.98 in the MARAMA Base Case) and an increase in natural gas consumption 812 TBtu.

The gas prices are higher in most years in the MARAMA CAIR Plus Policy Case, in comparison to the MARAMA Base Case. This is a result of an increase in gas consumption as shifting from coal to gas is a compliance option leading to higher gas prices. In 2009 the gas prices increase is the highest because of restrictions on new SCR builds which result in an increase in gas consumption by 812 TBtu.

Table 11a: Fuel Consumption in MARAMA Base Case and MARAMA CAIR Plus Policy Case (TBtu)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal	22,938	22,706	25,594	26,050	27,489	29,198
Natural Gas	5,696	6,598	4,619	5,314	5,191	5,444
MARAMA CAIR Plus Policy Case						
Coal	22,863	21,503	25,396	26,099	27,318	28,699
difference wrt MARAMA Base Case	-76	-1,203	-198	49	-171	-500
Natural Gas	5,728	7,410	4,679	5,186	5,209	5,647
difference wrt MARAMA Base Case	32	812	60	-129	18	203

Table 11b: Delivered Fuel Prices in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 $/MMBtu)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal	1.09	1.08	1.07	1.05	1.03	1
Natural Gas	7.39	6.98	4.82	4.75	4.15	4.01
MARAMA CAIR Plus Policy Case						
Coal	1.09	1.06	1.06	1.04	1.02	0.99
difference wrt MARAMA Base Case	0	-0.02	-0.01	-0.01	-0.01	-0.01
Natural Gas	7.39	7.83	4.88	4.75	4.19	4.05
difference wrt MARAMA Base Case	0	0.85	0.06	0	0.04	0.04

6. Power Plant Retirements

A tighter environmental policy increases the total production costs of a power plant, including its compliance costs, and thus could make it uneconomic. Table 12 summarizes the power plant retirements in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. Note that the more stringent CAIR Plus policy results in an increase in total retirements by 4.9 GW in 2009. Oil/gas steam units that are uneconomic to run under the CAIR Plus policy retire. Increase in natural gas use as presented in Table 11a is accounted for by the remaining gas fired units that have relatively lower costs of operation.

Table 12: Power Plant Retirements in MARAMA CAIR Plus Policy Case with the MARAMA Base Case (MW)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	196	196	196	196	196	196
Combined Cycle	2,669	2,669	3,340	3,340	3,464	3,464
Combustion Turbine	2,804	2,804	3,143	3,143	3,143	3,143
Oil/Gas Steam	53,826	53,826	60,763	60,763	60,858	60,858
Other[1]	0	0	0	0	0	0
National Total	59,495	59,495	67,442	67,442	67,661	67,661
MARAMA CAIR Plus Policy Case						
Coal Steam	279	2,269	2,689	2,689	2,689	2,689
difference wrt MARAMA Base Case	83	2,073	2,493	2,493	2,493	2,493
Combined Cycle	2,822	2,822	3,540	3,540	3,541	3,541
difference wrt MARAMA Base Case	153	153	200	200	77	77
Combustion Turbine	2,804	2,804	3,143	3,143	3,143	3,143
difference wrt MARAMA Base Case	0	0	0	0	0	0
Oil/Gas Steam	56,467	56,467	63,023	63,023	63,023	63,023
difference wrt MARAMA Base Case	2,641	2,641	2,260	2,260	2,165	2,165
Other	0	0	0	0	0	0
difference wrt MARAMA Base Case	0	0	0	0	0	0
National Total	62,372	64,362	72,395	72,395	72,396	72,396
difference wrt MARAMA Base Case	2,877	4,867	4,953	4,953	4,735	4,735

Note: The category "Other" includes all plant types other than coal steam, oil/gas steam, combined cycle and combustion turbines.

7. Power Plant Generation

Changes in power plant generation is one of the compliance strategies for meeting a tighter environmental policy. In the MARAMA CAIR Plus Policy Case as compared to the MARAMA Base Case, the generation mix changes towards lower emission intensive fuel and plant types. Table 13 summarizes the generation mix in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. Note that there is an increase in natural gas fired generation (from combined cycles, combustion turbines and oil/gas steam units) and a reduction in coal fired generation (from coal steam and IGCC units) in all years except 2012. The overall increase in coal fired generation in 2012 occurs because it is the first year when the scrubber feasibility limits are no longer applicable resulting in an increase in scrubber installations and a relatively lower drop in generation from the coal steam units. Coal generation in 2010 is also not higher due to the presence of scrubber limits. In years after 2012, the SO_2 and NO_x policies in the MARAMA CAIR Plus Policy Case continue to become more stringent resulting in an increase in gas based generation.

The electricity demand in both the MARAMA Base Case and the MARAMA CAIR Plus Policy Case are identical. However the power generation in the two runs is different due to differences in transmission and pump storage losses.

Table 13: Generation by Plant Type in the U.S. Electric Power Sector (GWh)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	2,202,868	2,180,582	2,491,528	2,541,830	2,560,775	2,735,709
Combined Cycle	698,066	785,335	589,215	665,117	664,622	687,933
Combustion Turbine	37,735	49,113	30,941	38,341	36,254	49,527
Oil/Gas Steam	48,477	53,885	13,752	20,565	18,459	17,581
IGCC	4,702	4,702	14,142	14,148	192,239	226,262
Nuclear	796,130	796,715	797,725	801,460	810,065	807,698
Hydro (includes Pump Storage)	295,814	289,778	293,886	292,400	295,679	295,911
Biomass	14,301	14,929	17,039	22,183	25,969	29,742
Landfill Gas	13,715	13,747	13,747	13,747	16,063	16,384
Wind	32,308	32,414	32,664	32,782	34,486	36,289
Other	69,259	69,420	75,569	75,931	78,123	75,889
National Total	4,213,375	4,290,620	4,370,208	4,518,504	4,732,734	4,978,925
MARAMA CAIR Plus Policy Case						
Coal Steam	2,194,992	2,067,557	2,451,724	2,530,526	2,541,139	2,663,300
difference wrt MARAMA Base Case	-7,876	-113,025	-39,804	-11,304	-19,636	-72,409
Combined Cycle	703,266	889,217	598,711	650,084	671,380	736,610
difference wrt MARAMA Base Case	5,200	103,882	9,496	-15,033	6,758	48,677
Combustion Turbine	38,778	54,216	31,351	36,534	33,886	37,414
difference wrt MARAMA Base Case	1,043	5,103	410	-1,807	-2,368	-12,113
Oil/Gas Steam	46,979	55,463	12,714	19,655	18,028	17,755
difference wrt MARAMA Base Case	-1,498	1,578	-1,038	-910	-431	174
IGCC	4,702	4,702	41,408	41,408	205,343	259,435
difference wrt MARAMA Base Case	0	0	27,266	27,260	13,104	33,173
Nuclear	796,130	796,715	797,725	801,460	810,065	807,698
difference wrt MARAMA Base Case	0	0	0	0	0	0
Hydro (includes Pump Storage)	294,857	289,566	292,858	292,016	294,154	294,310
difference wrt MARAMA Base Case	-957	-212	-1,028	-384	-1,525	-1,601
Biomass	14,307	14,935	17,421	20,998	26,426	30,466
difference wrt MARAMA Base Case	6	6	382	-1,185	457	724
Landfill Gas	14,259	14,290	14,290	14,290	16,607	16,607
difference wrt MARAMA Base Case	544	543	543	543	544	223
Wind	34,522	34,627	34,877	34,936	35,383	37,187
difference wrt MARAMA Base Case	2,214	2,213	2,213	2,154	897	898
Other	69,259	68,125	75,569	75,931	78,123	75,889
difference wrt MARAMA Base Case	0	-1,295	0	0	0	0
National Total	4,212,051	4,289,413	4,368,648	4,517,838	4,730,534	4,976,671
difference wrt MARAMA Base Case	-1,324	-1,207	-1,560	-666	-2,200	-2,254

Note: The plant type "Other" includes solar, geothermal and waste fired units.

8. New Power Plant Builds

Table 14 summarizes the new power plant builds in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. In the MARAMA CAIR Plus Policy Case, new builds are higher than in the MARAMA Base Case because of a need to compensate for the increase in power plant retirements as presented in Table 12 and to take advantage of the relatively cleaner emission profiles of the new technologies.

New IGCC's have lower emission rates and lower heat rates making them more valuable under a stringent environmental policy. Hence IGCC's are built in 2010 and 2012 in the MARAMA CAIR Plus Policy Case and not in the MARAMA Base Case.

In 2018, the SO_2 allowance retirement ratio increases from 3.32 to 4.16. This increase results in a drop in coal fired generation and an increase in natural gas fired generation. In order to support this increase, in 2018 there is a significant increase in new combined cycle capacity that is more cost effective for base and intermediate load operation and a corresponding decrease in new combustion turbine capacity that is cost effective for peak load operation.

Table 14: New Power Plant Builds by Plant Type in the United States (MW)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	0	0	38,084	44,332	48,833	75,341
IGCC	0	0	0	0	23,187	27,617
Combined Cycle	6,550	6,550	6,550	8,580	20,518	24,265
Combustion Turbine	4,625	4,625	4,625	4,625	4,848	16,302
Biomass	0	0	349	978	1,570	2,099
Landfill Gas	1,241	1,241	1,241	1,241	1,552	1,595
Wind	5,153	5,153	5,153	5,193	5,739	6,283
National Total	17,569	17,569	56,002	64,949	106,247	153,502
MARAMA CAIR Plus Policy Case						
Coal Steam	0	0	35,674	46,627	52,245	72,806
difference wrt MARAMA Base Case	0	0	-2,410	2,295	3,412	-2,535
IGCC	0	0	3,651	3,651	24,995	32,038
difference wrt MARAMA Base Case	0	0	3,651	3,651	1,808	4,421
Combined Cycle	6,814	6,814	6,814	8,163	21,120	33,615
difference wrt MARAMA Base Case	264	264	264	-417	602	9,350
Combustion Turbine	4,781	4,781	4,781	4,781	4,781	10,473
difference wrt MARAMA Base Case	156	156	156	156	-67	-5,829
Biomass	0	0	349	815	1,570	2,099
difference wrt MARAMA Base Case	0	0	0	-163	0	0
Landfill Gas	1,314	1,314	1,314	1,314	1,625	1,625
difference wrt MARAMA Base Case	73	73	73	73	73	30
Wind	5,843	5,843	5,843	5,863	5,985	6,529
difference wrt MARAMA Base Case	690	690	690	670	246	246
National Total	18,752	18,752	58,426	71,214	112,321	159,185
difference wrt MARAMA Base Case	1,183	1,183	2,424	6,265	6,074	5,683

D. Limitations of Analysis

MARAMA modeling using IPM is based on various economic and engineering input assumptions that are inherently uncertain, such as assumptions for future fuel prices, electricity demand growth and the cost and performance of control technologies. As configured, IPM does not take into account demand response (i.e., consumer reaction to changes in electricity prices).

Appendix 1: Summary of Changes to EPA Base Case v2.1.9 by Vistas

The EPA Base Case v.2.1.9 was developed by ICF under the direction of the U.S. Environmental Protection Agency (EPA). It serves as the starting point for the analysis presented in this report. Subsequent to its release the VISTAS Regional Planning Organization initiated a two-phase study using IPM. Starting with the EPA 2.1.9 as a base, VISTAS, along with study participants from CENRAP and LADCO RPOs, made several changes to the underlying datasets and modeling assumptions. The starting point for the MARAMA analyses discussed in this report was work from the VISTAS study as modeled in the run VISTASII_PC_1f.

VISTAS and its workgroup initiated a review of NEEDS and recommended a large number of changes to the data. This occurred in two phases. In addition to unit level changes, VISTAS and its workgroup made a number of global changes that are reflected in this case. These are briefly described below:

- Demand forecast were changed to reflect unadjusted EIA AEO 2005 national electricity and peak demand values.

- AEO 2005 data was used for all assumptions regarding new builds of conventional technologies. The cost and performance assumptions for these units were as per the AEO 2005 documentation, while assumptions for renewable capacity were the same as those used in the EPA Base Case 2004 v.2.1.9.

- For nuclear units, the cost of continued operation was updated to approximately $27 per kilowatt-year based on AEO 2005.

- Hardwired Duke Power and Progress Energy control technology investment strategies for complying with the North Carolina Clean Smoke Stacks rule.

- The renewable portfolio standards (RPS) is modeled based on the most recent RGGI documentation using a single RPS region for Massachusetts (MA), Rhode Island (RI), New York (NY), New Jersey (NJ), Maryland (MD) and Connecticut (CT). The RPS requirements within these states can be met by renewable generation from New England, New York and PJM. EPA Base Case 2004 v.2.1.9 methodology and EIA AEO 2004 projected renewable builds were used for the rest of the regions.

- The run years used were 2008 (2007-2008), 2009 (2009), 2012 (2010-2013), 2015 (2014-2017), 2018 (2018), 2020 (2019-2022), and 2026 (2023-2030).

- The Clean Air Mercury Rule (CAMR) was modeled.

Appendix 2: MANE-VU IPM Global Parameter Decisions

This section summarizes the decisions as made by MANE-VU for global assumptions to be used in EGU forecasting with IPM as part of the VISTAS analysis. These decisions and changes are made to EPA Base Case version 2.1.9 assumptions.

A. Market Assumptions

1. National Electricity and Peak Demand

Decision: Use unadjusted EIA AEO 2005 national electricity and peak demand values.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Regional Electricity and Demand Breakout

Decision: Use the existing IPM region breakdown as conducted in earlier modeling.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

3. Natural Gas Supply Curve and Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Megan Schuster dated 7/5/05.)

4. Oil Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Meagan Schuster dated 7/5/05.)

5. Coal Supply and Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Megan Schuster dated 7/1/05.)

B. Technical Assumptions

1. Firmly Planned Capacity Assumptions

Decision: Use revisions and new data as provided by RPOs and stakeholders.
Decision: Allow NC Clean Smokestacks 2009 data as provided to define "must run" units.
(These are the same as the assumptions used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Pollution Control Retrofit Cost and Performance [SO2, NOx, Hg]

Decision: Retain pollution control retrofit cost and performance values.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

3. New Conventional Capacity cost and performance assumptions

Decision: Use EIA AEO 2005 cost and performance assumptions for new conventional capacity.
Decision: Retain existing 2.1.9 framework cost and performance for new renewable capacity.
Decision: Exclude constraint on new capacity type builds (i.e., no new coal).
(These are the same as the assumptions used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

4. SO_2 Title IV Allowance Bank

Decision: Use existing SO2 allowance bank value (4.99 million tons) for 2007.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

5. Nuclear Re-licensing and Uprate

Decision: Use existing IPM configuration with updated EIA AEO 2005 (~$27/kW) incurrence cost for continued operation.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

C. Strategy Assumptions

1. Clear Air Mercury Rule (CAMR)

Decision: Include CAMR in future rounds of IPM modeling.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Renewable Portfolio Standards

Decision: Model RPS based on the most recent RGGI documentation using a single RPS region for MA, RI, NY, NJ, MD and CT. The RPS requirements within these states can be met by renewable generation from New England, New York and PJM. EPA 2.1.9 methodology and hardwired EIA AEO 2004 projected renewable builds for the remainder of the country.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

D. Other Assumptions

1. Run Years

Decision: Parsed output data will be provided for 2009, 2012 and 2018.
Run years to 2008, 2009, 2012, 2015, 2018, 2020, and 2026.
(Run Year 2008 [2007-2008], Run Year 2009 [2009], Run Year 2012 [2010-2013], Run Year 2015 [2014-2017], Run Year 2018 [2018], Run Year 2020 [2019-2022] and Run Year 2026 [2023-2030]
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Canadian Sources

Decision: Utilize existing v.2.1.9 configuration (no Canadian site specific sources).
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

Appendix 3: Detailed Assumptions Used in MARAMA analysis

Table A.3.1 shows the run year configuration used in the MARAMA Base Case and Policy Case.

Table A.3.1 Run Year Configuration

Run Year	Calendar Years
2008	2007-2008
2009	2009-2009
2010	2010-2011
2012	2012-2012
2015	2013-2017
2018	2018-2018
2020	2019-2022
2026	2023-2030

Table A3.2 shows the natural gas prices used in the MARAMA analysis. These supply curves are based on ICF's NANGAS model.

Table A3.2 Natural Gas Supply Curve in the MARAMA Analysis

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2008	3.50	20987	21160	173
2008	3.63	20734	21230	496
2008	3.78	20493	21300	807
2008	3.91	20264	21360	1096
2008	4.05	20045	21420	1375
2008	4.19	19836	21480	1644
2008	4.32	19635	21540	1905
2008	4.47	19443	21600	2157
2008	4.60	19258	21660	2402
2008	4.75	19080	21710	2630
2008	4.88	18909	21760	2851
2008	5.01	18744	21810	3066
2008	5.16	18585	21860	3275
2008	5.29	18432	21910	3478
2008	5.44	18284	21960	3676
2008	5.57	18141	22010	3869
2008	5.71	18002	22060	4058
2008	5.85	17868	22100	4232
2008	5.98	17738	22140	4402
2008	6.12	17612	22180	4568
2008	6.26	17489	22220	4731
2008	6.40	17370	22260	4890
2008	6.54	17254	22300	5046
2008	6.67	17141	22340	5199
2008	6.81	17031	22380	5349
2008	6.95	16924	22420	5496
2008	7.09	16820	22460	5640
2008	7.23	16719	22500	5781
2008	7.36	16620	22540	5920
2008	7.50	16524	22570	6046
2008	7.64	16430	22600	6170
2008	7.78	16338	22630	6292
2008	7.92	16248	22660	6412
2008	8.06	16160	22690	6530
2008	8.19	16074	22720	6646
2008	8.33	15990	22750	6760
2008	8.47	15908	22780	6872
2008	8.61	15828	22810	6982
2008	8.75	15749	22840	7091
2008	8.88	15672	22870	7198
2008	9.02	15596	22900	7304
2008	9.16	15522	22930	7408
2008	9.30	15449	22960	7511
2008	9.44	15378	22990	7612
2008	9.57	15308	23020	7712

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2008	9.72	15239	23050	7811
2009	3.22	21520	22270	750
2009	3.36	21235	22340	1105
2009	3.50	20965	22410	1445
2009	3.63	20709	22480	1771
2009	3.78	20465	22540	2075
2009	3.91	20233	22600	2367
2009	4.05	20011	22660	2649
2009	4.19	19799	22720	2921
2009	4.32	19596	22780	3184
2009	4.47	19401	22830	3429
2009	4.60	19214	22880	3666
2009	4.75	19034	22930	3896
2009	4.88	18861	22980	4119
2009	5.01	18695	23030	4335
2009	5.16	18535	23080	4545
2009	5.29	18380	23130	4750
2009	5.44	18230	23180	4950
2009	5.57	18085	23220	5135
2009	5.71	17945	23260	5315
2009	5.85	17809	23300	5491
2009	5.98	17677	23340	5663
2009	6.12	17549	23380	5831
2009	6.26	17425	23420	5995
2009	6.40	17305	23460	6155
2009	6.54	17188	23500	6312
2009	6.67	17074	23540	6466
2009	6.81	16963	23580	6617
2009	6.95	16855	23620	6765
2009	7.09	16750	23660	6910
2009	7.23	16648	23690	7042
2009	7.36	16548	23720	7172
2009	7.50	16451	23750	7299
2009	7.64	16356	23780	7424
2009	7.78	16263	23810	7547
2009	7.92	16172	23840	7668
2009	8.06	16083	23870	7787
2009	8.19	15996	23900	7904
2009	8.33	15911	23930	8019
2009	8.47	15828	23960	8132
2009	8.61	15747	23990	8243
2009	8.75	15668	24020	8352
2009	8.88	15590	24050	8460
2009	9.02	15514	24080	8566
2009	9.16	15439	24110	8671
2009	9.30	15366	24140	8774
2009	9.44	15294	24170	8876
2009	9.57	15224	24200	8976
2009	9.72	15155	24230	9075

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2010	3.22	21688	23220	1532
2010	3.36	21387	23300	1913
2010	3.50	21102	23370	2268
2010	3.63	20832	23440	2608
2010	3.78	20575	23510	2935
2010	3.91	20330	23580	3250
2010	4.05	20097	23640	3543
2010	4.19	19874	23700	3826
2010	4.32	19661	23760	4099
2010	4.47	19457	23820	4363
2010	4.60	19261	23880	4619
2010	4.75	19073	23940	4867
2010	4.88	18892	23990	5098
2010	5.01	18717	24040	5323
2010	5.16	18549	24090	5541
2010	5.29	18387	24140	5753
2010	5.44	18230	24190	5960
2010	5.57	18078	24240	6162
2010	5.71	17931	24290	6359
2010	5.85	17789	24340	6551
2010	5.98	17651	24390	6739
2010	6.12	17518	24430	6912
2010	6.26	17388	24470	7082
2010	6.40	17262	24510	7248
2010	6.54	17140	24550	7410
2010	6.67	17021	24590	7569
2010	6.81	16905	24630	7725
2010	6.95	16793	24670	7877
2010	7.09	16683	24710	8027
2010	7.23	16576	24750	8174
2010	7.36	16472	24790	8318
2010	7.50	16371	24830	8459
2010	7.64	16272	24870	8598
2010	7.78	16175	24910	8735
2010	7.92	16081	24940	8859
2010	8.06	15989	24970	8981
2010	8.19	15899	25000	9101
2010	8.33	15811	25030	9219
2010	8.47	15725	25060	9335
2010	8.61	15641	25090	9449
2010	8.75	15558	25120	9562
2010	8.88	15477	25150	9673
2010	9.02	15398	25180	9782
2010	9.16	15320	25210	9890
2010	9.30	15244	25240	9996
2010	9.44	15169	25270	10101
2010	9.57	15096	25300	10204
2010	9.72	15024	25330	10306
2012	3.22	22121	24260	2139

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2012	3.36	21813	24350	2537
2012	3.50	21522	24430	2908
2012	3.63	21246	24510	3264
2012	3.78	20983	24590	3607
2012	3.91	20733	24670	3937
2012	4.05	20494	24740	4246
2012	4.19	20266	24810	4544
2012	4.32	20048	24880	4832
2012	4.47	19839	24950	5111
2012	4.60	19638	25020	5382
2012	4.75	19445	25080	5635
2012	4.88	19259	25140	5881
2012	5.01	19080	25200	6120
2012	5.16	18908	25260	6352
2012	5.29	18742	25320	6578
2012	5.44	18582	25380	6798
2012	5.57	18427	25430	7003
2012	5.71	18277	25480	7203
2012	5.85	18132	25530	7398
2012	5.98	17991	25580	7589
2012	6.12	17854	25630	7776
2012	6.26	17722	25680	7958
2012	6.40	17593	25730	8137
2012	6.54	17468	25780	8312
2012	6.67	17346	25830	8484
2012	6.81	17228	25880	8652
2012	6.95	17113	25920	8807
2012	7.09	17001	25960	8959
2012	7.23	16892	26000	9108
2012	7.36	16786	26040	9254
2012	7.50	16682	26080	9398
2012	7.64	16581	26120	9539
2012	7.78	16482	26160	9678
2012	7.92	16385	26200	9815
2012	8.06	16291	26240	9949
2012	8.19	16199	26280	10081
2012	8.33	16109	26320	10211
2012	8.47	16021	26360	10339
2012	8.61	15935	26400	10465
2012	8.75	15851	26440	10589
2012	8.88	15768	26480	10712
2012	9.02	15687	26520	10833
2012	9.16	15608	26550	10942
2012	9.30	15530	26580	11050
2012	9.44	15454	26610	11156
2012	9.57	15379	26640	11261
2012	9.72	15306	26670	11364
2015	3.22	22107	25450	3343
2015	3.36	21844	25540	3696

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2015	3.50	21595	25620	4025
2015	3.63	21358	25700	4342
2015	3.78	21132	25780	4648
2015	3.91	20917	25850	4933
2015	4.05	20711	25920	5209
2015	4.19	20514	25990	5476
2015	4.32	20325	26060	5735
2015	4.47	20144	26130	5986
2015	4.60	19970	26190	6220
2015	4.75	19802	26250	6448
2015	4.88	19641	26310	6669
2015	5.01	19485	26370	6885
2015	5.16	19335	26430	7095
2015	5.29	19190	26490	7300
2015	5.44	19050	26540	7490
2015	5.57	18914	26590	7676
2015	5.71	18782	26640	7858
2015	5.85	18654	26690	8036
2015	5.98	18530	26740	8210
2015	6.12	18410	26790	8380
2015	6.26	18293	26840	8547
2015	6.40	18180	26890	8710
2015	6.54	18070	26940	8870
2015	6.67	17963	26980	9017
2015	6.81	17858	27020	9162
2015	6.95	17756	27060	9304
2015	7.09	17657	27100	9443
2015	7.23	17560	27140	9580
2015	7.36	17466	27180	9714
2015	7.50	17374	27220	9846
2015	7.64	17284	27260	9976
2015	7.78	17196	27300	10104
2015	7.92	17110	27340	10230
2015	8.06	17026	27380	10354
2015	8.19	16944	27420	10476
2015	8.33	16863	27460	10597
2015	8.47	16784	27500	10716
2015	8.61	16707	27540	10833
2015	8.75	16631	27570	10939
2015	8.88	16557	27600	11043
2015	9.02	16484	27630	11146
2015	9.16	16413	27660	11247
2015	9.30	16343	27690	11347
2015	9.44	16274	27720	11446
2015	9.57	16207	27750	11543
2015	9.72	16141	27780	11639
2018	3.22	23169	26880	3711
2018	3.36	22871	27010	4139
2018	3.50	22589	27130	4541

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2018	3.63	22321	27250	4929
2018	3.78	22066	27360	5294
2018	3.91	21823	27470	5647
2018	4.05	21591	27580	5989
2018	4.19	21369	27680	6311
2018	4.32	21156	27780	6624
2018	4.47	20952	27880	6928
2018	4.60	20756	27980	7224
2018	4.75	20568	28070	7502
2018	4.88	20387	28160	7773
2018	5.01	20212	28250	8038
2018	5.16	20044	28340	8296
2018	5.29	19881	28420	8539
2018	5.44	19724	28500	8776
2018	5.57	19572	28580	9008
2018	5.71	19425	28660	9235
2018	5.85	19282	28740	9458
2018	5.98	19144	28820	9676
2018	6.12	19010	28890	9880
2018	6.26	18880	28960	10080
2018	6.40	18753	29030	10277
2018	6.54	18630	29100	10470
2018	6.67	18510	29170	10660
2018	6.81	18394	29240	10846
2018	6.95	18281	29310	11029
2018	7.09	18170	29380	11210
2018	7.23	18062	29440	11378
2018	7.36	17957	29500	11543
2018	7.50	17854	29560	11706
2018	7.64	17754	29620	11866
2018	7.78	17656	29680	12024
2018	7.92	17560	29740	12180
2018	8.06	17467	29800	12333
2018	8.19	17376	29860	12484
2018	8.33	17287	29920	12633
2018	8.47	17200	29980	12780
2018	8.61	17114	30030	12916
2018	8.75	17030	30080	13050
2018	8.88	16948	30130	13182
2018	9.02	16868	30180	13312
2018	9.16	16789	30230	13441
2018	9.30	16712	30280	13568
2018	9.44	16636	30330	13694
2018	9.57	16562	30380	13818
2018	9.72	16489	30430	13941
2020	3.22	23815	26120	2305
2020	3.36	23496	26280	2784
2020	3.50	23194	26440	3246
2020	3.63	22907	26590	3683

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2020	3.78	22634	26740	4106
2020	3.91	22374	26880	4506
2020	4.05	22126	27020	4894
2020	4.19	21889	27150	5261
2020	4.32	21662	27280	5618
2020	4.47	21445	27410	5965
2020	4.60	21236	27530	6294
2020	4.75	21035	27650	6615
2020	4.88	20842	27770	6928
2020	5.01	20656	27880	7224
2020	5.16	20477	27990	7513
2020	5.29	20304	28100	7796
2020	5.44	20137	28210	8073
2020	5.57	19975	28310	8335
2020	5.71	19818	28410	8592
2020	5.85	19666	28510	8844
2020	5.98	19519	28610	9091
2020	6.12	19376	28710	9334
2020	6.26	19238	28800	9562
2020	6.40	19104	28890	9786
2020	6.54	18973	28980	10007
2020	6.67	18846	29070	10224
2020	6.81	18722	29160	10438
2020	6.95	18602	29250	10648
2020	7.09	18485	29340	10855
2020	7.23	18371	29420	11049
2020	7.36	18260	29500	11240
2020	7.50	18151	29580	11429
2020	7.64	18045	29660	11615
2020	7.78	17941	29740	11799
2020	7.92	17840	29820	11980
2020	8.06	17741	29900	12159
2020	8.19	17644	29980	12336
2020	8.33	17550	30050	12500
2020	8.47	17458	30120	12662
2020	8.61	17368	30190	12822
2020	8.75	17279	30260	12981
2020	8.88	17192	30330	13138
2020	9.02	17107	30400	13293
2020	9.16	17024	30470	13446
2020	9.30	16942	30540	13598
2020	9.44	16862	30610	13748
2020	9.57	16783	30680	13897
2020	9.72	16706	30750	14044

Table A3.3 shows the fuel oil prices used in the MARAMA analysis. These prices based on AEO 2006.

Table A3.3 Residual and Distillate Fuel Oil Prices (1999$/MMBtu)

	Residual Oil		Distillate Oil	
Year	MAAC	New England	MAAC	New England
2008	5.13	4.41	8.63	8.69
2009	5.00	4.13	8.30	8.38
2010	4.88	3.87	7.98	8.05
2012	4.75	3.83	8.06	8.12
2015	4.75	3.77	7.90	7.96
2018	5.03	3.90	8.27	8.33
2020	5.06	3.98	8.41	8.47
Source: AEO 2006				

Table A3.4 summarizes the cumulative SCR and scrubber feasibility limits that were implemented in the years 2008, 2009 and 2010. These limits are based on projections of planned installations.

Table A3.4 SCR and Scrubber Feasibility Limits

Year	SCR (GW)	Scrubbers (GW)
2008	9	31
2009	15	51
2010	No Limit	69

Tables A3.5a and 3.5b show the list of CAVR eligible sources for SO_2 and NO_x requirements.

Table A3.5a CAVR SO_2 Requirements: All CAVR eligible, unscrubbed, non CAIR and non WRAP affected sources larger than 200 MW

Unique ID	Plant Name	State
6138_B_1	Flint Creek	Arkansas
6641_B_1	Independence	Arkansas
6009_B_1	White Bluff	Arkansas
6009_B_2	White Bluff	Arkansas
469_B_4	Cherokee	Colorado
470_B_1	Comanche	Colorado
470_B_2	Comanche	Colorado
6248_B_1	Pawnee	Colorado
8219_B_1	Rray d Nixon	Colorado
568_B_BHB3	Bridgeport Harbor	Connecticut
1241_B_2	La Cygne	Kansas
6064_B_N1	Nearman Creek	Kansas
1619_B_1	Brayton Point	Massachusetts
1619_B_2	Brayton Point	Massachusetts
1619_B_3	Brayton Point	Massachusetts
2817_B_1	leland Olds	North Dakota
2817_B_2	leland Olds	North Dakota
2823_B_B1	Milton R Young	North Dakota
6077_B_1	Gerald Gentleman	Nebraska
6077_B_2	Gerald Gentleman	Nebraska
6096_B_1	Nebraska City	Nebraska
2291_B_5	North Omaha	Nebraska
2364_B_2	Merrimack	New Hampshire
8224_B_1	North Valmy	Nevada
2952_B_4	Muskogee	Oklahoma
2952_B_5	Muskogee	Oklahoma
2963_B_3313	Northeastern	Oklahoma
2963_B_3314	Northeastern	Oklahoma
6095_B_1	Sooner	Oklahoma
6095_B_2	Sooner	Oklahoma
6098_B_1	Big Stone	South Dakota

Table A3.5b CAVR NO_X Requirements: CAVR eligible, non CAIR affected sources larger than 200 MW

Unique ID	Plant Name	State
6138_B_1	Flint Creek	Arkansas
6641_B_1	Independence	Arkansas
6009_B_1	White Bluff	Arkansas
6009_B_2	White Bluff	Arkansas
113_B_2	Cholla	Arizona
113_B_3	Cholla	Arizona
113_B_4	Cholla	Arizona
6177_B_U1B	Coronado	Arizona
6177_B_U2B	Coronado	Arizona
4941_B_1	Navajo	Arizona
4941_B_2	Navajo	Arizona
4941_B_3	Navajo	Arizona
469_B_4	Cherokee	Colorado
470_B_1	Comanche	Colorado
470_B_2	Comanche	Colorado
6021_B_C1	Craig	Colorado
6021_B_C2	Craig	Colorado
525_B_H2	Hayden	Colorado
6248_B_1	Pawnee	Colorado
8219_B_1	Ray D Nixon	Colorado
568_B_BHB3	Bridgeport Harbor	Connecticut
6068_B_1	Jeffrey Energy Center	Kansas
6068_B_2	Jeffrey Energy Center	Kansas
1241_B_1	La Cygne	Kansas
1241_B_2	La Cygne	Kansas
1250_B_5	Lawrence	Kansas
6064_B_N1	Nearman Creek	Kansas
1619_B_1	Brayton Point	Massachusetts
1619_B_2	Brayton Point	Massachusetts
1619_B_3	Brayton Point	Massachusetts
6076_B_1	Colstrip	Montana
6076_B_2	Colstrip	Montana
6030_B_1	Coal Creek	North Dakota
6030_B_2	Coal Creek	North Dakota
2817_B_1	Leland Olds	North Dakota
2817_B_2	Leland Olds	North Dakota
2823_B_B1	Milton R Young	North Dakota
2823_B_B2	Milton R Young	North Dakota
6077_B_1	Gerald Gentleman	Nebraska
6077_B_2	Gerald Gentleman	Nebraska
6096_B_1	Nebraska City	Nebraska
2291_B_5	North Omaha	Nebraska
2364_B_2	Merrimack	New Hampshire
2442_B_3	Four Corners	New Mexico
2442_B_4	Four Corners	New Mexico
2442_B_5	Four Corners	New Mexico
2451_B_1	San Juan	New Mexico
2451_B_2	San Juan	New Mexico

Unique ID	Plant Name	State
2451_B_3	San Juan	New Mexico
2451_B_4	San Juan	New Mexico
2341_B_1	Mohave	Nevada
2341_B_2	Mohave	Nevada
8224_B_1	North Valmy	Nevada
2952_B_4	Muskogee	Oklahoma
2952_B_5	Muskogee	Oklahoma
2963_B_3313	Northeastern	Oklahoma
2963_B_3314	Northeastern	Oklahoma
6095_B_1	Sooner	Oklahoma
6095_B_2	Sooner	Oklahoma
6106_B_1SG	Boardman	Oregon
6098_B_1	Big Stone	South Dakota
6165_B_1	Hunter (Emery)	Utah
6165_B_2	Hunter (Emery)	Utah
8069_B_1	Huntington	Utah
8069_B_2	Huntington	Utah
3845_B_BW21	Centralia	Washington
3845_B_BW22	Centralia	Washington
4158_B_BW43	Dave Johnston	Wyoming
4158_B_BW44	Dave Johnston	Wyoming
8066_B_BW71	Jim Bridger	Wyoming
8066_B_BW72	Jim Bridger	Wyoming
8066_B_BW73	Jim Bridger	Wyoming
8066_B_BW74	Jim Bridger	Wyoming
6204_B_1	Laramie River	Wyoming
6204_B_2	Laramie River	Wyoming
6204_B_3	Laramie River	Wyoming
4162_B_2	Naughton	Wyoming
4162_B_3	Naughton	Wyoming
6101_B_BW91	Wyodak	Wyoming

Title IV SO_2 bank – In order to capture the dynamics of the SO_2 allowance market pre 2007, MARAMA has implemented a Title IV SO_2 allowance bank of 6.43 million tons, going into the year 2007.

Tables A3.6 and A3.7 show the national regulations modeled in the MARAMA base case and policy cases respectively, along with the details regarding affected units, policy structure and amount of allowances.

Table A3.6 Trading and Banking Rules in the MARAMA Base Case

	Title IV SO_2	**CAIR Annual NO_x**	**CAIR Ozone Season NO_x**	**CAVR Rule – SO_2**	**CAVR Rule – NO_x**	**CAMR (Clean Air Mercury Rule)**
Coverage	All Fossil units >25 MW	All Fossil units >25 MW *	All Fossil units >25 MW **	All Coal, CAVR Eligible, Non CAIR Unscrubbed and Non WRAP > 200 MW ***	All Coal & CAVR Eligible Outside CAIR > 200 MW	All Coal Units > 25 MW
Timing	Annual	Annual	Ozone Season (May – September)	Annual	Annual	Annual
Size of Initial Bank	6,437 thousand tons starting in 2007	The bank starting in 2009 is assumed to be zero.	The bank starting in 2007 is assumed to be zero.	N/A	N/A	-
Policy Structure	Trading and Banking allowed	Trading and Banking allowed	Trading and Banking allowed	No Trading or banking	No Trading or banking	Trading and Banking allowed
Rules						
Total Allowances (thousand tons except for CAMR is in tons)	2007-2009: 9,470 2010-2030: 8,950	2009: 1,722 2010-2014: 1,522 2015-2030: 1,268	2007-2008: 497[1] 2009-2014: 568 2015-2030: 485	N/A	N/A	2010-2017: 38 2018-2030: 15
Total Allowances Pre 2007 Bank Less NSR and North Carolina SO_2 Allowance Retirements (thousand tons)	2007: 15,805 2008: 9,350 2009: 9,280 2010-2012: 8,813 2013-2030: 8,611	2009: 1,722 2010-2014: 1,522 2015-2030: 1,268	2007-2008: 497[1] 2009-2014: 568 2015-2030: 485	N/A	N/A	2010-2017: 38 2018-2030: 15
Non Cap and Trade Policy Specifications	N/A	N/A	N/A	0.15 lbs/MMBtu	Combustion Controls on units >200MW and SCRs on cyclone fired units	N/A
Retirement Ratio	2010: 2.0 2012: 2.0 2015: 2.52 2018: 2.86	2009-2030: 1.0	2007-2030: 1.0	N/A	N/A	2007-2030: 1.0

* **CAIR Region States**: Alabama, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, New Jersey, Delaware.

** **CAIR Ozone Season States**: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin.

*** **WRAP States**: Arizona, New Mexico, Oregon, Utah, Wyoming

1. SIP Call

Table A3.7 Trading and Banking Rules in the MARAMA Policy Case

	Title IV SO_2	MARAMA CAIR Plus - Annual NO_x	MARAMA SIP Call and CAIR Plus - Ozone season NO_x	CAVR Rule – SO_2	CAVR Rule – NO_x	CAMR (Clean Air Mercury Rule)
Coverage	All Fossil units >25 MW	All Fossil units >25 MW *	All Fossil units >25 MW **	All Coal, CAVR Eligible, Non CAIR Unscrubbed and Non WRAP > 200 MW ***	All Coal & CAVR Eligible Outside CAIR > 200 MW	All Coal Units > 25 MW
Timing	Annual	Annual	Ozone Season (May – September)	Annual	Annual	Annual
Size of Initial Bank	6,437 thousand tons starting in 2007	The bank starting in 2009 is assumed to be zero.	The bank starting in 2007 is assumed to be zero.	N/A	N/A	-
Policy Structure	Trading and Banking allowed	Trading and Banking allowed	Trading and Banking allowed	No Trading or banking	No Trading or banking	Trading and Banking allowed
Rules						
Total Allowances (thousand tons except for CAMR is in Tons)	2007-2009: 9,470 2010-2030: 8,950	2009: 1,553 2010-2011: 1,353 2012-2014: 902 2015-2030: 829	2007-2008: 497[1] 2009-2011: 623 2012-2014: 416 2015-2030: 382	N/A	N/A	2010-2017: 38 2018-2030: 15
Total Allowances Pre 2007 Bank Less NSR and North Carolina SO_2 Allowance Retirements (thousand tons)	2007: 15,805 2008: 9,350 2009: 9,280 2010-2012: 8,813 2013-2030: 8,611	2009: 1,553 2010-2011: 1,353 2012-2014: 902 2015-2030: 829	2007-2008: 497[1] 2009-2011: 623 2012-2014: 416 2015-2030: 382	N/A	N/A	2010-2017: 38 2018-2030: 15
Non Cap and Trade Policy Specifications	N/A	N/A	N/A	0.15 lbs/MMBtu	Combustion Controls on units >200MW and SCRs on cyclone fired units	N/A
Retirement Ratio	2010: 2.5 2012: 2.94 2015: 3.32 2018: 4.16	2009-2030: 1.0	2007-2030: 1.0	N/A	N/A	2007-2030: 1.0

* **CAIR Plus Policy States**: Alabama, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New Jersey, Delaware, Arkansas.

** **CAIR Ozone Season States**: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin.

*** **WRAP States**: Arizona, New Mexico, Oregon, Utah, Wyoming

1. SIP Call

Appendix 4: Comparison of Assumptions Used in VISTAS and MARAMA analysis

Table 4.1 Differences in assumptions between the VISTAS and MARAMA projects.

Parameter	VISTAS	MARAMA
Run Years	2007,2010,2015,2020,2026	2008,2009, 2010,2012,2015,2018,2020,2026
Gas Supply Curve	EPA Base Case v.2.19 (see table below)	EPA Base Case v.3.0 (refer to table A3.2 in Appendix 3.)
Fuel Oil Prices	AEO 2004 (See table below)	AEO 2006 (Refer to table A3.3 in Appendix 3)
SCR and Scrubber Feasibility Limits	No limits applied in 2008, 2009 and 2010	Limits applied in 2008, 2009 and 2010. (Refer to table A3.4 in Appendix 3)
Clean Air Visibility Rule	Not modeled	Implemented the CAVR rule for SO_2 and NO_X
Title IV SO_2 Bank (2007)	4.98 million tons	6.43 million tons

Table A4.2: Natural Gas Supply Curve Used in VISTAS Run

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2007	2.75	19411	23560	4149
2007	2.80	19314	23580	4266
2007	2.85	19220	23600	4380
2007	2.90	19128	23620	4492
2007	2.95	19038	23640	4602
2007	3.00	18950	23660	4710
2007	3.05	18863	23680	4817
2007	3.10	18778	23700	4922
2007	3.15	18695	23720	5025
2007	3.20	18614	23730	5116
2007	3.25	18534	23740	5206
2007	3.26	18514	23740	5226
2007	3.30	18457	23790	5333
2007	3.35	18378	23800	5422
2007	3.40	18299	23810	5511
2007	3.44	18243	23820	5577
2007	3.45	18224	23820	5596
2007	3.50	18157	23830	5673
2007	3.55	18090	23840	5750
2007	3.57	18066	23840	5774
2007	3.60	18021	23850	5829
2007	3.65	17952	23860	5908
2007	3.70	17884	23870	5986
2007	3.75	17818	23880	6062
2007	3.80	17753	23890	6137
2007	3.85	17689	23900	6211
2007	3.90	17626	23910	6284
2007	3.95	17564	23920	6356
2007	4.00	17503	23930	6427
2007	4.05	17443	23940	6497
2007	4.10	17384	23950	6566
2007	4.15	17326	23960	6634
2007	4.20	17269	23970	6701
2007	4.25	17212	23980	6768
2007	4.30	17156	23990	6834
2007	4.35	17101	24000	6899
2007	4.40	17047	24010	6963
2007	4.45	16994	24020	7026
2007	4.50	16941	24030	7089
2007	4.55	16889	24040	7151
2007	4.60	16838	24050	7212
2007	4.65	16788	24060	7272
2007	4.70	16738	24070	7332
2007	4.75	16689	24080	7391
2007	4.80	16641	24090	7449
2007	4.85	16593	24100	7507
2007	4.90	16546	24110	7564
2007	4.95	16500	24120	7620

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2007	5.00	16454	24130	7676
2007	5.05	16409	24140	7731
2007	5.10	16364	24150	7786
2007	5.15	16320	24160	7840
2007	5.20	16276	24170	7894
2007	5.25	16233	24180	7947
2007	5.30	16190	24190	8000
2007	5.35	16148	24200	8052
2007	5.40	16106	24210	8104
2007	5.41	16064	24220	8156
2010	2.75	19727	23780	4053
2010	2.80	19621	23890	4269
2010	2.85	19517	23990	4473
2010	2.90	19415	24090	4675
2010	2.95	19316	24190	4874
2010	3.00	19219	24290	5071
2010	3.05	19124	24390	5266
2010	3.10	19031	24490	5459
2010	3.15	18940	24590	5650
2010	3.16	18916	24620	5704
2010	3.20	18856	24850	5994
2010	3.25	18766	24970	6204
2010	3.29	18691	25070	6379
2010	3.30	18678	25080	6402
2010	3.35	18597	25130	6533
2010	3.40	18516	25180	6664
2010	3.45	18435	25230	6795
2010	3.46	18411	25240	6829
2010	3.50	18355	25300	6945
2010	3.55	18277	25390	7113
2010	3.60	18200	25480	7280
2010	3.65	18125	25570	7445
2010	3.70	18051	25660	7609
2010	3.75	17978	25740	7762
2010	3.80	17907	25820	7913
2010	3.85	17837	25900	8063
2010	3.90	17768	25980	8212
2010	3.95	17700	26060	8360
2010	4.00	17633	26140	8507
2010	4.05	17567	26220	8653
2010	4.10	17502	26300	8798
2010	4.15	17438	26380	8942
2010	4.20	17375	26460	9085
2010	4.25	17313	26540	9227
2010	4.30	17252	26620	9368
2010	4.35	17192	26700	9508
2010	4.40	17133	26770	9637
2010	4.45	17075	26840	9765
2010	4.50	17018	26910	9892
2010	4.55	16962	26980	10018

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2010	4.60	16906	27050	10144
2010	4.65	16851	27120	10269
2010	4.70	16797	27190	10393
2010	4.75	16744	27260	10516
2010	4.80	16691	27330	10639
2010	4.85	16639	27400	10761
2010	4.90	16588	27470	10882
2010	4.95	16538	27540	11002
2010	5.00	16488	27610	11122
2010	5.05	16439	27680	11241
2010	5.10	16390	27750	11360
2010	5.15	16342	27820	11478
2010	5.20	16295	27890	11595
2010	5.25	16248	27960	11712
2010	5.30	16202	28020	11818
2010	5.35	16156	28080	11924
2010	5.40	16111	28140	12029
2010	5.41	16066	28200	12134
2015	2.75	20148	24960	4812
2015	2.80	20060	25140	5080
2015	2.85	19974	25320	5346
2015	2.90	19890	25500	5610
2015	2.95	19808	25670	5862
2015	3.00	19727	25840	6113
2015	3.05	19648	26010	6362
2015	3.08	19599	26120	6521
2015	3.10	19569	26210	6641
2015	3.15	19489	26460	6971
2015	3.18	19442	26610	7168
2015	3.20	19413	26680	7267
2015	3.25	19343	26850	7507
2015	3.30	19273	27020	7747
2015	3.35	19203	27190	7987
2015	3.39	19144	27330	8186
2015	3.40	19134	27350	8216
2015	3.45	19069	27480	8411
2015	3.50	19004	27610	8606
2015	3.55	18939	27740	8801
2015	3.60	18874	27870	8996
2015	3.65	18809	28000	9191
2015	3.70	18744	28130	9386
2015	3.70	18741	28140	9399
2015	3.75	18683	28280	9597
2015	3.80	18623	28430	9807
2015	3.85	18564	28580	10016
2015	3.90	18506	28730	10224
2015	3.95	18449	28880	10431
2015	4.00	18393	29020	10627
2015	4.05	18338	29160	10822
2015	4.10	18283	29300	11017

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2015	4.15	18229	29440	11211
2015	4.20	18176	29580	11404
2015	4.25	18124	29720	11596
2015	4.30	18073	29860	11787
2015	4.35	18022	30000	11978
2015	4.40	17972	30140	12168
2015	4.45	17923	30280	12357
2015	4.50	17874	30410	12536
2015	4.55	17826	30540	12714
2015	4.60	17779	30670	12891
2015	4.65	17732	30800	13068
2015	4.70	17686	30930	13244
2015	4.75	17641	31060	13419
2015	4.80	17596	31190	13594
2015	4.85	17552	31320	13768
2015	4.90	17508	31450	13942
2015	4.95	17465	31580	14115
2015	5.00	17422	31710	14288
2015	5.05	17380	31840	14460
2015	5.10	17338	31960	14622
2015	5.15	17297	32080	14783
2015	5.20	17256	32200	14944
2015	5.25	17216	32320	15104
2015	5.30	17176	32440	15264
2015	5.35	17137	32560	15423
2015	5.40	17098	32680	15582
2020	2.75	20782	27560	6778
2020	2.80	20695	27720	7025
2020	2.85	20610	27870	7260
2020	2.90	20527	28020	7493
2020	2.95	20449	28160	7711
2020	2.95	20445	28170	7725
2020	3.00	20369	28320	7951
2020	3.05	20293	28470	8177
2020	3.10	20217	28620	8403
2020	3.15	20141	28770	8629
2020	3.20	20065	28920	8855
2020	3.25	19989	29070	9081
2020	3.29	19935	29180	9245
2020	3.30	19914	29230	9316
2020	3.35	19844	29400	9556
2020	3.40	19774	29570	9796
2020	3.45	19704	29740	10036
2020	3.49	19646	29880	10234
2020	3.50	19636	29900	10264
2020	3.55	19577	30010	10433
2020	3.60	19518	30120	10602
2020	3.65	19459	30230	10771
2020	3.70	19400	30340	10940
2020	3.75	19341	30450	11109

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2020	3.80	19282	30560	11278
2020	3.85	19223	30670	11447
2020	3.90	19164	30780	11616
2020	3.95	19105	30890	11785
2020	4.00	19046	31000	11954
2020	4.02	19024	31040	12016
2020	4.05	18990	31120	12130
2020	4.10	18936	31240	12304
2020	4.15	18883	31360	12477
2020	4.20	18830	31480	12650
2020	4.25	18778	31600	12822
2020	4.30	18727	31720	12993
2020	4.35	18677	31840	13163
2020	4.40	18627	31950	13323
2020	4.45	18578	32060	13482
2020	4.50	18530	32170	13640
2020	4.55	18482	32280	13798
2020	4.60	18435	32390	13955
2020	4.65	18389	32500	14111
2020	4.70	18343	32610	14267
2020	4.75	18298	32720	14422
2020	4.80	18253	32830	14577
2020	4.85	18209	32940	14731
2020	4.90	18165	33050	14885
2020	4.95	18122	33160	15038
2020	5.00	18080	33270	15190
2020	5.05	18038	33370	15332
2020	5.10	17997	33470	15473
2020	5.15	17956	33570	15614
2020	5.20	17916	33670	15754
2020	5.25	17876	33770	15894
2020	5.30	17837	33870	16033
2020	5.35	17798	33970	16172
2020	5.40	17759	34070	16311

Table A4.3: Fuel Oil Prices Used in VISTAS Run

High Sulfur Residual Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	MACE	New England
2007	3.51	2.93
2010	3.57	2.98
2015	3.67	3.11
2020	3.76	3.22
Source: AEO 2004		

Low Sulfur Residual Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	MACE	New England
2007	3.73	3.30
2010	3.79	3.35
2015	3.90	3.47
2020	3.99	3.58
Source: AEO 2004		

Distillate Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	MACE	New England
2007	4.72	4.80
2010	4.86	4.94
2015	5.23	5.29
2020	5.58	5.60
Source: AEO 2004		

Appendix 5: Emission and Cost Results

Tables A5.1- A5.3 present SO_2 and NO_x emissions from the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs by state in 2008, 2009, 2012, 2015 and 2018 run years. These emissions are from all units and include emissions from fossil and non-fossil units

Tables A5.4- A5.8 present variable O&M costs, fixed O&M costs, annualized capital costs, fuel costs and total production costs from the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs by state in 2008, 2009, 2012, 2015 and 2018 run years.

Table A5.1: State Level Annual SO_2 Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	3.92	3.97	9.93	12.18	14.71	3.02	3.07	4.29	4.94	5.01	-0.90	-0.90	-5.65	-7.24	-9.70
	Delaware	33.74	32.55	17.58	15.39	14.43	33.74	29.61	28.25	8.08	3.33	0.00	-2.93	10.67	-7.31	-11.09
	District of Columbia	0.00	0.00	0.19	0.29	0.63	0.00	0.00	0.41	0.49	0.69	0.00	0.00	0.22	0.20	0.05
	Maine	38.00	38.37	8.27	8.99	9.87	34.72	33.00	5.23	5.16	4.89	-3.27	-5.37	-3.04	-3.82	-4.98
	Maryland	130.21	65.67	52.98	31.47	35.48	100.07	39.07	33.04	31.42	32.81	-30.13	-26.60	-19.94	-0.04	-2.67
	Massachusetts	78.18	36.10	29.38	29.53	33.89	74.98	37.13	15.75	11.47	8.96	-3.19	1.03	-13.62	-18.05	-24.93
	New Hampshire	7.66	7.66	11.88	13.38	15.17	7.66	4.97	3.38	3.17	3.27	0.00	-2.68	-8.50	-10.21	-11.90
	New Jersey	26.56	25.85	28.02	26.43	23.32	26.23	25.89	26.67	23.82	16.93	-0.34	0.04	-1.35	-2.61	-6.39
	New York	124.38	121.50	102.95	90.74	85.54	110.99	105.26	76.55	72.32	66.51	-13.39	-16.24	-26.40	-18.42	-19.03
	Pennsylvania	359.35	318.52	199.42	179.15	156.97	343.13	277.39	182.70	150.27	127.58	-16.22	-41.13	-16.72	-28.88	-29.39
	Rhode Island	0.00	0.00	1.29	1.77	2.32	0.00	0.00	0.26	0.40	0.42	0.00	0.00	-1.02	-1.37	-1.90
	Vermont	0.06	0.06	0.87	1.16	1.51	0.06	0.06	0.22	0.31	0.32	0.00	0.00	-0.65	-0.86	-1.19
MANE-VU Total		802.06	650.24	462.75	410.48	393.84	734.60	555.46	376.75	311.86	270.72	-67.45	-94.78	-86.00	-98.62	-123.12
LADCO	Illinois	304.36	305.10	260.79	242.83	244.94	299.78	274.23	240.60	222.03	238.38	-4.59	-30.87	-20.19	-20.80	-6.57
	Indiana	496.08	483.36	463.56	414.50	376.78	476.80	410.99	409.93	377.38	332.21	-19.28	-72.38	-53.63	-37.11	-44.57
	Michigan	407.01	407.02	398.16	397.45	399.56	406.35	390.37	397.12	391.05	376.77	-0.66	-16.64	-1.04	-6.40	-22.79
	Ohio	581.77	440.10	317.26	282.43	264.40	431.30	436.33	249.67	194.09	184.86	-150.46	-3.77	-67.58	-88.34	-79.54
	Wisconsin	161.24	149.57	153.59	153.31	152.02	161.30	148.40	150.63	148.06	142.94	0.06	-1.17	-2.96	-5.25	-9.09
LADCO Total		1,950.46	1,785.15	1,593.35	1,490.51	1,437.70	1,775.52	1,660.32	1,447.95	1,332.62	1,275.15	-174.93	-124.83	-145.40	-157.89	-162.56
VISTAS	Alabama	357.18	332.19	286.09	253.71	217.58	336.53	264.83	219.62	185.76	158.36	-20.65	-67.36	-66.47	-67.96	-59.22
	Florida	213.04	210.85	194.80	194.07	165.00	212.81	190.25	157.71	156.67	115.33	-0.22	-20.60	-37.09	-37.40	-49.67
	Georgia	558.02	560.12	312.67	214.82	183.00	573.16	371.67	92.72	94.53	74.99	15.14	-188.45	-219.95	-120.29	-108.01
	Kentucky	386.28	376.19	274.92	274.02	239.92	362.81	328.20	274.84	223.64	203.38	-23.47	-47.99	-0.08	-50.39	-36.54
	Mississippi	82.21	70.23	85.73	27.87	23.15	81.55	62.58	25.44	23.13	24.60	-0.66	-7.65	-60.29	-4.75	1.44
	North Carolina	261.33	167.47	130.55	110.64	101.45	260.58	146.20	121.39	92.23	73.64	-0.74	-21.27	-9.15	-18.41	-27.81
	South Carolina	184.15	171.26	119.43	115.66	114.30	162.00	138.43	119.59	91.30	63.08	-22.15	-32.83	0.16	-24.37	-51.21
	Tennessee	246.52	244.39	235.35	231.69	141.52	237.50	168.68	197.69	136.09	109.20	-9.03	-75.71	-37.66	-95.60	-32.32
	Virginia	200.04	178.64	146.24	117.17	81.50	180.42	156.77	126.48	71.27	46.67	-19.62	-21.88	-19.76	-45.90	-34.84
	West Virginia	390.89	390.67	195.44	150.00	130.75	289.42	221.84	126.03	115.98	122.55	-101.46	-168.83	-69.41	-34.02	-8.20
VISTAS Total		2,879.64	2,702.01	1,981.22	1,689.66	1,398.18	2,696.77	2,049.45	1,461.51	1,190.59	991.81	-182.87	-652.56	-519.71	-499.07	-406.38
CENRAP	Arkansas	82.63	82.63	83.25	40.83	42.15	82.63	81.80	83.30	37.71	40.29	0.00	-0.82	0.05	-3.12	-1.87
	Iowa	145.10	139.66	147.98	143.60	144.93	146.70	130.53	140.02	138.56	137.16	1.60	-9.13	-7.96	-5.04	-7.76
	Kansas	80.16	80.52	81.49	59.32	59.32	78.46	78.82	81.49	59.33	59.35	-1.70	-1.70	0.00	0.01	0.03
	Louisiana	111..31	111..31	75.49	77.24	79.60	111..31	91.70	75.59	77.31	76.61	0.00	-19.61	0.10	0.07	-2.99

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	96.56	87.90	86.82	85.30	84.26	95.74	84.24	83.05	69.59	65.86	-0.82	-3.66	-3.76	-15.70	-18.39
	Missouri	266.99	276.53	280.25	279.80	279.97	264.07	248.11	273.51	266.06	224.45	-2.93	-28.42	-6.75	-13.74	-55.53
	Nebraska	73.63	73.63	73.63	37.18	37.18	73.63	73.63	73.63	37.18	37.18	0.00	0.00	0.00	0.00	0.00
	Oklahoma	113.68	113.68	117.28	48.06	50.15	113.68	113.68	119.44	48.08	52.18	0.00	0.00	2.17	0.02	2.03
	Texas	425.27	425.27	439.21	387.56	359.20	424.27	422.47	384.06	280.92	268.72	-1.00	-2.80	-55.15	-106.63	-90.48
CENRAP Total		1,395.34	1,391.13	1,385.39	1,158.90	1,136.76	1,390.49	1,324.98	1,314.08	1,014.75	961.80	-4.85	-66.15	-71.31	-144.15	-174.96
WRAP	Arizona	60.54	60.55	63.28	63.28	56.83	60.54	60.55	63.80	64.22	57.78	0.00	0.00	0.52	0.95	0.96
	California	6.79	6.79	7.53	7.53	7.45	6.79	6.67	7.63	7.63	7.49	0.00	-0.12	0.10	0.10	0.04
	Colorado	87.22	86.55	87.21	52.84	53.62	86.55	86.56	87.21	52.84	53.75	-0.67	0.01	0.00	0.00	0.14
	Idaho	0.05	0.05	1.14	1.14	1.01	0.05	0.05	1.28	1.28	1.08	0.00	0.00	0.14	0.14	0.07
	Montana	19.88	19.88	20.51	20.51	20.46	16.72	16.72	20.60	20.60	20.50	-3.16	-3.16	0.08	0.08	0.04
	Nevada	31.24	31.30	31.96	28.21	29.00	31.24	31.30	32.10	28.44	29.23	0.00	0.00	0.15	0.24	0.23
	New Mexico	52.92	52.92	53.64	53.64	54.42	52.92	52.92	53.77	53.85	54.63	0.00	0.00	0.13	0.21	0.20
	North Dakota	92.63	92.65	93.39	85.04	85.05	96.70	100.00	109.45	101.11	101.91	4.07	7.35	16.06	16.07	16.86
	Oregon	10.18	10.18	16.27	16.27	15.54	10.18	10.18	17.07	17.07	15.91	0.00	0.00	0.79	0.79	0.37
	South Dakota	12.09	12.09	12.09	4.15	4.20	12.09	12.09	12.09	4.18	4.20	0.00	0.00	0.00	0.03	0.00
	Utah	53.16	53.16	53.16	53.16	33.55	53.16	53.16	53.16	53.16	33.55	0.00	0.00	0.00	0.00	0.00
	Washington	11.25	11.25	20.75	20.68	19.29	11.25	11.25	22.18	20.96	22.06	0.00	0.00	1.44	0.28	2.76
	Wyoming	70.13	70.10	72.69	71.37	38.69	64.79	64.64	71.95	72.45	38.72	-5.35	-5.46	-0.74	1.08	0.02
WRAP Total		508.08	507.48	533.62	477.82	419.10	502.97	506.09	552.29	497.79	440.80	-5.11	-1.39	18.67	19.97	21.70
CAIR Plus Policy States		6,760.02	6,260.69	5,150.31	4,604.99	4,219.83	6,331.62	5,324.07	4,325.72	3,705.23	3,350.76	-428.40	-936.62	-824.59	-899.76	-869.07
National		7,535.57	7,036.00	5,956.32	5,227.37	4,785.59	7,100.36	6,096.28	5,152.57	4,347.61	3,940.28	-435.21	-939.72	-803.75	-879.77	-845.31

Table A5.2: State Level Annual NO_x Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	3.45	3.60	5.07	5.19	5.69	3.42	3.74	3.64	3.81	3.86	-0.03	0.15	-1.43	-1.38	-1.83
	Delaware	12.51	10.72	11.40	10.91	10.72	12.52	10.16	9.68	4.84	3.88	0.01	-0.56	-1.72	-6.07	-6.83
	District of Columbia	0.11	0.13	0.21	0.30	0.48	0.11	0.13	0.33	0.39	0.50	0.00	0.00	0.12	0.10	0.02
	Maine	7.80	7.94	2.66	2.64	2.78	7.42	3.25	1.87	1.89	1.86	-0.38	-4.69	-0.79	-0.75	-0.92
	Maryland	54.68	16.33	16.10	16.76	19.22	54.68	14.38	17.36	17.54	18.73	0.00	-1.96	1.26	0.79	-0.49
	Massachusetts	30.40	24.25	24.57	22.05	22.55	20.90	13.89	12.03	9.89	9.96	-9.49	-10.37	-12.54	-12.16	-12.59
	New Hampshire	3.96	4.07	5.32	5.28	5.65	3.96	2.92	2.45	2.56	2.66	0.00	-1.15	-2.87	-2.72	-2.99
	New Jersey	16.90	10.82	11.00	12.70	12.54	16.88	11.57	10.64	12.06	10.89	-0.02	0.75	-0.36	-0.65	-1.64
	New York	48.33	48.42	46.14	41.52	38.72	47.59	41.00	31.26	30.61	28.72	-0.74	-7.42	-14.88	-10.91	-9.99
	Pennsylvania	207.46	144.89	85.35	83.95	79.34	208.06	126.22	72.38	68.60	64.08	0.60	-18.66	-12.98	-15.35	-15.26
	Rhode Island	0.26	0.59	0.53	0.57	0.67	0.26	0.58	0.23	0.27	0.27	0.00	-0.01	-0.30	-0.30	-0.40
	Vermont	0.13	0.17	0.39	0.40	0.47	0.13	0.16	0.19	0.21	0.23	0.00	0.00	-0.20	-0.18	-0.24
MANE-VU Total		385.99	271.92	208.74	202.25	198.82	375.92	228.00	162.05	152.67	145.64	-10.06	-43.92	-46.69	-49.58	-53.18
LADCO	Illinois	131.60	87.21	73.57	70.99	72.80	130.94	62.34	56.53	54.12	53.33	-0.66	-24.87	-17.03	-16.87	-19.46
	Indiana	219.40	144.58	107.85	96.96	85.08	221.73	136.98	54.83	53.22	51.32	2.33	-7.60	-53.02	-43.74	-33.76
	Michigan	120.64	86.96	85.53	87.16	92.62	120.00	82.48	39.77	40.44	41.42	-0.64	-4.48	-45.76	-46.72	-51.21
	Ohio	272.07	116.53	97.31	89.00	85.95	271.91	101.79	66.96	65.25	63.56	-0.16	-14.75	-30.35	-23.75	-22.39
	Wisconsin	60.14	48.14	44.77	45.39	45.66	59.63	42.34	31.15	31.70	32.17	-0.51	-5.80	-13.63	-13.69	-13.49
LADCO Total		803.86	483.42	409.04	389.50	382.12	804.22	425.92	249.25	244.74	241.79	0.36	-57.50	-159.79	-144.77	-140.32
VISTAS	Alabama	131.82	82.73	68.84	47.15	47.46	134.12	52.64	31.69	31.13	32.74	2.30	-30.10	-37.15	-16.02	-14.72
	Florida	164.71	115.54	78.29	74.45	66.66	164.71	105.40	49.61	49.19	48.58	0.00	-10.13	-28.68	-25.25	-18.07
	Georgia	239.40	96.35	91.57	59.66	51.41	239.40	74.34	37.81	38.67	42.01	0.00	-22.01	-53.76	-20.99	-9.40
	Kentucky	171.39	96.49	88.06	70.17	58.75	176.12	97.11	38.57	37.75	37.35	4.73	0.62	-49.49	-32.42	-21.40
	Mississippi	38.10	31.42	31.53	8.19	9.06	38.10	29.14	7.67	8.53	9.64	0.00	-2.29	-23.87	0.34	0.58
	North Carolina	62.68	55.96	56.86	56.91	56.57	62.71	52.14	52.66	51.01	49.03	0.03	-3.82	-4.19	-5.90	-7.54
	South Carolina	50.92	35.94	39.26	38.95	40.67	52.51	37.72	27.56	27.14	29.35	1.58	1.78	-11.70	-11.81	-11.31
	Tennessee	104.12	48.39	39.34	39.14	29.16	104.92	28.22	20.27	20.23	20.28	0.80	-20.17	-19.07	-18.91	-8.89
	Virginia	65.86	61.62	55.49	48.35	39.70	65.11	56.29	35.25	33.27	31.77	-0.74	-5.34	-20.25	-15.08	-7.93
	West Virginia	178.66	75.42	71.84	59.08	53.44	177.99	64.59	50.12	49.30	49.51	-0.66	-10.83	-21.72	-9.78	-3.93
VISTAS Total		1,207.64	699.87	621.10	502.04	452.87	1,215.69	597.58	351.22	346.21	350.26	8.05	-102.29	-269.88	-155.83	-102.62
CENRAP	Arkansas	45.27	32.09	33.00	34.03	35.42	45.27	32.47	16.46	12.16	13.69	0.01	0.38	-16.54	-21.87	-21.73
	Iowa	74.73	46.67	50.84	47.85	48.69	75.86	41.36	20.33	20.31	19.64	1.14	-5.31	-30.50	-27.54	-29.06
	Kansas	82.69	82.77	82.84	53.35	53.55	82.69	83.10	82.87	53.38	53.55	0.00	0.33	0.03	0.03	0.00
	Louisiana	50.66	31.88	33.58	32.36	34.75	50.79	31.59	14.73	15.69	17.95	0.13	-0.28	-18.85	-16.67	-16.81

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	74.90	41.18	40.77	40.40	40.52	74.85	36.54	18.58	17.40	16.71	-0.05	-4.64	-22.20	-23.01	-23.81
	Missouri	121.35	72.43	74.57	67.79	67.90	121.95	67.82	49.68	48.50	45.56	0.60	-4.61	-24.89	-19.30	-22.34
	Nebraska	50.75	50.77	50.77	38.47	38.57	50.82	50.86	50.85	38.56	38.58	0.08	0.08	0.08	0.09	0.01
	Oklahoma	74.02	78.23	77.50	53.42	53.52	73.94	80.88	77.80	56.21	55.85	-0.08	2.64	0.30	2.79	2.33
	Texas	180.11	168.10	172.16	171.74	165.40	178.34	152.86	100.30	99.43	90.16	-1.77	-15.24	-71.86	-72.32	-75.24
CENRAP Total		754.46	604.11	616.04	539.42	538.33	754.51	577.47	431.60	361.63	351.69	0.05	-26.64	-184.44	-177.79	-186.64
WRAP	Arizona	79.45	79.51	82.42	67.94	71.85	79.46	79.50	82.92	68.46	72.74	0.01	-0.01	0.50	0.52	0.89
	California	30.21	33.26	26.83	28.51	31.66	30.18	33.44	26.49	28.19	31.04	-0.03	0.18	-0.34	-0.32	-0.62
	Colorado	68.06	68.82	68.90	60.47	61.54	68.05	68.89	68.94	60.43	61.47	0.00	0.06	0.04	-0.03	-0.06
	Idaho	0.71	0.71	0.79	0.79	0.79	0.71	0.71	0.87	0.87	0.87	0.00	0.00	0.08	0.08	0.08
	Montana	38.43	38.43	38.79	38.79	38.81	38.43	38.44	38.84	38.84	38.86	0.00	0.01	0.05	0.05	0.05
	Nevada	46.56	46.66	47.08	30.70	31.59	46.56	46.80	47.22	30.83	31.84	0.00	0.15	0.13	0.13	0.26
	New Mexico	73.49	73.64	74.31	72.30	73.16	73.49	73.68	74.47	72.55	73.46	0.00	0.04	0.17	0.25	0.30
	North Dakota	71.54	71.71	71.69	39.86	39.93	70.92	71.76	71.76	39.94	39.94	-0.61	0.05	0.07	0.09	0.02
	Oregon	10.84	10.84	14.27	14.27	14.27	10.84	10.84	14.72	14.72	14.72	0.00	0.00	0.45	0.45	0.45
	South Dakota	14.54	14.54	14.55	1.75	1.82	14.57	14.58	14.58	1.80	1.82	0.03	0.04	0.03	0.05	0.00
	Utah	60.79	60.79	60.79	53.39	53.36	60.79	60.79	60.79	53.39	53.36	0.00	0.00	0.00	0.00	0.00
	Washington	25.34	26.23	31.95	21.54	21.54	25.34	25.90	32.42	22.40	22.40	0.00	-0.33	0.47	0.86	0.86
	Wyoming	81.17	81.17	81.18	53.07	53.17	81.18	81.18	81.18	53.07	53.19	0.01	0.01	0.01	0.00	0.01
WRAP Total		601.11	606.30	613.54	483.37	493.48	600.52	606.50	615.20	485.50	495.72	-0.60	0.20	1.66	2.13	2.24
CAIR Plus Policy States		2,944.50	1,847.55	1,643.80	1,487.96	1,426.50	2,942.89	1,614.14	982.59	957.10	941.40	-1.61	-233.41	-661.20	-530.87	-485.10
National		3,753.06	2,665.62	2,468.46	2,116.58	2,065.62	3,750.86	2,435.47	1,809.32	1,590.75	1,585.10	-2.20	-230.15	-659.14	-525.84	-480.52

Table A5.3: State Level Ozone Season NO_x Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	1.55	1.62	2.20	2.25	2.47	1.54	1.68	1.60	1.66	1.69	0.00	0.06	-0.60	-0.59	-0.78
	Delaware	4.63	4.20	4.98	4.51	4.38	4.64	4.12	3.91	1.96	1.64	0.01	-0.08	-1.07	-2.55	-2.74
	District of Columbia	0.05	0.08	0.09	0.12	0.20	0.05	0.08	0.14	0.17	0.21	0.00	0.00	0.05	0.04	0.01
	Maine	3.59	3.55	1.14	1.13	1.16	3.49	1.31	0.79	0.80	0.81	-0.10	-2.24	-0.34	-0.32	-0.35
	Maryland	12.69	7.18	7.40	7.42	8.59	12.69	6.56	7.84	7.72	8.29	0.00	-0.62	0.43	0.30	-0.30
	Massachusetts	10.68	9.47	10.62	9.07	9.37	6.38	5.60	5.11	4.25	4.16	-4.31	-3.87	-5.51	-4.83	-5.21
	New Hampshire	1.75	1.82	2.32	2.30	2.46	1.75	1.03	1.07	1.08	1.15	0.00	-0.79	-1.25	-1.23	-1.31
	New Jersey	4.67	4.84	4.88	5.70	5.59	4.67	5.25	4.85	5.31	5.10	0.00	0.41	-0.04	-0.39	-0.49
	New York	19.58	19.11	21.09	18.58	17.43	19.27	17.10	14.37	13.68	12.49	-0.31	-2.00	-6.72	-4.91	-4.93
	Pennsylvania	62.25	57.36	36.82	36.24	34.25	62.83	43.56	30.97	29.61	28.35	0.58	-13.80	-5.85	-6.63	-5.89
	Rhode Island	0.16	0.27	0.23	0.24	0.29	0.16	0.27	0.10	0.11	0.12	0.00	-0.01	-0.13	-0.13	-0.17
	Vermont	0.06	0.10	0.17	0.17	0.20	0.06	0.10	0.09	0.09	0.10	0.00	0.00	-0.08	-0.08	-0.10
MANE-VU Total		121.67	109.58	91.93	87.75	86.38	117.54	86.66	70.83	66.43	64.11	-4.13	-22.92	-21.10	-21.32	-22.27
LADCO	Illinois	30.31	28.33	32.45	31.95	31.69	29.03	26.58	24.94	24.00	23.26	-1.28	-1.75	-7.51	-7.95	-8.44
	Indiana	61.31	60.02	46.53	41.46	36.50	63.58	54.08	23.69	23.16	22.42	2.27	-5.93	-22.83	-18.30	-14.09
	Michigan	36.78	36.92	36.29	36.73	38.88	35.96	33.31	16.79	17.24	17.72	-0.82	-3.62	-19.50	-19.49	-21.16
	Ohio	48.38	42.32	41.24	37.73	36.63	49.00	40.18	28.70	28.03	27.74	0.62	-2.13	-12.55	-9.70	-8.88
	Wisconsin	26.45	18.68	19.11	19.68	19.74	26.31	18.10	13.33	13.57	13.92	-0.14	-0.57	-5.77	-6.10	-5.82
LADCO Total		203.23	186.27	175.61	167.55	163.44	203.88	172.26	107.46	106.01	105.05	0.65	-14.01	-68.16	-61.54	-58.39
VISTAS	Alabama	33.72	30.51	30.95	20.94	21.00	36.02	20.24	14.30	14.22	14.73	2.30	-10.27	-16.65	-6.72	-6.27
	Florida	76.17	53.00	36.71	34.10	30.75	76.17	44.39	24.18	22.93	23.06	0.00	-8.61	-12.53	-11.16	-7.68
	Georgia	106.58	43.62	41.36	26.77	23.56	106.58	30.03	17.10	17.48	18.91	0.00	-13.59	-24.26	-9.30	-4.65
	Kentucky	41.98	39.49	38.10	30.09	25.80	46.68	36.23	16.90	16.59	16.52	4.70	-3.26	-21.20	-13.50	-9.28
	Mississippi	17.34	11.93	14.27	3.97	4.33	17.34	11.75	3.70	4.10	4.59	0.00	-0.17	-10.56	0.13	0.26
	North Carolina	21.62	14.73	21.91	24.26	25.43	21.65	18.17	20.95	21.97	21.30	0.03	3.43	-0.96	-2.29	-4.12
	South Carolina	15.98	16.01	17.34	16.81	17.31	17.57	15.09	12.06	11.68	12.91	1.58	-0.91	-5.28	-5.14	-4.40
	Tennessee	15.84	16.04	17.28	17.06	12.44	16.64	9.33	8.94	8.89	8.92	0.80	-6.71	-8.34	-8.17	-3.52
	Virginia	25.68	25.05	24.19	20.22	17.49	25.16	21.60	15.09	14.10	14.16	-0.52	-3.45	-9.10	-6.12	-3.32
	West Virginia	30.03	28.84	30.57	25.42	22.52	29.98	25.48	22.10	21.30	21.46	-0.05	-3.37	-8.46	-4.13	-1.06
VISTAS Total		384.93	279.23	272.67	219.65	200.63	393.79	232.32	155.32	153.27	156.57	8.85	-46.91	-117.35	-66.39	-44.06
CENRAP	Arkansas	20.41	14.25	14.67	15.20	15.84	20.41	14.23	7.34	5.32	6.12	0.00	-0.03	-7.33	-9.88	-9.72
	Iowa	32.58	18.17	22.00	20.63	21.01	33.60	17.55	8.94	8.79	8.43	1.03	-0.62	-13.07	-11.84	-12.58
	Kansas	36.80	36.80	36.86	23.79	23.86	36.80	37.07	36.88	23.81	23.91	0.00	0.27	0.02	0.03	0.04
	Louisiana	23.29	14.60	15.67	15.00	15.97	23.42	13.86	7.29	7.19	8.19	0.13	-0.75	-8.38	-7.81	-7.78

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	33.21	18.53	17.78	17.65	17.76	32.89	15.79	8.15	7.61	7.60	-0.32	-2.75	-9.62	-10.04	-10.16
	Missouri	31.11	29.96	32.81	29.80	29.49	31.60	27.90	21.68	20.82	19.65	0.49	-2.06	-11.13	-8.98	-9.84
	Nebraska	22.49	22.51	22.51	17.07	17.11	22.52	22.55	22.55	17.11	17.13	0.03	0.04	0.03	0.04	0.01
	Oklahoma	34.87	38.92	36.74	25.77	25.38	34.79	41.16	37.05	28.43	27.47	-0.08	2.24	0.30	2.66	2.09
	Texas	89.83	84.14	86.94	86.85	85.82	88.29	72.23	50.44	49.58	46.21	-1.54	-11.91	-36.50	-37.27	-39.60
CENRAP Total		324.58	277.90	285.98	251.76	252.23	324.33	262.33	200.31	168.66	164.70	-0.26	-15.57	-85.67	-83.10	-87.53
WRAP	Arizona	35.13	35.14	36.28	30.09	31.66	35.14	35.12	36.48	30.18	32.00	0.01	-0.01	0.19	0.09	0.34
	California	12.71	13.83	11.61	12.53	13.83	12.70	14.10	11.34	12.43	13.55	-0.01	0.27	-0.27	-0.10	-0.28
	Colorado	29.98	30.12	30.17	26.60	27.04	29.98	30.24	30.16	26.62	27.03	0.00	0.12	-0.01	0.01	-0.01
	Idaho	0.31	0.31	0.34	0.34	0.34	0.31	0.31	0.37	0.37	0.37	0.00	0.00	0.03	0.03	0.03
	Montana	17.00	17.00	17.15	17.15	17.16	17.00	17.01	17.17	17.17	17.18	0.00	0.01	0.02	0.02	0.02
	Nevada	20.90	20.93	20.93	13.65	14.06	20.90	20.99	20.98	13.71	14.18	0.00	0.06	0.05	0.06	0.12
	New Mexico	32.68	32.83	33.03	32.13	32.48	32.68	32.84	33.11	32.24	32.64	0.00	0.01	0.08	0.11	0.16
	North Dakota	31.60	31.74	31.73	17.63	17.66	31.18	31.77	31.77	17.68	17.68	-0.41	0.02	0.04	0.06	0.02
	Oregon	4.76	4.76	6.23	6.23	6.23	4.76	4.76	6.42	6.42	6.42	0.00	0.00	0.19	0.19	0.19
	South Dakota	6.44	6.44	6.44	0.77	0.81	6.45	6.46	6.45	0.80	0.81	0.01	0.02	0.01	0.03	0.00
	Utah	26.91	26.91	26.91	23.64	23.60	26.91	26.91	26.91	23.64	23.60	0.00	0.00	0.00	0.00	0.00
	Washington	11.19	11.52	14.01	9.41	9.41	11.19	11.19	14.21	9.77	9.77	0.00	-0.33	0.20	0.37	0.37
	Wyoming	35.93	35.93	35.93	23.49	23.54	35.93	35.93	35.93	23.49	23.54	0.00	0.00	0.00	0.00	0.01
WRAP Total		265.54	267.46	270.77	213.66	217.81	265.13	267.62	271.31	214.53	218.78	-0.41	0.17	0.54	0.87	0.97
CAIR Plus Policy States		940.26	754.74	730.08	660.09	636.33	945.41	652.79	437.45	425.01	421.93	5.16	-101.95	-292.63	-235.08	-214.39
National		1,299.95	1,120.44	1,096.96	940.38	920.49	1,304.66	1,021.20	805.23	708.90	709.22	4.71	-99.24	-291.74	-231.48	-211.27

Table A5.4: State Level Fixed O&M Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	433.6	434.1	457.0	468.9	506.5	436.3	436.8	463.5	478.3	511.6	2.7	2.7	6.5	9.4	5.1
	Delaware	59.0	59.0	66.5	69.5	71.2	55.5	55.5	58.8	62.6	65.7	-3.5	-3.5	-7.8	-6.9	-5.5
	District of Columbia	14.2	14.2	15.4	20.8	22.9	14.2	14.2	16.8	20.7	22.0	0.0	0.0	1.4	-0.1	-1.0
	Maine	61.5	61.5	56.1	60.7	64.1	62.4	62.8	68.8	74.6	76.4	0.9	1.3	12.7	13.9	12.2
	Maryland	460.1	475.4	503.3	587.3	617.0	464.9	480.2	526.9	587.2	605.8	4.8	4.8	23.6	-0.1	-11.2
	Massachusetts	442.0	443.2	427.7	448.2	465.0	441.1	442.3	432.1	460.0	468.6	-0.9	-0.9	4.4	11.7	3.7
	New Hampshire	209.5	209.5	225.7	234.1	240.4	211.2	211.2	227.1	237.8	241.1	1.7	1.7	1.4	3.7	0.7
	New Jersey	856.7	856.7	896.5	919.5	959.3	853.3	853.3	891.3	919.8	970.2	-3.4	-3.4	-5.1	0.3	10.9
	New York	1,429.0	1,429.1	1,502.5	1,563.6	1,604.4	1,426.6	1,426.7	1,506.8	1,544.9	1,607.0	-2.4	-2.4	4.3	-18.7	2.6
	Pennsylvania	1,968.4	1,972.2	2,027.5	2,105.6	2,191.4	1,963.6	1,960.7	2,014.8	2,103.8	2,198.9	-4.8	-11.5	-12.7	-1.8	7.5
	Rhode Island	22.2	22.2	20.5	23.1	25.0	21.3	21.3	21.9	25.1	26.0	-0.9	-0.9	1.4	2.0	1.1
	Vermont	120.2	120.2	123.3	125.2	126.4	120.5	120.5	124.2	126.5	127.1	0.3	0.3	0.9	1.3	0.7
MANE-VU Total		6,076.4	6,097.3	6,322.0	6,626.6	6,893.7	6,070.8	6,085.3	6,352.9	6,641.2	6,920.4	-5.6	-11.9	30.9	14.6	26.7
LADCO	Illinois	2,021.9	2,022.7	2,058.7	2,168.5	2,391.2	2,028.4	2,023.5	2,060.8	2,178.8	2,395.1	6.6	0.8	2.1	10.3	3.9
	Indiana	625.1	634.1	672.6	716.8	727.8	622.8	629.2	680.3	735.0	766.9	-2.3	-5.0	7.8	18.2	39.1
	Michigan	1,094.0	1,094.1	1,094.7	1,132.7	1,236.4	1,084.0	1,084.1	1,101.7	1,141.9	1,200.1	-10.1	-10.1	7.0	9.2	-36.3
	Ohio	1,031.1	1,058.5	1,129.5	1,170.0	1,205.8	1,048.8	1,046.4	1,127.7	1,196.1	1,252.1	17.7	-12.1	-1.8	26.1	46.3
	Wisconsin	515.7	515.9	529.6	552.9	589.7	507.1	507.7	531.1	552.5	578.9	-8.6	-8.2	1.5	-0.5	-10.8
LADCO Total		5,287.7	5,325.4	5,485.1	5,741.0	6,150.8	5,291.0	5,290.8	5,501.6	5,804.3	6,193.0	3.3	-34.5	16.6	63.3	42.1
VISTAS	Alabama	987.4	989.5	1,030.4	1,123.6	1,181.0	987.0	986.7	1,064.0	1,130.5	1,190.9	-0.3	-2.8	33.6	6.9	9.9
	Florida	1,355.1	1,356.0	1,503.5	1,678.5	1,745.0	1,355.2	1,356.1	1,519.8	1,697.1	1,733.5	0.1	0.1	16.3	18.6	-11.4
	Georgia	835.8	857.9	901.2	1,089.1	1,208.6	836.1	878.2	989.8	1,107.1	1,229.5	0.2	20.3	88.6	18.0	20.9
	Kentucky	495.5	496.2	533.6	556.5	569.1	494.7	494.0	542.3	582.2	592.5	-0.8	-2.1	8.6	25.7	23.4
	Mississippi	307.9	311.1	312.8	389.1	411.0	305.9	309.2	333.8	385.2	407.0	-2.0	-2.0	21.0	-4.0	-4.0
	North Carolina	970.1	986.3	1,087.7	1,189.6	1,251.6	969.0	986.1	1,095.3	1,188.7	1,248.9	-1.1	-0.2	7.5	-0.9	-2.8
	South Carolina	936.7	936.8	995.5	1,088.5	1,148.3	936.6	936.6	1,002.3	1,093.9	1,163.2	-0.2	-0.2	6.9	5.3	14.9
	Tennessee	663.6	664.6	735.2	754.3	782.6	663.4	664.4	747.6	785.4	794.3	-0.3	-0.3	12.4	31.1	11.8
	Virginia	625.6	625.6	719.5	789.7	831.7	620.4	614.8	718.0	790.4	826.4	-5.2	-10.7	-1.6	0.7	-5.3
	West Virginia	517.6	529.5	576.1	605.8	613.3	535.9	541.2	584.3	609.5	622.5	18.3	11.7	8.2	3.7	9.2
VISTAS Total		7,695.4	7,753.4	8,395.5	9,264.7	9,742.2	7,704.2	7,767.2	8,597.1	9,369.9	9,808.7	8.8	13.8	201.6	105.3	66.6
CENRAP	Arkansas	383.8	383.8	421.2	465.1	484.1	383.8	383.8	422.9	458.4	485.8	0.0	0.0	1.7	-6.7	1.7
	Iowa	274.5	282.0	285.1	297.5	303.1	275.7	277.7	283.0	286.7	290.9	1.2	-4.3	-2.1	-10.8	-12.2
	Kansas	340.7	341.6	357.5	395.1	414.5	337.5	338.4	354.2	391.9	394.6	-3.3	-3.3	-3.3	-3.2	-19.9
	Louisiana	437.9	437.9	468.7	524.8	583.9	438.1	442.8	471.9	527.6	584.8	0.3	5.0	3.2	2.7	0.9

RPO	State	MARAMA Base Case (MARAMA_5c) 2008	2009	2012	2015	2018	MARAMA CAIR Plus Policy Case (MARAMA_4c) 2008	2009	2012	2015	2018	MARAMA_4c - MARAMA_5c 2008	2009	2012	2015	2018
	Minnesota	443.2	441.2	447.3	447.3	453.0	444.6	439.3	446.4	450.2	454.6	1.4	-1.9	-0.9	3.0	1.6
	Missouri	444.5	447.6	457.3	506.9	538.8	445.3	443.6	455.7	494.6	535.6	0.8	-4.0	-1.6	-12.3	-3.2
	Nebraska	303.8	309.8	313.9	325.3	326.0	304.4	310.4	314.5	325.5	325.9	0.6	0.6	0.6	0.2	-0.1
	Oklahoma	301.4	301.4	350.9	386.1	418.3	301.4	301.4	351.1	385.3	414.0	0.0	0.0	0.2	-0.9	-4.3
	Texas	1,985.4	2,015.4	2,328.6	2,424.2	2,631.0	1,983.1	2,017.0	2,341.9	2,449.9	2,626.5	-2.3	1.7	13.3	25.7	-4.5
CENRAP Total		4,915.3	4,960.7	5,430.4	5,772.5	6,152.8	4,913.9	4,954.5	5,441.5	5,770.2	6,112.7	-1.3	-6.2	11.1	-2.3	-40.1
WRAP	Arizona	711.5	716.5	756.1	756.1	900.0	691.9	696.9	744.5	749.6	893.6	-19.7	-19.7	-11.5	-6.5	-6.4
	California	1,515.4	1,518.2	1,545.8	1,698.7	1,760.8	1,544.9	1,547.6	1,569.3	1,717.1	1,779.2	29.4	29.4	23.5	18.4	18.4
	Colorado	197.0	201.0	204.3	224.7	232.0	196.0	199.9	203.2	223.6	232.1	-1.1	-1.1	-1.1	-1.1	0.1
	Idaho	49.1	49.1	52.9	52.9	52.9	49.1	49.1	53.8	53.8	53.8	0.0	0.0	0.9	0.9	0.9
	Montana	136.5	142.9	147.1	147.1	150.6	136.5	143.0	147.7	147.7	151.2	0.0	0.0	0.6	0.6	0.6
	Nevada	184.7	185.5	197.3	207.4	218.4	184.7	185.5	199.3	210.7	221.7	0.0	0.0	2.0	3.3	3.3
	New Mexico	171.5	171.5	186.3	194.6	205.9	171.5	171.5	187.3	189.8	208.5	0.0	0.0	0.9	-4.8	2.5
	North Dakota	142.1	142.1	147.2	163.5	163.9	140.5	140.5	145.6	152.6	161.9	-1.6	-1.6	-1.6	-10.8	-2.0
	Oregon	252.9	252.9	295.6	295.6	295.6	252.9	252.9	300.9	300.9	300.9	0.0	0.0	5.3	5.3	5.3
	South Dakota	44.2	44.2	44.2	47.9	48.3	44.4	44.4	44.4	48.2	48.3	0.2	0.2	0.2	0.3	0.0
	Utah	162.4	162.4	162.4	164.3	179.6	162.4	162.4	162.4	164.3	179.7	0.0	0.0	0.0	0.0	0.0
	Washington	597.7	598.8	674.6	700.7	700.7	597.7	598.8	682.9	710.8	710.8	0.0	0.0	8.3	10.0	10.0
	Wyoming	228.7	228.7	236.4	236.4	248.3	228.8	228.8	236.4	236.4	248.5	0.0	0.0	0.0	0.0	0.2
WRAP Total		4,393.9	4,413.8	4,650.2	4,889.9	5,157.3	4,401.3	4,421.2	4,677.8	4,905.5	5,190.2	7.4	7.4	27.7	15.6	33.0
CAIR Plus Policy States		23,028.9	23,184.0	24,610.6	26,298.2	27,780.7	23,036.7	23,147.7	24,873.4	26,482.9	27,900.2	7.8	-36.2	262.7	184.7	119.6
National		28,368.7	28,550.7	30,283.1	32,294.7	34,096.7	28,381.2	28,519.1	30,571.0	32,491.1	34,225.0	12.6	-31.5	287.9	196.3	128.3

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.5: State Level Variable O&M Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	45.2	48.4	67.2	71.7	78.7	44.6	51.3	55.4	62.0	63.2	-0.6	2.9	-11.7	-9.6	-15.4
	Delaware	15.9	19.5	24.0	22.7	23.2	15.9	18.7	18.6	11.1	11.0	0.0	-0.8	-5.4	-11.6	-12.2
	District of Columbia	0.0	0.0	1.5	4.6	7.3	0.0	0.0	3.2	5.5	7.1	0.0	0.0	1.8	0.9	-0.2
	Maine	29.6	29.9	23.8	24.0	25.8	28.7	28.7	19.1	21.4	21.6	-0.8	-1.2	-4.7	-2.7	-4.2
	Maryland	102.9	129.6	152.8	196.0	232.0	105.4	130.9	178.2	207.4	228.4	2.5	1.3	25.3	11.4	-3.6
	Massachusetts	115.6	99.3	136.2	133.8	145.9	115.8	98.5	112.3	116.1	119.6	0.2	-0.8	-23.9	-17.8	-26.4
	New Hampshire	29.2	30.7	49.1	51.7	57.0	29.2	29.6	38.2	43.8	45.3	0.0	-1.1	-10.9	-7.9	-11.7
	New Jersey	91.3	96.4	99.8	96.3	100.3	91.3	102.2	98.5	98.0	105.7	0.0	5.8	-1.3	1.7	5.4
	New York	165.0	167.1	284.2	304.1	310.5	167.3	167.6	308.3	317.0	328.7	2.3	0.5	24.1	12.9	18.2
	Pennsylvania	427.8	471.9	537.7	532.4	534.7	432.0	469.1	531.3	528.5	529.1	4.2	-2.8	-6.3	-3.9	-5.6
	Rhode Island	1.9	5.1	6.5	7.6	9.2	1.9	5.1	3.8	5.5	5.7	0.0	0.0	-2.6	-2.1	-3.4
	Vermont	6.0	6.0	9.9	10.3	11.2	6.0	6.0	8.1	9.1	9.1	0.0	0.0	-1.8	-1.2	-2.1
MANE-VU Total		1,030.4	1,104.1	1,392.5	1,455.3	1,535.9	1,038.1	1,107.9	1,375.0	1,425.5	1,474.6	7.7	3.8	-17.5	-29.9	-61.3
LADCO	Illinois	289.8	308.1	367.0	377.8	460.7	292.8	301.3	377.7	392.3	482.3	3.0	-6.7	10.7	14.5	21.6
	Indiana	309.2	353.4	390.3	426.6	432.7	309.5	341.8	426.4	452.1	468.0	0.3	-11.6	36.1	25.6	35.3
	Michigan	190.4	212.8	212.0	247.4	338.6	191.4	219.1	255.4	288.2	318.8	1.1	6.3	43.4	40.8	-19.8
	Ohio	408.3	519.5	568.8	591.5	592.6	429.3	507.4	568.1	600.5	610.4	20.9	-12.1	-0.7	9.0	17.7
	Wisconsin	127.2	129.7	145.7	164.2	185.9	128.9	137.6	166.1	184.3	206.7	1.7	7.9	20.4	20.1	20.8
LADCO Total		1,324.8	1,523.5	1,683.9	1,807.5	2,010.5	1,351.8	1,507.1	1,793.7	1,917.4	2,086.2	26.9	-16.4	109.8	109.9	75.6
VISTAS	Alabama	219.5	256.9	298.0	347.1	377.4	213.3	246.9	336.1	357.0	400.5	-6.2	-10.1	38.1	9.9	23.1
	Florida	325.0	348.4	513.0	581.5	658.2	325.0	345.8	524.7	598.3	627.2	0.0	-2.6	11.6	16.8	-31.0
	Georgia	204.6	252.0	321.3	411.7	465.0	204.6	277.6	445.7	485.3	554.3	0.0	25.5	124.4	73.6	89.3
	Kentucky	267.7	305.5	346.3	362.9	373.9	262.1	281.2	360.1	381.4	386.4	-5.6	-24.3	13.8	18.5	12.6
	Mississippi	56.6	61.3	66.1	104.2	120.8	56.6	72.0	91.0	107.2	126.1	0.0	10.7	25.0	3.0	5.3
	North Carolina	283.9	245.0	293.0	316.7	360.5	284.1	243.9	302.9	323.2	358.9	0.2	-1.1	9.9	6.5	-1.6
	South Carolina	170.8	190.8	243.5	260.3	296.8	166.7	184.9	250.3	269.0	312.6	-4.1	-5.9	6.7	8.7	15.8
	Tennessee	159.8	186.5	195.0	194.1	212.9	155.4	162.7	203.9	213.5	217.9	-4.4	-23.7	8.8	19.4	5.0
	Virginia	121.8	133.7	189.2	212.4	253.9	121.9	130.3	201.6	224.7	255.5	0.0	-3.5	12.3	12.3	1.6
	West Virginia	285.2	326.2	391.7	413.0	419.4	314.3	355.9	407.0	418.5	427.0	29.1	29.8	15.3	5.5	7.6
VISTAS Total		2,095.0	2,306.3	2,857.3	3,203.9	3,538.9	2,104.1	2,301.2	3,123.2	3,378.1	3,666.5	9.1	-5.1	265.9	174.1	127.6
CENRAP	Arkansas	65.6	71.0	81.8	128.4	148.4	65.7	80.4	88.7	137.5	162.2	0.1	9.4	6.9	9.1	13.8
	Iowa	85.2	93.0	96.9	101.5	108.3	86.2	98.0	113.4	115.7	120.5	0.9	5.0	16.5	14.2	12.2
	Kansas	104.9	105.1	105.3	118.2	128.9	104.9	105.8	105.4	118.2	120.2	0.0	0.8	0.1	0.0	-8.8
	Louisiana	80.6	82.2	109.1	137.6	174.0	82.0	94.2	124.2	149.0	182.4	1.4	12.0	15.1	11.3	8.4

RPO	State	MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
		2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	111.9	107.1	105.8	105.7	106.2	111.8	108.0	120.0	124.2	123.4	-0.2	1.0	14.2	18.5	17.1
	Missouri	145.5	172.1	177.7	193.3	218.1	143.9	151.4	182.9	187.6	230.0	-1.6	-20.8	5.3	-5.7	11.9
	Nebraska	47.6	47.7	47.7	73.1	73.1	47.6	47.7	47.7	72.9	72.9	0.0	0.0	0.0	-0.2	-0.2
	Oklahoma	110.7	118.9	151.2	173.3	194.0	110.7	127.0	152.0	178.4	200.6	0.0	8.2	0.8	5.1	6.6
	Texas	601.2	621.5	876.4	935.3	1,030.5	603.3	627.8	950.4	1,021.3	1,081.6	2.1	6.3	74.0	85.9	51.1
CENRAP Total		1,353.3	1,418.6	1,751.9	1,966.5	2,181.6	1,356.1	1,440.5	1,884.7	2,104.9	2,293.9	2.9	21.9	132.8	138.3	112.3
WRAP	Arizona	198.3	199.3	245.3	246.0	302.5	198.4	199.3	253.6	257.0	316.8	0.1	0.0	8.3	11.0	14.2
	California	504.9	528.5	522.1	602.3	648.8	504.0	530.8	513.1	590.5	632.8	-1.0	2.3	-9.0	-11.8	-16.0
	Colorado	93.3	98.4	99.3	112.1	123.3	93.3	99.1	99.3	111.9	124.0	0.0	0.7	0.0	-0.2	0.7
	Idaho	2.5	2.5	9.4	9.4	9.4	2.5	2.5	10.6	10.6	10.6	0.0	0.0	1.2	1.2	1.2
	Montana	48.7	48.7	53.9	53.9	54.2	48.7	48.7	54.6	54.6	54.9	0.0	0.0	0.7	0.7	0.7
	Nevada	91.7	94.4	108.3	113.1	126.7	91.7	94.7	110.7	116.8	130.7	0.0	0.3	2.4	3.8	4.0
	New Mexico	86.3	86.7	101.3	104.6	118.3	86.3	86.8	100.2	102.4	121.6	0.0	0.1	-1.0	-2.2	3.3
	North Dakota	71.8	72.2	72.1	81.9	82.0	69.9	71.2	71.2	77.1	81.0	-1.9	-0.9	-0.9	-4.8	-0.9
	Oregon	23.9	23.9	74.1	74.1	74.1	23.9	23.9	80.6	80.6	80.6	0.0	0.0	6.5	6.5	6.5
	South Dakota	5.4	5.4	5.5	9.6	9.9	5.4	5.5	5.5	9.7	9.9	0.0	0.0	0.0	0.1	0.0
	Utah	88.3	88.3	88.3	88.3	91.8	88.3	88.3	88.3	88.3	91.8	0.0	0.0	0.0	0.0	0.0
	Washington	51.1	53.7	146.4	145.4	145.4	51.1	52.7	157.9	157.9	157.9	0.0	-0.9	11.4	12.4	12.4
	Wyoming	116.8	116.8	117.4	117.4	124.2	116.8	116.8	117.4	117.4	124.4	0.0	0.0	0.0	0.0	0.2
WRAP Total		1,383.1	1,418.8	1,643.5	1,758.2	1,910.5	1,380.3	1,420.3	1,663.2	1,775.0	1,937.0	-2.8	1.6	19.6	16.8	26.4
CAIR Plus Policy States		5,540.3	6,080.8	7,381.3	8,068.7	8,870.8	5,586.8	6,076.1	7,871.6	8,456.2	9,127.4	46.6	-4.8	490.2	387.5	256.6
National		7,186.6	7,771.3	9,329.1	10,191.5	11,177.4	7,230.4	7,777.0	9,839.8	10,600.8	11,458.1	43.8	5.8	510.7	409.3	280.7

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.6: State Level Annualized Capital Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	99.6	99.6	269.5	345.1	413.3	116.9	116.9	287.6	379.6	414.3	17.3	17.3	18.2	34.5	1.0
	Delaware	10.6	10.6	28.7	40.6	49.3	10.8	10.8	18.0	34.9	52.1	0.2	0.2	-10.8	-5.7	2.7
	District of Columbia	1.8	1.8	10.2	42.2	57.5	1.8	1.8	20.3	43.5	52.5	0.0	0.0	10.0	1.4	-4.9
	Maine	34.5	34.5	100.7	129.8	156.2	41.0	42.6	108.5	144.0	157.4	6.4	8.1	7.9	14.2	1.3
	Maryland	91.4	139.0	267.5	708.9	915.7	102.4	150.0	411.4	730.1	858.2	11.0	11.0	144.0	21.2	-57.5
	Massachusetts	209.9	209.9	528.7	670.5	798.6	245.2	245.2	565.7	738.1	803.4	35.4	35.4	37.0	67.7	4.8
	New Hampshire	75.7	75.7	196.0	249.5	297.9	87.5	87.5	208.5	274.1	298.7	11.8	11.8	12.4	24.6	0.9
	New Jersey	23.6	23.6	71.7	147.7	203.1	25.0	25.0	70.6	178.8	289.2	1.5	1.5	-1.1	31.1	86.1
	New York	172.1	172.1	1,097.4	1,426.5	1,494.1	190.1	190.1	1,252.0	1,441.4	1,643.9	18.0	18.0	154.6	14.9	149.8
	Pennsylvania	87.0	91.5	282.7	386.9	431.6	92.6	92.6	291.5	454.7	565.6	5.6	1.1	8.8	67.8	134.0
	Rhode Island	19.2	19.2	55.8	72.1	86.8	22.8	22.8	59.6	79.4	86.9	3.6	3.6	3.8	7.3	0.1
	Vermont	12.1	12.1	35.3	45.7	55.0	14.4	14.4	37.7	50.3	55.1	2.3	2.3	2.4	4.6	0.1
MANE-VU Total		837.4	889.6	2,944.2	4,265.4	4,959.1	950.5	999.8	3,331.4	4,549.0	5,277.3	113.1	110.3	387.2	283.6	318.2
LADCO	Illinois	44.1	44.2	133.6	265.4	801.4	60.0	60.0	170.2	354.8	870.1	15.9	15.8	36.6	89.4	68.7
	Indiana	26.6	43.6	110.4	311.2	349.1	31.3	52.1	222.1	492.8	640.5	4.7	8.5	111.7	181.6	291.4
	Michigan	6.4	6.4	6.4	220.4	753.0	7.2	7.2	172.3	399.3	594.7	0.8	0.8	165.8	178.9	-158.4
	Ohio	97.3	175.0	525.2	748.7	762.4	140.9	169.3	485.0	841.3	990.6	43.5	-5.7	-40.1	92.7	228.2
	Wisconsin	14.9	14.9	50.3	159.9	256.2	0.4	3.9	118.6	236.2	386.0	-14.6	-11.0	68.3	76.3	129.8
LADCO Total		189.3	284.1	825.9	1,705.6	2,922.2	239.7	292.5	1,168.2	2,324.5	3,481.9	50.4	8.4	342.3	618.9	559.7
VISTAS	Alabama	20.8	20.8	83.4	521.4	814.8	17.4	31.6	278.4	553.6	877.3	-3.4	10.8	195.0	32.2	62.5
	Florida	13.0	26.7	941.9	1,717.7	2,125.8	13.0	27.0	1,052.4	1,855.0	2,051.0	0.0	0.3	110.5	137.3	-74.7
	Georgia	1.4	1.4	112.6	864.8	1,343.9	2.6	56.5	508.8	931.3	1,446.5	1.2	55.1	396.2	66.6	102.6
	Kentucky	8.2	9.8	86.6	190.5	230.4	5.8	5.8	169.7	325.0	386.8	-2.4	-3.9	83.0	134.5	156.3
	Mississippi	0.5	0.5	15.0	236.4	365.2	0.7	0.7	109.2	230.1	362.8	0.2	0.2	94.1	-6.3	-2.4
	North Carolina	234.1	275.2	623.4	866.4	1,113.6	234.2	275.1	677.4	878.4	1,117.3	0.1	-0.1	54.0	12.0	3.7
	South Carolina	23.3	23.4	321.4	535.7	748.9	21.8	21.8	381.9	573.7	807.4	-1.5	-1.6	60.5	38.0	58.5
	Tennessee	18.0	18.0	31.6	31.6	107.1	15.7	15.7	80.9	125.8	146.5	-2.3	-2.3	49.4	94.2	39.4
	Virginia	9.7	9.7	307.1	539.7	766.4	10.8	10.8	373.6	591.6	804.4	1.0	1.0	66.4	51.9	37.9
	West Virginia	2.7	2.7	139.8	281.7	313.6	52.0	62.6	202.5	352.8	431.9	49.3	59.9	62.6	71.1	118.4
VISTAS Total		331.9	388.3	2,662.9	5,785.8	7,929.6	374.1	507.7	3,834.8	6,417.4	8,431.9	42.2	119.3	1,171.8	631.6	502.3
CENRAP	Arkansas	0.1	0.1	45.9	191.3	314.3	0.1	0.1	71.0	224.9	349.3	0.0	0.0	25.1	33.7	34.9
	Iowa	0.0	0.7	0.7	10.4	17.3	2.4	4.9	45.6	46.1	52.8	2.4	4.2	44.9	35.7	35.5
	Kansas	0.0	0.0	0.0	22.2	71.5	0.0	0.0	0.0	22.3	39.4	0.0	0.0	0.0	0.0	-32.1
	Louisiana	0.1	0.1	107.6	290.4	508.7	0.1	11.8	149.1	326.0	532.0	0.0	11.6	41.5	35.6	23.3

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	45.1	84.0	84.1	84.1	86.9	47.9	88.7	119.2	132.0	132.0	2.8	4.6	35.2	47.9	45.1
	Missouri	2.8	14.1	19.7	91.3	257.6	4.7	5.6	53.6	117.9	307.1	2.0	-8.6	33.9	26.7	49.5
	Nebraska	0.0	0.0	0.0	34.4	35.7	1.2	1.2	1.2	35.3	35.7	1.2	1.2	1.2	0.8	0.0
	Oklahoma	0.5	0.5	237.8	345.3	524.2	0.5	0.5	239.1	351.6	521.5	0.0	0.0	1.2	6.3	-2.7
	Texas	225.6	225.6	2,245.5	2,610.3	3,446.4	243.1	260.7	2,399.5	2,822.6	3,626.5	17.5	35.1	154.0	212.2	180.1
CENRAP Total		274.2	325.2	2,741.4	3,679.7	5,262.7	300.1	373.4	3,078.2	4,078.7	5,596.3	25.9	48.2	336.9	399.0	333.6
WRAP	Arizona	2.8	2.8	264.0	264.0	583.3	2.8	2.8	322.2	357.9	677.7	0.0	0.0	58.2	93.9	94.4
	California	792.1	792.1	980.4	1,506.9	1,691.7	823.0	823.0	964.9	1,453.1	1,637.9	30.9	30.9	-15.4	-53.8	-53.8
	Colorado	0.0	0.0	0.0	42.3	93.4	0.0	0.0	0.0	42.2	102.3	0.0	0.0	0.0	-0.2	8.9
	Idaho	9.0	9.0	61.8	61.8	61.8	9.0	9.0	68.7	68.7	68.7	0.0	0.0	6.9	6.9	6.9
	Montana	5.2	5.2	36.0	36.0	37.5	5.3	5.3	40.1	40.1	41.7	0.1	0.1	4.1	4.1	4.3
	Nevada	0.7	0.7	65.7	70.5	148.6	0.7	0.7	80.2	93.9	171.8	0.0	0.0	14.5	23.4	23.3
	New Mexico	0.6	0.6	68.1	75.4	152.1	0.6	0.6	80.7	90.4	172.8	0.0	0.0	12.6	14.9	20.7
	North Dakota	23.2	23.2	23.2	48.0	48.8	19.3	19.3	19.3	36.2	44.2	-3.8	-3.8	-3.8	-11.8	-4.6
	Oregon	50.2	50.2	346.1	346.1	346.1	50.2	50.2	384.7	384.7	384.7	0.0	0.0	38.6	38.6	38.6
	South Dakota	0.0	0.0	0.0	13.3	14.8	0.5	0.5	0.5	13.9	14.9	0.5	0.5	0.5	0.6	0.1
	Utah	0.0	0.0	0.0	0.0	15.6	0.0	0.0	0.0	0.0	15.7	0.0	0.0	0.0	0.0	0.1
	Washington	95.2	95.2	657.3	657.3	657.3	95.2	95.2	730.5	730.5	730.5	0.0	0.0	73.3	73.3	73.3
	Wyoming	0.0	0.0	0.0	0.0	33.5	0.1	0.1	0.1	0.1	34.9	0.1	0.1	0.1	0.1	1.4
WRAP Total		979.0	979.0	2,502.6	3,121.7	3,884.3	1,006.7	1,006.7	2,692.0	3,311.7	4,097.9	27.7	27.7	189.4	190.0	213.6
CAIR Plus Policy States		1,632.3	1,886.6	8,936.5	15,034.5	20,442.3	1,862.7	2,171.6	11,172.4	16,960.4	22,190.9	230.4	285.0	2,235.8	1,925.9	1,748.7
National		2,611.8	2,866.1	11,677.0	18,558.1	24,958.0	2,871.1	3,180.0	14,104.7	20,681.3	26,885.4	259.3	313.9	2,427.7	2,123.1	1,927.4

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.7: State Level Fuel Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	768.8	806.3	312.3	286.3	289.9	724.6	1,058.0	330.8	278.7	288.6	-44.1	251.7	18.5	-7.6	-1.4
	Delaware	133.8	132.5	126.9	118.1	121.2	134.7	141.9	114.8	63.2	61.2	0.9	9.4	-12.2	-54.9	-60.0
	District of Columbia	0.8	4.6	4.6	14.6	21.7	1.0	5.1	9.4	16.6	20.6	0.1	0.5	4.8	2.0	-1.1
	Maine	594.3	580.6	219.4	203.1	199.9	578.1	569.5	211.6	204.9	201.1	-16.2	-11.1	-7.8	1.7	1.2
	Maryland	548.2	562.5	574.2	691.8	782.3	545.6	567.2	634.3	718.8	760.9	-2.6	4.6	60.1	27.0	-21.4
	Massachusetts	2,558.0	2,382.5	1,509.2	1,097.8	1,088.0	2,530.1	2,474.2	1,488.2	1,103.7	1,194.3	-27.9	91.7	-21.0	5.9	106.3
	New Hampshire	161.6	254.6	197.1	197.5	208.7	158.3	257.9	166.4	178.8	187.3	-3.3	3.3	-30.7	-18.7	-21.4
	New Jersey	791.9	844.7	686.7	575.2	624.8	789.6	1,226.1	676.7	610.3	673.9	-2.4	381.4	-10.0	35.1	49.1
	New York	3,017.9	3,031.9	1,809.5	1,615.5	1,705.7	3,043.8	3,410.1	1,765.3	1,676.8	1,736.8	25.9	378.2	-44.3	61.3	31.1
	Pennsylvania	2,676.7	2,878.9	2,501.0	2,286.8	2,210.0	2,742.5	3,601.3	2,442.4	2,299.3	2,269.6	65.8	722.4	-58.6	12.4	59.6
	Rhode Island	118.9	305.2	33.3	35.7	36.1	118.7	338.1	35.5	33.7	33.4	-0.2	33.0	2.2	-2.0	-2.7
	Vermont	22.4	23.2	34.0	35.3	37.4	22.4	22.8	30.7	34.3	33.9	0.0	-0.4	-3.3	-1.1	-3.5
MANE-VU Total		11,393.4	11,807.5	8,008.2	7,157.8	7,325.7	11,389.3	13,672.2	7,905.9	7,218.9	7,461.5	-4.0	1,864.7	-102.3	61.1	135.8
LADCO	Illinois	1,792.0	1,761.4	1,822.0	1,780.1	1,832.1	1,793.8	1,747.9	1,803.1	1,752.7	1,808.5	1.8	-13.5	-18.9	-27.4	-23.5
	Indiana	1,659.0	1,765.3	1,608.0	1,539.3	1,445.0	1,684.7	2,042.4	1,575.6	1,527.2	1,503.8	25.7	277.1	-32.4	-12.0	58.8
	Michigan	1,511.1	1,599.1	1,445.7	1,458.5	1,572.6	1,528.2	1,991.8	1,488.3	1,459.7	1,458.7	17.1	392.6	42.6	1.2	-113.9
	Ohio	2,198.6	2,389.0	2,162.0	2,099.3	2,058.3	2,161.3	2,640.3	2,067.8	2,069.3	2,033.2	-37.2	251.3	-94.2	-30.0	-25.2
	Wisconsin	752.4	770.8	757.7	716.9	710.5	804.4	859.9	726.2	706.9	699.2	52.0	89.1	-31.5	-10.0	-11.3
LADCO Total		7,913.0	8,285.7	7,795.4	7,594.1	7,618.5	7,972.5	9,282.2	7,661.0	7,515.8	7,503.3	59.5	996.5	-134.4	-78.3	-115.2
VISTAS	Alabama	2,349.4	2,611.5	2,296.2	1,977.2	1,975.6	2,352.9	3,291.0	2,237.1	1,981.0	2,029.4	3.5	679.5	-59.1	3.9	53.8
	Florida	6,214.9	6,265.3	4,440.6	4,101.8	4,245.8	6,215.1	7,332.2	4,264.5	4,167.0	4,416.4	0.2	1,066.9	-176.1	65.2	170.7
	Georgia	3,109.1	3,276.3	2,525.7	2,439.5	2,536.7	3,086.8	3,272.5	2,527.8	2,500.4	2,624.9	-22.3	-3.7	2.1	60.9	88.2
	Kentucky	1,067.2	1,050.9	980.1	1,008.9	1,015.0	1,083.2	1,020.3	969.3	1,011.4	1,017.5	16.0	-30.6	-10.9	2.5	2.6
	Mississippi	884.1	991.6	737.9	720.0	736.8	885.5	1,758.7	745.0	751.7	766.2	1.4	767.1	7.1	31.7	29.4
	North Carolina	1,439.6	1,297.9	1,358.6	1,434.3	1,526.2	1,416.1	1,387.1	1,372.9	1,446.8	1,504.8	-23.5	89.2	14.3	12.5	-21.4
	South Carolina	1,243.8	1,412.2	1,285.7	1,248.7	1,339.1	1,236.8	1,685.0	1,286.4	1,270.4	1,403.1	-7.0	272.8	0.7	21.8	63.9
	Tennessee	820.3	822.1	849.4	816.4	799.5	807.5	717.7	832.5	822.4	801.2	-12.9	-104.5	-17.0	6.0	1.8
	Virginia	1,152.1	1,587.3	1,198.4	1,138.4	1,169.9	1,155.6	1,707.8	1,148.7	1,116.4	1,167.9	3.5	120.5	-49.7	-22.0	-1.9
	West Virginia	1,074.6	1,054.2	1,000.3	1,015.2	1,005.1	1,026.7	1,007.4	960.9	1,014.9	1,013.7	-47.9	-46.8	-39.4	-0.3	8.6
VISTAS Total		19,355.1	20,369.4	16,672.8	15,900.3	16,349.6	19,266.2	23,179.8	16,344.9	16,082.3	16,745.1	-88.9	2,810.4	-327.9	182.0	395.6
CENRAP	Arkansas	1,004.4	1,208.0	1,054.6	928.9	910.6	1,009.3	1,775.0	969.8	904.8	887.5	4.9	567.1	-84.8	-24.1	-23.1
	Iowa	617.8	672.3	631.9	613.2	664.4	630.1	832.7	613.8	629.7	652.0	12.2	160.5	-18.1	16.5	-12.5
	Kansas	450.8	447.3	428.0	420.6	462.5	452.0	503.2	439.3	420.4	430.2	1.2	55.9	11.2	-0.2	-32.2
	Louisiana	1,171.6	1,223.1	994.5	873.6	881.4	1,242.0	1,764.1	983.6	837.2	875.0	70.4	541.0	-10.9	-36.4	-6.4

RPO	State	MARAMA Base Case (MARAMA_5c) 2008	2009	2012	2015	2018	MARAMA CAIR Plus Policy Case (MARAMA_4c) 2008	2009	2012	2015	2018	MARAMA_4c - MARAMA_5c 2008	2009	2012	2015	2018
	Minnesota	510.6	511.0	468.7	453.6	446.2	510.9	505.4	453.1	449.9	440.1	0.3	-5.6	-15.5	-3.6	-6.1
	Missouri	928.1	992.2	1,001.7	976.7	987.2	926.3	972.4	979.3	930.5	897.7	-1.8	-19.9	-22.4	-46.2	-89.5
	Nebraska	261.3	262.8	253.3	245.8	237.9	261.3	264.6	253.3	247.3	238.6	0.0	1.8	0.0	1.5	0.7
	Oklahoma	2,064.3	2,230.8	1,480.1	1,315.1	1,191.4	2,065.1	2,855.6	1,492.8	1,422.1	1,369.9	0.8	624.8	12.6	107.0	178.5
	Texas	11,112.6	11,303.2	6,765.2	6,275.9	6,356.6	11,116.4	12,545.3	6,753.2	6,307.3	6,359.4	3.7	1,242.1	-11.9	31.4	2.9
CENRAP Total		18,121.5	18,850.6	13,077.9	12,103.5	12,138.3	18,213.3	22,018.3	12,938.2	12,149.3	12,150.5	91.8	3,167.7	-139.8	45.8	12.2
WRAP	Arizona	3,549.0	3,407.8	2,509.3	2,289.7	2,346.7	3,552.9	3,765.2	2,479.6	2,191.9	2,334.9	3.9	357.4	-29.7	-97.8	-11.8
	California	6,750.1	7,136.6	4,345.0	4,945.5	5,650.9	6,722.2	7,996.5	4,163.8	4,821.3	5,424.8	-27.9	859.8	-181.1	-124.2	-226.2
	Colorado	509.1	693.8	576.7	581.7	625.6	508.7	765.3	578.2	579.0	610.4	-0.4	71.5	1.4	-2.7	-15.2
	Idaho	117.9	110.9	19.2	18.6	18.0	117.9	124.7	21.4	20.6	20.0	0.0	13.8	2.3	2.0	2.0
	Montana	105.5	104.2	114.0	111.0	107.8	107.5	107.3	114.8	112.0	109.0	2.0	3.1	0.7	1.1	1.2
	Nevada	1,194.4	1,142.9	845.6	774.8	778.6	1,194.5	1,272.6	849.2	778.1	789.1	0.1	129.7	3.5	3.3	10.6
	New Mexico	408.8	414.3	393.5	390.8	446.5	408.7	424.9	400.9	400.5	458.4	-0.1	10.6	7.4	9.7	11.9
	North Dakota	229.8	229.3	223.4	238.5	232.6	231.6	234.8	223.0	238.7	232.3	1.8	5.5	-0.5	0.2	-0.3
	Oregon	877.9	826.8	656.1	585.9	564.7	877.9	926.3	668.2	600.6	578.6	0.0	99.5	12.0	14.6	13.9
	South Dakota	36.3	35.9	35.8	33.9	37.5	36.3	36.8	35.5	34.0	33.5	0.0	0.9	-0.3	0.1	-4.1
	Utah	230.1	223.8	217.8	211.4	206.8	230.1	223.7	219.0	210.1	206.4	0.0	-0.1	1.2	-1.3	-0.4
	Washington	591.6	731.0	603.8	529.8	512.1	591.3	736.9	593.3	554.6	534.7	-0.4	5.9	-10.5	24.8	22.7
	Wyoming	299.9	296.4	295.8	288.1	285.3	303.7	300.1	296.2	286.5	285.0	3.8	3.7	0.5	-1.6	-0.3
WRAP Total		14,900.6	15,353.8	10,836.1	10,999.7	11,813.0	14,883.2	16,915.1	10,643.0	10,827.9	11,616.9	-17.3	1,561.4	-193.1	-171.9	-196.0
CAIR Plus Policy States		54,006.6	56,372.3	43,392.9	40,774.1	41,540.3	54,062.9	64,529.1	42,664.6	40,876.5	41,821.7	56.3	8,156.8	-728.3	102.4	281.4
National		71,683.5	74,667.0	56,390.5	53,755.4	55,245.1	71,724.5	85,067.7	55,493.0	53,794.2	55,477.4	41.0	10,400.7	-897.5	38.8	232.3

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.8: State Level Total Production Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	1,347.2	1,388.4	1,105.9	1,172.0	1,288.5	1,322.4	1,663.0	1,137.3	1,198.7	1,277.8	-24.8	274.6	31.4	26.7	-10.7
	Delaware	219.3	221.6	246.2	251.0	264.9	216.9	226.9	210.1	171.9	190.0	-2.4	5.3	-36.1	-79.2	-75.0
	District of Columbia	16.8	20.6	31.7	82.1	109.4	16.9	21.1	49.7	86.3	102.2	0.1	0.5	18.0	4.2	-7.2
	Maine	719.9	706.5	400.0	417.7	446.0	710.2	703.6	408.0	444.8	456.5	-9.7	-3.0	8.1	27.1	10.5
	Maryland	1,202.6	1,306.6	1,497.8	2,184.0	2,547.0	1,218.3	1,328.3	1,750.7	2,243.4	2,453.2	15.6	21.7	253.0	59.4	-93.8
	Massachusetts	3,325.5	3,134.9	2,601.7	2,350.3	2,497.5	3,332.3	3,260.2	2,598.2	2,417.8	2,585.8	6.8	125.3	-3.5	67.5	88.4
	New Hampshire	476.1	570.5	667.8	732.8	804.0	486.3	586.2	640.1	734.6	772.4	10.2	15.7	-27.7	1.8	-31.6
	New Jersey	1,763.5	1,821.4	1,754.7	1,738.7	1,887.5	1,759.2	2,206.6	1,737.2	1,806.9	2,039.0	-4.3	385.2	-17.5	68.2	151.4
	New York	4,784.0	4,800.2	4,693.6	4,909.6	5,114.7	4,827.8	5,194.5	4,832.3	4,980.0	5,316.4	43.8	394.3	138.7	70.4	201.7
	Pennsylvania	5,159.8	5,414.5	5,348.8	5,311.7	5,367.7	5,230.6	6,123.6	5,280.0	5,386.3	5,563.3	70.8	709.1	-68.8	74.6	195.6
	Rhode Island	162.2	351.6	116.1	138.5	157.1	164.6	387.3	120.8	143.7	152.1	2.4	35.7	4.7	5.2	-5.0
	Vermont	160.7	161.6	202.6	216.5	230.0	163.3	163.8	200.7	220.1	225.1	2.6	2.2	-1.8	3.6	-4.9
MANE-VU Total		19,337.5	19,898.4	18,666.9	19,505.1	20,714.4	19,448.7	21,865.2	18,965.2	19,834.6	21,133.8	111.2	1,966.8	298.3	329.5	419.4
LADCO	Illinois	4,147.6	4,136.3	4,381.3	4,591.8	5,485.4	4,175.0	4,132.7	4,411.8	4,678.6	5,556.0	27.3	-3.7	30.5	86.7	70.7
	Indiana	2,619.9	2,796.4	2,781.3	2,993.8	2,954.7	2,648.3	3,065.4	2,904.4	3,207.2	3,379.2	28.5	269.0	123.1	213.3	424.5
	Michigan	2,801.9	2,912.5	2,758.8	3,059.1	3,900.6	2,810.8	3,302.1	3,017.6	3,289.1	3,572.2	8.9	389.6	258.8	230.0	-328.4
	Ohio	3,735.4	4,142.0	4,385.5	4,609.5	4,619.2	3,780.2	4,363.3	4,248.7	4,707.2	4,886.2	44.8	221.3	-136.8	97.7	267.0
	Wisconsin	1,410.2	1,431.4	1,483.3	1,594.0	1,742.3	1,440.7	1,509.2	1,542.0	1,680.0	1,870.8	30.5	77.8	58.7	86.0	128.5
LADCO Total		14,715.0	15,418.6	15,790.2	16,848.2	18,702.1	14,855.0	16,372.7	16,124.5	17,562.0	19,264.4	140.1	954.1	334.3	713.8	562.3
VISTAS	Alabama	3,577.1	3,878.8	3,708.1	3,969.3	4,348.8	3,570.6	4,556.2	3,915.6	4,022.1	4,498.1	-6.4	677.4	207.5	52.9	149.3
	Florida	7,908.1	7,996.4	7,399.0	8,079.4	8,774.7	7,908.4	9,061.2	7,361.4	8,317.4	8,828.2	0.3	1,064.7	-37.7	238.0	53.5
	Georgia	4,151.0	4,387.6	3,860.7	4,805.1	5,554.2	4,130.0	4,484.8	4,472.1	5,024.2	5,855.2	-20.9	97.2	611.4	219.1	301.0
	Kentucky	1,838.6	1,862.3	1,946.7	2,118.8	2,188.4	1,845.8	1,801.4	2,041.3	2,300.0	2,383.2	7.2	-60.9	94.6	181.1	194.8
	Mississippi	1,249.2	1,364.6	1,131.8	1,449.8	1,633.9	1,248.8	2,140.6	1,279.0	1,474.2	1,662.1	-0.4	776.0	147.2	24.4	28.2
	North Carolina	2,927.7	2,804.4	3,362.7	3,807.0	4,251.9	2,903.5	2,892.3	3,448.5	3,837.0	4,229.9	-24.2	87.8	85.8	30.1	-22.1
	South Carolina	2,374.7	2,563.2	2,846.1	3,133.3	3,533.1	2,361.9	2,828.2	2,920.9	3,207.1	3,686.3	-12.9	265.0	74.8	73.8	153.2
	Tennessee	1,661.8	1,691.3	1,811.2	1,796.3	1,902.1	1,642.0	1,560.5	1,864.9	1,947.0	1,959.9	-19.8	-130.8	53.7	150.8	57.9
	Virginia	1,909.2	2,356.4	2,414.2	2,680.1	3,021.9	1,908.7	2,463.7	2,441.8	2,723.1	3,054.2	-0.6	107.3	27.6	42.9	32.3
	West Virginia	1,880.1	1,912.5	2,108.0	2,315.6	2,351.3	1,928.9	1,967.1	2,154.7	2,395.7	2,495.2	48.8	54.6	46.7	80.1	143.9
VISTAS Total		29,477.4	30,817.5	30,588.5	34,154.7	37,560.2	29,448.6	33,755.9	31,900.0	35,247.7	38,652.3	-28.8	2,938.4	1,311.5	1,093.1	1,092.1
CENRAP	Arkansas	1,453.8	1,662.8	1,603.6	1,713.7	1,857.4	1,458.9	2,239.3	1,552.5	1,725.7	1,884.7	5.1	576.5	-51.1	12.0	27.3
	Iowa	977.6	1,048.0	1,014.5	1,022.7	1,093.2	994.4	1,213.3	1,055.7	1,078.1	1,116.2	16.8	165.4	41.2	55.5	23.0
	Kansas	896.4	894.0	890.8	956.2	1,077.4	894.4	947.4	898.9	952.8	984.3	-2.1	53.5	8.0	-3.3	-93.0
	Louisiana	1,690.2	1,743.3	1,679.8	1,826.5	2,148.0	1,762.3	2,312.9	1,728.8	1,839.8	2,174.2	72.1	569.6	48.9	13.3	26.2

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
	Minnesota	1,110.8	1,143.3	1,105.8	1,090.6	1,092.4	1,115.1	1,141.4	1,138.8	1,156.4	1,150.1	4.3	-1.9	32.9	65.8	57.7
	Missouri	1,520.9	1,626.1	1,656.3	1,768.2	2,001.8	1,520.2	1,572.9	1,671.5	1,730.7	1,970.5	-0.6	-53.2	15.1	-37.6	-31.3
	Nebraska	612.7	620.4	614.9	678.6	672.7	614.4	623.9	616.6	681.0	673.2	1.8	3.6	1.8	2.4	0.5
	Oklahoma	2,477.0	2,651.6	2,220.1	2,219.9	2,327.9	2,477.8	3,284.6	2,234.9	2,337.4	2,506.0	0.8	632.9	14.8	117.5	178.1
	Texas	13,924.8	14,165.7	12,215.7	12,245.8	13,464.5	13,945.9	15,450.9	12,445.1	12,601.0	13,694.0	21.1	1,285.2	229.4	355.3	229.5
CENRAP Total		24,664.2	25,555.2	23,001.6	23,522.2	25,735.3	24,783.4	28,786.7	23,342.6	24,103.1	26,153.3	119.2	3,231.5	341.0	580.8	418.0
WRAP	Arizona	4,461.7	4,326.5	3,774.7	3,555.8	4,132.5	4,446.0	4,664.2	3,799.9	3,556.4	4,223.0	-15.7	337.8	25.2	0.6	90.5
	California	9,562.6	9,975.4	7,393.3	8,753.4	9,752.2	9,594.0	10,897.9	7,211.2	8,582.0	9,474.6	31.4	922.5	-182.1	-171.4	-277.6
	Colorado	799.5	993.2	880.3	960.9	1,074.3	798.0	1,064.3	880.7	956.7	1,068.8	-1.5	71.1	0.4	-4.2	-5.5
	Idaho	178.4	171.4	143.3	142.7	142.1	178.4	185.2	154.5	153.6	153.0	0.0	13.8	11.3	11.0	10.9
	Montana	296.0	301.0	351.2	348.1	350.0	298.0	304.3	357.2	354.5	356.8	2.1	3.2	6.1	6.4	6.8
	Nevada	1,471.5	1,423.5	1,217.0	1,165.8	1,272.3	1,471.6	1,553.4	1,239.5	1,199.5	1,313.4	0.1	130.0	22.5	33.7	41.1
	New Mexico	667.3	673.1	749.3	765.4	922.9	667.1	683.8	769.1	783.1	961.3	-0.1	10.7	19.9	17.7	38.4
	North Dakota	466.9	466.7	465.9	532.0	527.2	461.4	465.9	459.1	504.7	519.5	-5.5	-0.9	-6.8	-27.3	-7.8
	Oregon	1,204.9	1,153.8	1,372.0	1,301.8	1,280.5	1,204.9	1,253.3	1,434.4	1,366.8	1,344.8	0.0	99.5	62.4	65.0	64.3
	South Dakota	85.9	85.5	85.4	104.7	110.6	86.6	87.2	85.9	105.8	106.6	0.7	1.6	0.4	1.2	-4.0
	Utah	480.8	474.6	468.6	464.0	493.8	480.8	474.4	469.8	462.7	493.6	0.0	-0.1	1.2	-1.3	-0.2
	Washington	1,335.7	1,478.7	2,082.1	2,033.2	2,015.5	1,335.3	1,483.7	2,164.6	2,153.8	2,133.9	-0.4	5.0	82.5	120.5	118.4
	Wyoming	645.4	641.9	649.5	641.8	691.2	649.4	645.7	650.1	640.4	692.8	3.9	3.8	0.6	-1.4	1.6
WRAP Total		21,656.5	22,165.3	19,632.4	20,769.5	22,765.1	21,671.5	23,763.4	19,676.1	20,820.0	22,842.1	15.0	1,598.1	43.6	50.5	76.9
CAIR Plus Policy States		84,208.1	87,523.7	84,321.4	90,175.5	98,634.0	84,549.2	95,924.6	86,582.0	92,776.0	101,040.3	341.1	8,400.9	2,260.6	2,600.6	2,406.2
National		109,850.7	113,855.0	107,679.7	114,799.8	125,477.2	110,207.3	124,543.9	110,008.4	117,567.4	128,045.9	356.6	10,688.9	2,328.8	2,767.6	2,568.7

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

ATTACHMENT CC

The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region

The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description

Prepared for the Ozone Transport Commission

Prepared by NESCAUM
Boston, MA

Final
November 2, 2006

Contributing Authors

Tom Downs, Maine DEP
Iyad Kheirbek, NESCAUM
Gary Kleiman, NESCAUM
Paul Miller, NESCAUM
Leah Weiss, NESCAUM

Acknowledgements

NESCAUM thanks the U.S. EPA's support of the Mid-Atlantic/Northeast Visibility Union Regional Organization whose work has provided the foundational basis of this report.

NESCAUM also thanks the following people for their comments and input during the development of this report:

John Graham, NESCAUM
Kurt Kebschull, Connecticut Department of Environmental Protection
Tonalee Key, New Jersey Department of Environmental Protection
Mohammed A. Majeed, Delaware Department of Natural Resources and Environmental Conservation
David Wackter, Connecticut Department of Environmental Protection
Susan Wierman, MARAMA
Mike Woodman, Maryland Department of the Environment
Martha Webster, Maine Department of Environmental Protection
Jung-Hun Woo, NESCAUM

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Executive Summary

Scientific evidence has established a solid link between cardiac and respiratory health risks and transient exposure to ambient fine particle pollution. The same fine particles that are capable of penetrating deep into the lungs are also in the size range that is most efficient at absorbing and scattering visible light, thus impairing visibility. The emission sources, atmospheric chemistry, and meteorological phenomena that influence ambient concentrations of fine particle pollution can act on scales that range from hundreds to thousands of kilometers. Fine particles are not exclusively a secondary pollutant; primary fine particle pollution from local sources can have a significant effect on ambient concentrations in some locations. Fine particles are also not exclusively a summertime pollutant. There are important differences between the meteorological and chemical dynamics that are responsible for high fine particle levels during summer and winter.

In 1997, the U.S. Environmental Protection Agency (USEPA) issued a national ambient air quality standard (NAAQS) for fine particles with an aerodynamic diameter of 2.5 micrometers or less. In 1999, the USEPA followed up with the Regional Haze Rule that enforces a national visibility goal laid out in the Clean Air Act. This will ultimately restore natural visibility to 156 national parks and wilderness areas across the country (called "Class I" areas). To address these Clean Air Act requirements, states will have to develop State Implementation Plans (SIPs) detailing their approaches for reducing fine particle pollution to meet the health-based fine particle NAAQS. They also must develop plans that address the degradation of visibility that exists in various parts of the Northeast (referred to as the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region). As part of this process, the USEPA urges states to include in their SIPs a conceptual description of the pollution problem in their nonattainment and Class I areas. This document provides the conceptual description of the fine particulate and regional haze problems in the MANE-VU states consistent with the USEPA's guidance.

Scientific studies of the regional fine particle problem have uncovered a rich complexity in the interaction of meteorology and topography with fine particle formation and transport. Large scale high pressure systems covering hundreds of thousands of square miles are the source of classic severe fine particle episodes in the eastern United States, particularly in summer. These large, synoptic scale systems create particularly favorable conditions for the oxidation of sulfur dioxide (SO_2) emissions to various forms of sulfate which, in turn, serves to form – or is incorporated into – fine particles that are subsequently transported over large distances. These synoptic scale systems move from west to east across the United States, bringing air pollution emitted by large coal-fired power plants and other sources located outside MANE-VU into the region. This then adds to the pollution burden within MANE-VU on days when MANE-VU's own air pollution sources are themselves contributing to poor air quality. At times, the high pressure systems may stall over the East for days, creating particularly intense fine particle episodes.

In the winter, temperature inversions occur that are effective at concentrating local primary particle emissions at the surface overnight and during early morning hours. This pollution can then be mixed into regionally transported particle pollution (aloft) later in the morning when convection is restored. Additionally, the lower temperature in the winter can shift the chemical equilibrium in the atmosphere slightly toward the production of nitrate particle pollution relative to sulfate formation. As a result, nitrate can become a significant fraction of measured fine particle mass in parts of the eastern U.S. during winter months.

Primary and secondary emissions of carbon-containing compounds (e.g., diesel exhaust, biogenic organic carbon emissions, and anthropogenic volatile organic compound emissions) all contribute to a significant presence of carbonaceous aerosol across the MANE-VU region, which can vary from urban to rural locations and on a seasonal basis. In addition, short range pollution transport exists, with primary and precursor particle pollutants pushed by land, sea, mountain, and valley breezes that can selectively affect relatively local areas. With the knowledge of the different emission sources, transport scales, and seasonal meteorology in various locations adjacent to and within MANE-VU, a conceptual picture of fine particle pollution and its impacts emerges.

The conceptual description that explains elevated regional $PM_{2.5}$ peak concentrations in the summer differs significantly from that which explains the largely urban peaks observed during winter. On average, summertime concentrations of sulfate in the northeastern United States are more than twice that of the next most important fine particle constituent, organic carbon (OC), and more than four times the combined concentration of nitrate and black carbon (BC) constituents. Episodes of high summertime sulfate concentrations are consistent with stagnant meteorological flow conditions upwind of the MANE-VU region and the accumulation of airborne sulfate (via atmospheric oxidation of SO_2) followed by long-range transport of sulfur emissions from industrialized areas within and outside the region.

National assessments have indicated that in the winter, sulfate levels in urban areas are higher than background sulfate levels across the eastern U.S., indicating that the local urban contribution to wintertime sulfate levels is significant relative to the regional sulfate contribution from long-range transport. A network analysis for the winter of 2002 suggests that the local enhancement of sulfate in urban areas of the MANE-VU region ranges from 25 to 40% and that the long-range transport component of $PM_{2.5}$ sulfate is still the dominant contributor in most eastern cities.

In the winter, urban OC and sulfate each account for about a third of the overall $PM_{2.5}$ mass concentration observed in Philadelphia and New York City. Nitrate also makes a significant contribution to urban $PM_{2.5}$ levels observed in the northeastern United States during the winter months. Wintertime concentrations of OC and nitrate in urban areas can be twice the average regional concentrations of these pollutants, indicating the importance of local source contributions. This is likely because winter conditions are more conducive to the formation of local inversion layers which prevent vertical mixing. Under these conditions, emissions from tailpipe, industrial and other local sources become concentrated near the Earth's surface, adding to background pollution levels associated with regionally transported emissions.

From this conceptual description of fine particle pollution formation and transport into and within MANE-VU, air quality planners need to develop an understanding of what it will take to clean the air in the MANE-VU region. Every air pollution episode is unique in its specific details. The relative influences of the transport pathways and local emissions vary by hour, day, and season. The smaller scale weather patterns that affect pollution accumulation and its transport underscore the importance of local (in-state) controls for SO_2, nitrogen oxides (NO_X) and volatile organic compound (VOC) emissions. Larger synoptic scale weather patterns, and pollution patterns associated with them, support the need for SO_2 and NO_X controls across the broader eastern United States. Studies and characterizations of nocturnal low level jets also support the need for local and regional controls on SO_2 and NO_X sources as locally generated and transported pollution can both be entrained in low level jets formed during nighttime hours. The presence of land, sea, mountain, and valley breezes indicate that there are unique aspects of pollution accumulation and transport that are area-specific and will warrant policy responses at the local and regional levels beyond a one-size-fits-all approach.

The mix of emission controls is also important. Regional fine particle formation is primarily due to SO_2, but NO_X is also important because of its influence on the chemical equilibrium between sulfate and nitrate pollution during winter. While the effect of reductions in anthropogenic VOCs is less well characterized at this time, secondary organic aerosol (SOA) is a major component of fine particles in the region and reductions in anthropogenic sources of OC may have a significant effect on fine particle levels in urban nonattainment areas. Therefore, a combination of localized NO_X and VOC reductions in urban centers with additional SO_2 and NO_X reductions from across a larger region will help to reduce fine particles and precursor pollutants in nonattainment areas as well improve visibility across the entire MANE-VU region.

1. INTRODUCTION

1.1. Background

Fine particle pollution is a persistent public health problem in the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region. Because of its physical structure, fine particulate matter ($PM_{2.5}$) can bypass conductive airways and deliver exogenous materials, such as reactive organic chemicals that adsorb onto the particle core, into the deep lung.[1] Studies of particulate matter (PM) in urban areas have found associations of short- (daily) and long-term (annual and multiyear) exposure to airborne PM as well as $PM_{2.5}$ with cardiopulmonary health outcomes. These effects include increased symptoms, hospital admissions and emergency room visits, and premature death (Pope *et al.* 2004).

In addition to health implications, visibility impairment in the eastern United States is largely due to the presence of light-absorbing and light-scattering fine particles in the atmosphere. The United States Environmental Protection Agency (USEPA) has identified visibility impairment as the best understood of all environmental effects of air pollution (Watson, 2002). A long-established physical and chemical theory relates the interaction of particles and gases in the atmosphere with the transmission of visual information along a sight path from object to observer.

The Clean Air Act requires states that have areas designated "nonattainment" of the fine particle national ambient air quality standard (NAAQS) to submit State Implementation Plans (SIPs) demonstrating how they plan to attain the fine particle NAAQS.[2] The Clean Air Act also contains provisions for the restoration and maintenance of visibility in 156 federal Class I areas.[3] SIPs for dealing with visibility impairment (or regional haze) must include a long-term emissions management strategy aimed at reducing fine particle pollution in these rural areas.

As part of the SIP process for both of these air quality issues, the USEPA urges states to include a conceptual description of the pollution problem. The USEPA has provided guidance on developing a conceptual description, which is contained in Chapter 11 of the document "Guidance on the Use of Models and Other Analyses for

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[1] $PM_{2.5}$ or "fine particles" refer to those particles with a diameter ≤ 2.5 micrometers (μm).

[2] The 1997 $PM_{2.5}$ NAAQS includes a requirement that the three-year average of yearly annual average $PM_{2.5}$ design values must be below 15 $\mu g/m^3$ and a requirement that the three-year average of the 98th percentile 24-hour average concentration must be below 65 $\mu g/m^3$. In October 2006, the USEPA acted to change the daily standard (98th percentile value based on valid 24-hour average concentrations measured at a site) from 65 to 35 $\mu g/m^3$.

[3] The Class I designation applies to national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence prior to 1977. In the MANE-VU area, this includes: Acadia National Park, Maine; Brigantine Wilderness (within the Edwin B. Forsythe National Wildlife Refuge), New Jersey; Great Gulf Wilderness, New Hampshire; Lye Brook Wilderness, Vermont; Moosehorn Wilderness (within the Moosehorn National Wildlife Refuge), Maine; Presidential Range – Dry River Wilderness, New Hampshire; and Roosevelt Campobello International Park, New Brunswick.

Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze" (EPA-Draft 3.2, September 2006) (Appendix A of this report reproduces Chapter 11 of the USEPA guidance document). This report provides the MANE-VU states with the basis for their conceptual descriptions, consistent with the USEPA's guidance. In the guidance, the USEPA recommends addressing 13 questions related to $PM_{2.5}$ and eight questions related to visibility to help define the problem in a nonattainment or Class I area. This report addresses these questions, as well as provides some in-depth data and analyses that can assist states in developing conceptual descriptions tailored to their specific areas.

1.2. PM Formation

Fine particles directly emitted into the atmosphere are called "primary" fine particles, and they come from both natural and human sources. These fine particles commonly include unburned carbon particles directly emitted from high-energy processes such as combustion, and particles emitted as combustion-related vapors that condense within seconds of being exhausted to ambient air. Combustion sources include motor vehicles, power generation facilities, industrial facilities, residential wood burning, agricultural burning, and forest fires.

Fine particles are also comprised of "secondary" fine particles, which are formed from precursor gases reacting in the atmosphere or through the addition of PM to pre-existing particles. Although direct nucleation from the gas phase is a contributing factor, most secondary material accumulates on pre-existing particles in the 0.1 to 1.0 micrometer (μm) range and typically account for a significant fraction of the fine PM mass. Examples of secondary particle formation include the conversion of sulfur dioxide (SO_2) to sulfuric acid (H_2SO_4) droplets that further react with ammonia (NH_3) to form various sulfate particles (e.g., ammonium sulfate $(NH_4)_2SO_4$, ammonium bisulfate (NH_4HSO_4), and letovicite ($(NH_4)_3H(SO_4)_2$). The dominant source of SO_2 emissions in the eastern U.S. is fossil fuel combustion, primarily at coal-fired power plants and industrial boilers. Similarly, secondary $PM_{2.5}$ is created by the conversion of nitrogen dioxide (NO_2) to nitric acid (HNO_3) which reacts further with ammonia to form ammonium nitrate (NH_4NO_3) particles. Nitrate particles are formed from the NO_X emitted by power plants, automobiles, industrial boilers, and other combustion sources. Nitrate production in the northeastern U.S. is ammonia-limited and controlled by the availability of sulfate and temperature, especially along the East Coast.[4] While human sources account for most nitrate precursors in the atmosphere, there are some natural sources, including lightning, biological and abiological processes in soils, and stratospheric intrusion. Large sources of ammonia arise from major livestock production and fertilizer application throughout the Midwest, Gulf Coast, mid-Atlantic, and southeastern United States, in addition to the sources of ammonia associated with human activities.

The carbon fraction of fine PM may refer to black carbon (BC) and primary organic and/or secondary organic carbon (OC). Most black carbon is primary, which is

[4] Ammonia reacts preferentially with sulfuric acid, and if sufficient excess ammonia is available, it can then combine with nitric acid to form particulate nitrate.

also sometimes referred to as elemental carbon (EC) or soot. Black carbon is the light-absorbing carbonaceous material in atmospheric particles caused by the combustion of diesel, wood, and other fuels. Organic carbon includes both primary emissions and secondary organic PM in the atmosphere. Secondary organic particles are formed by reactions involving volatile organic compounds (VOCs), which yield compounds with low saturation vapor pressures that nucleate or condense on existing particles at ambient temperature. Organic carbon in both the gas and solid phase is emitted by automobiles, trucks, and industrial processes, as well as by many types of vegetation. The relative amounts of organic carbon from different sources remain highly uncertain, and data are needed to be able to assess the relative contribution of primary versus secondary and anthropogenic versus biogenic production.

1.3. PM Impacts on Visibility

Under natural atmospheric conditions, the view in the eastern United States would extend about 60 to 80 miles (100 to 130 kilometers) (Malm, 2000). Unfortunately, views of such clarity have become a rare occurrence in the East. As a result of man-made pollution, the average visual range in the eastern half of the country has diminished to about 15-30 miles, approximately one-third the visual range that would be observed under unpolluted natural conditions.

In general, the ability to see distant features in a scenic vista is determined less by the amount of light reaching the observer than by the contrast between those features and their surroundings. For example, the illumination of a light bulb in a greenhouse is barely discernible on a sunny day but would be highly visible at night. Similarly, a mountain peak is easily seen if it appears relatively dark against the sunlit sky. If, on the other hand, a milky haze "fills" the space between the observer and the mountain peak, the contrast between the mountain and its background is diminished as both take on a similar hue (Figure 1-1).

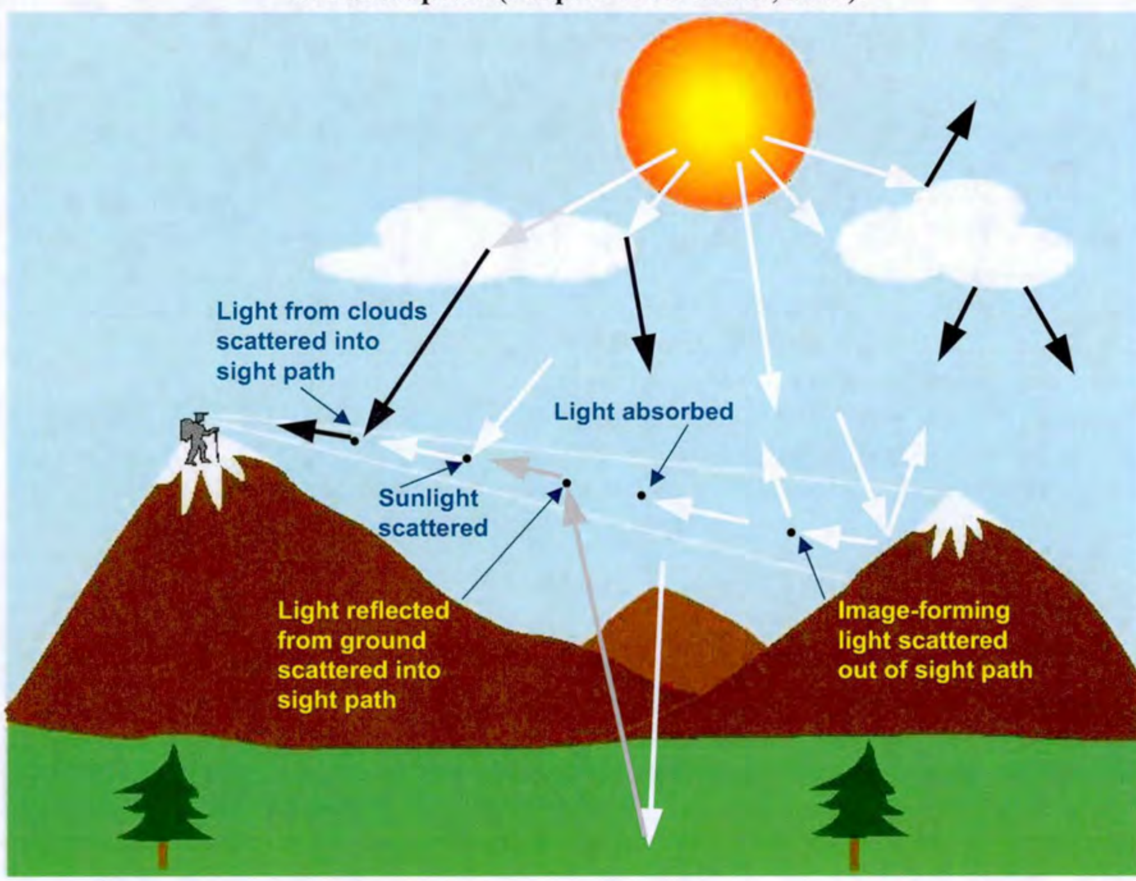
Figure 1-1. View of a good visibility day (left) and a poor visibility day (right) at Acadia National Park, Maine in June 2003.

Source: CAMNET, http://www.hazecam.net

In simple terms, this hazy effect occurs when small particles and certain gaseous molecules in the atmosphere absorb or scatter visible light, thereby reducing the amount of visual "information" that reaches the observer. This occurs to some extent even under natural conditions, primarily as a result of the light scattering effect of individual air molecules (known as Rayleigh scattering[5]) and of naturally occurring aerosols.[6] The substantial visibility impairment caused by manmade pollution, however, is almost entirely attributable to the increased presence of fine particles in the atmosphere.[7]

Figure 1-2 presents a simplified schematic of the way such small particles interact with packets of light or "photons" as they travel from a distant object to an observer. Along the way, particles suspended in the air can deflect or scatter some of the photons out of the sight path. Intervening particles can also absorb photons, similarly removing them from the total amount of light reaching the observer.

Figure 1-2. Schematic of visibility impairment due to light scattering and absorption (adapted from Malm, 2000).



[5] Because air molecules more effectively scatter light of short wavelengths (i.e., blue light), Rayleigh scattering explains the blue color of the sky.

[6] Atmospheric aerosol is a more general term for fine particles suspended in the atmosphere and refers to any particle (solid or liquid) that is suspended in the atmosphere.

[7] The only light-absorbing *gaseous* pollutant present in the atmosphere at significant concentrations is nitrogen dioxide (NO_2). However, the contribution of NO_2 to overall visibility impacts in the Northeast is negligible and hence its effects are not generally included in this discussion or in standard calculations of visibility impairment.

At the same time, particles in the air can scatter light into the sight path, further diminishing the quality of the view. The extraneous light can include direct sunlight and light reflected off the ground or from clouds. Because it is not coming directly from the scenic element, this light contains no visual information about that element. When the combination of light absorption and light scattering (both into and out of the sight path) occurs in many directions due to the ubiquitous presence of small particles in the atmosphere, the result is commonly described as "haze."

1.4. $PM_{2.5}$ Design Values in the MANE-VU Region

SIP developers use monitoring data in several important ways to support SIP activities. This section as well as Section 1.5 present measurements from the FRM and IMPROVE network needed in establishing SIP requirements. Following USEPA guidance (40CFR Part 50, Appendix N; USEPA, 2003a; USEPA, 2003b), we use these data to preview the Design Values and Baseline Conditions that SIP developers must consider for each nonattainment area and Class I area.

The current annual fine particle National Ambient Air Quality Standard was established in 1997 at 15 $\mu g/m^3$. To meet this standard, the 3-year average of a site's annual mean concentration must not be greater than this level. The current daily standard was set at 65 $\mu g/m^3$ at the 98^{th} percentile level. To meet this standard, the 98^{th} percentile value (of valid measurements recorded at a site) must not be greater than this level. No counties in MANE-VU have been designated nonattainment for the daily standard, however, the USEPA has revised the NAAQS with respect to the 24-hr average concentrations and states will have to comply with the new standard (35 $\mu g/m^3$ at the 98^{th} percentile level) within five years of designations (expected in 2010). Fine particle data from the USEPA's Air Quality System (AQS) database for years 2002 through 2004 were used to determine the attainment status of monitoring sites in MANE-VU.

Table 1-1 shows a summary of areas found to exceed the annual standard (no areas exceed the daily standard). As tabulated, 12 areas fail to achieve the annual standard, with design values ranging from 15.1 to 20.4 $\mu g/m^3$. The nonattainment areas are concentrated in Pennsylvania and the coastal urban corridor. Sulfates and organic carbon represent the largest contributors to these high fine particle levels.

Table 1-1. 2004 $PM_{2.5}$ Design Value for Nonattainment Areas in MANE-VU

State(s)	Nonattainment Area	2004 Annual Design Value	2004 24-hr Design Value
MD	Baltimore	16.3	41
PA	Harrisburg-Lebanon-Carlisle	15.4	41
PA	Johnstown	15.3	40
PA	Lancaster	16.8	42
PA	Liberty-Clairton	20.4	65
MD	Martinsburg, WV-Hagerstown	16.1	39
NY-NJ-CT	New York-N. New Jersey-Long Island	16.8	50
PA-NJ-DE	Philadelphia-Wilmington	15.4	39
PA	Pittsburgh-Beaver Valley	16.5	45
PA	Reading	16.1	42
DC-MD-VA	Washington, DC	15.1	42
PA	York	16.9	43

1.5. Regional haze baseline conditions

The Regional Haze Rule requires states and tribes to submit plans that include calculations of current and estimated baseline and natural visibility conditions. They will use monitoring data from the IMPROVE program as the basis for these calculations. Table 1-2 and Table 1-3 present the five-year average[8] of the 20 percent worst day mass concentrations and 20 percent best day mass concentrations respectively in six Class I areas. Five of these areas are in MANE-VU and one (Shenandoah) is nearby but located in a neighboring regional planning organization (RPO) region.[9] Table 1-4 and Table 1-5 give the corresponding worst day and best day contributions to particle extinction for the six Class I areas. Each of these tables show the relative percent contribution for all six Class I sites. Sulfate and organic carbon dominate the fine mass, with sulfate even more important to particle extinction.

To guide the states in calculating baseline values of reconstructed extinction and for estimating natural visibility conditions, the USEPA released two documents in the fall of 2003 outlining recommended procedures (USEPA 2003a; USEPA 2003b). Recently, the IMPROVE Steering Committee endorsed an alternative method for the calculation of these values. The IMPROVE alternative methods were used, to create Table 1-6, which provides detail on the uniform visibility goals for the 20 percent worst conditions at the six Class 1 areas.

[8] Great Gulf calculations are based on four years of data (2001-2004).

[9] Note that values presented for Shenandoah, a Class I area in the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) region, are for comparative purposes only. VISTAS will determine uniform rates of progress for areas within its region.

The first column of data in Table 1-6 gives the alternative proposed natural background levels for the worst visibility days at these six sites. MANE-VU has decided to use this approach, at least initially, for 2008 SIP planning purposes (NESCAUM, 2006). The second column shows the baseline visibility conditions on the 20 percent worst visibility days. These values are based on IMPROVE data from the official five-year baseline period (2000-2004) and again were calculated using the IMPROVE alternative approach. Using these baseline and natural background estimates, we derive the uniform rate of progress shown in the third column.[10] The final column displays the interim 2018 progress goal based on 14 years of improvement at the uniform rate.

Table 1-2. Fine mass and percent contribution for 20 percent worst days

20% Worst-day Fine Mass ($\mu g/m^3$)/% contribution to fine mass					
Site	SO_4	NO_3	OC	EC	Soil
Acadia	6.3/ 56%	0.8/ 7%	3.2/ 28%	0.4/ 4%	0.5/ 5%
Brigantine	11.6/ 56%	1.7/ 8%	5.8/ 28%	0.7/ 3%	1/ 5%
Great Gulf	7.3/ 59%	0.4/ 3%	3.8/ 31%	0.4/ 3%	0.6/ 5%
Lye Brook	8.5/ 58%	1.1/ 7%	3.9/ 27%	0.5/ 3%	0.6/ 4%
Moosehorn	5.7/ 54%	0.7/ 7%	3.4/ 32%	0.4/ 4%	0.4/ 4%
Shenandoah	13.2/ 68%	0.7/ 3%	4.2/ 22%	0.6/ 3%	0.7/ 4%

Table 1-3. Fine mass and percent contribution for 20 percent best days

20% Best-day Fine Mass ($\mu g/m^3$)/% contribution to fine mass					
Site	SO_4	NO_3	OC	EC	Soil
Acadia	0.8/ 42%	0.1/ 6%	0.8/ 41%	0.1/ 5%	0.1/ 6%
Brigantine	1.8/ 43%	0.5/ 11%	1.5/ 35%	0.2/ 6%	0.2/ 5%
Great Gulf	0.7/ 43%	0.1/ 7%	0.7/ 40%	0.1/ 5%	0.1/ 6%
Lye Brook	0.6/ 44%	0.1/ 11%	0.4/ 33%	0.1/ 5%	0.1/ 7%
Moosehorn	0.8/ 37%	0.1/ 6%	1/ 47%	0.1/ 5%	0.1/ 5%
Shenandoah	1.4/ 45%	0.5/ 16%	1/ 29%	0.2/ 5%	0.2/ 5%

[10] We calculate the rate of progress as (baseline – natural background)/60 to yield the annual deciview (dv) improvement needed to reach natural background conditions in 2064, starting from the 2004 baseline.

Table 1-4. Particle extinction and percent contribution for 20 percent worst days

20% Worst-day particle extinction (Mm^{-1}) /% Contribution to particle extinction						
Site	SO_4	NO_3	OC	EC	Soil	CM
Acadia	69.2/ 64%	8/ 7%	11.2/ 10%	4.3/ 4%	0.5/ 0%	1.9/ 2%
Brigantine	127.1/ 66%	15.7/ 8%	24.2/ 13%	7/ 4%	1/ 1%	5.4/ 3%
Great Gulf	76.6/ 68%	3/ 3%	14.4/ 13%	3.9/ 3%	0.6/ 1%	3/ 3%
Lye Brook	87.3/ 67%	9.1/ 7%	15.3/ 12%	4.8/ 4%	0.6/ 0%	1.8/ 2%
Moosehorn	58.5/ 60%	6.4/ 7%	11.9/ 12%	4.4/ 5%	0.4/ 0%	2.1/ 3%
Shenandoah	155.5/ 79%	5.8/ 3%	16.1/ 8%	5.7/ 3%	0.7/ 0%	2.5/ 1%

Table 1-5. Particle extinction and percent contribution for 20 percent best days

20% Best-day particle extinction (Mm^{-1}) /% Contribution to particle extinction						
Site	SO_4	NO_3	OC	EC	Soil	CM
Acadia	6.8/ 28%	1.1/ 4%	2.2/ 9%	0.9/ 4%	0.1/ 0%	0.7/ 6%
Brigantine	14.8/ 35%	3.9/ 9%	4.5/ 11%	2.4/ 6%	0.2/ 1%	3.2/ 11%
Great Gulf	5.8/ 27%	1/ 4%	2/ 9%	0.8/ 4%	0.1/ 0%	0.9/ 8%
Lye Brook	4.4/ 23%	1.2/ 6%	1.3/ 7%	0.6/ 3%	0.1/ 0%	0.5/ 6%
Moosehorn	6.7/ 26%	1.1/ 4%	3.1/ 12%	1/ 4%	0.1/ 0%	1.1/ 8%
Shenandoah	11.2/ 36%	4.2/ 13%	2.9/ 9%	1.6/ 5%	0.2/ 1%	1.1/ 5%

Table 1-6. Natural background and baseline calculations for select Class I areas

Site	20 % Worst Days Natural Background (dv)	20% Worst Days Baseline 2000-04(dv)	Uniform Rate (dv/yr)	Interim Progress Goal 2018 (dv)	20% Best Days Baseline 2000-04(dv)
Acadia	12.54	22.89	0.17	20.47	8.77
Brigantine	12.34	29.01	0.28	25.12	14.33
Great Gulf	12.12	22.82	0.18	20.32	7.66
Lye Brook	11.85	24.44	0.21	21.50	6.37
Moosehorn	12.10	21.72	0.16	19.48	9.15
Dolly Sods	10.45	29.05	0.31	24.71	12.28
James River Face	11.20	29.12	0.30	24.94	14.21
Shenandoah	11.44	29.31	0.30	25.14	10.92

As demonstrated in Table 1-2, the inorganic constituents of fine particles, sulfates and nitrates are the dominant contributors to visibility impairment, accounting for about 80 percent of total particle extinction. Within the MANE-VU sites, the relative split between these two components is ~8 to 1 sulfate to nitrate (at Shenandoah, the average 20 percent worst day contribution of sulfates is even more dominant). Carbonaceous components account for the bulk of the remaining particle extinction, ranging from 12 to nearly 20 percent, mostly in the form of organic carbon. The remaining components add little to the extinction budget on the worst days, with a few percent attributable to coarse mass and around a half percent from fine soil.

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2. A DETAILED LOOK AT FINE PARTICLE POLLUTION AND REGIONAL HAZE IN THE MANE-VU REGION

Developing a conceptual description of fine particle pollution or regional haze requires combining experience and atmospheric-science expertise with multiple data sources and analysis techniques. This includes measured data on ambient pollutant concentrations as well as emission inventory and meteorological data, chemical transport modeling, and observationally based models (NARSTO, 2003). Here, we begin with a conceptual description based on the existing scientific literature and regional data analyses concerning $PM_{2.5}$ and its effect on visibility. This includes numerous review articles and reports on the subject. Subsequent chapters review monitoring data, emissions inventory information, and modeling results to support the conceptual understanding of regional fine particle pollution presented here.

Most past assessments of fine particle pollution and visibility impairment have tended to be national in scope. For purposes of this discussion, we have selectively reviewed the literature in order to present a distinctly eastern U.S. focus. While we already know much about fine particle pollution and visibility impairment and their causes in the MANE-VU region (see NESCAUM, 2001, 2006; NARSTO, 2003; Watson, 2002), significant gaps in understanding remain with respect to the nitrate and organic component of $PM_{2.5}$. While research continues, we have assembled the relevant information that is available to provide an overview of our current understanding of the regional context for $PM_{2.5}$ nonattainment and visibility impairment in the MANE-VU region.

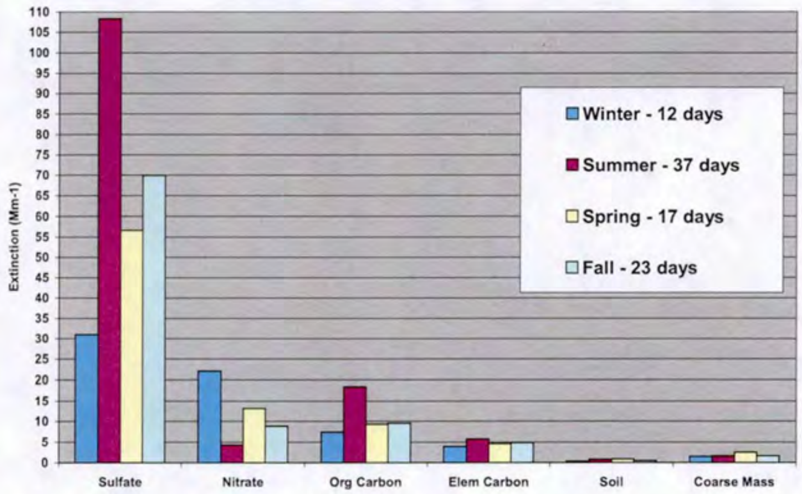
2.1. Chemical composition of particulate matter in the rural MANE-VU region

Sulfate alone accounts for anywhere from one-half to two-thirds of total fine particle mass on high $PM_{2.5}$ days in rural areas of MANE-VU. Even on low $PM_{2.5}$ days, sulfate generally accounts for the largest fraction (40 percent or more) of total fine particle mass in the region (NESCAUM, 2001, 2004b). Sulfate accounts for a major fraction of $PM_{2.5}$, not only in the Northeast but across the eastern United States (NARSTO, 2003).

After sulfate, organic carbon (OC) consistently accounts for the next largest fraction of total fine particle mass. Its contribution typically ranges from 20 to 30 percent of total fine particle mass on the days with the highest levels of $PM_{2.5}$. The fact that the contribution from organic carbon can be as high as 40 percent at the more rural sites on low $PM_{2.5}$ days is likely indicative of the role played by organic emissions from vegetation (so-called "biogenic hydrocarbons").

Relative contributions to overall fine particle mass from nitrate (NO_3), elemental carbon, and fine soil are all smaller (typically under 10 percent), but the relative ordering among the three species varies with location and season. Figure 2-1 below, reflects the difference between nitrate and organic contributions to rural fine particle concentrations during different seasons (monitoring data for additional sites in the MANE-VU region are in Appendix B).

Figure 2-1. Comparison of contributions during different seasons at Lye Brook Wilderness Area on 20% worst visibility (high $PM_{2.5}$) days (2000-2003).

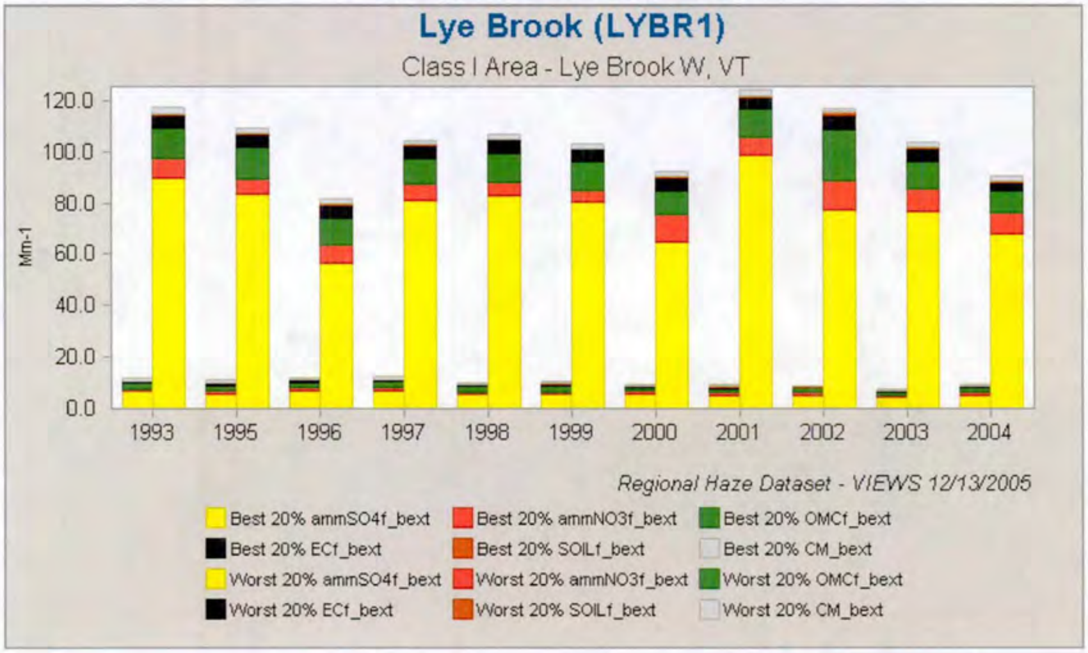


Almost all particle sulfate originates from sulfur dioxide (SO_2) oxidation and typically associates with ammonium (NH_4) in the form of ammonium sulfate ($(NH_4)_2SO_4$). Ninety-five percent of SO_2 emissions are from anthropogenic sources (primarily from fossil fuel combustion), while the majority of ammonium comes from agricultural activities and, to a lesser extent, from transportation sources in some areas (NARSTO, 2003).

Two major chemical pathways produce sulfate from SO_2 in the atmosphere. In the gas phase, production of sulfate involves the oxidation of SO_2 to sulfuric acid (H_2SO_4), ammonium bisulfate (NH_4HSO_4), or ammonium sulfate, depending on the availability of ammonia (NH_3). In the presence of small wet particles (typically much, much smaller than rain drops or even fog), a highly efficient aqueous phase process can oxidize SO_2 to sulfate extremely quickly (~10 percent per hour).

Not only is sulfate the dominant contributor to fine particle mass in the region, it accounts for anywhere from 60 percent to almost 80 percent of the *difference* between fine particle concentrations and extinction on the lowest and highest mass days at rural locations in the northeast and mid-Atlantic states (See Figure 2-2). Notably, at urban locations such as Washington DC, sulfate accounts for only about 40 percent of the difference in average fine particle concentrations for the 20 percent most versus least visibility impaired days (NESCAUM, 2001).

Figure 2-2. Comparison of species contributions on best and worst days at Lye Brook Wilderness Area.



2.2. Rural versus urban chemistry

Contributions to fine particle mass concentrations at rural locations include long-range pollutant transport as well as non-anthropogenic background contributions. Urban areas generally show mean $PM_{2.5}$ levels exceeding those at nearby rural sites. In the Northeast, this difference implies that local urban contributions are roughly 25 percent of the annual mean urban concentrations, with regional aerosol contributing the remaining, and larger, portion (NARSTO, 2003).

This rural versus urban difference in typical concentrations also emerges in a source apportionment analysis of fine particle pollution in Philadelphia (see Chapter 10 of NARSTO, 2003) using two different mathematical models, UNMIX and Positive Matrix Factorization (PMF). This analysis provides additional insight concerning sources of fine particle pollution in urban areas of the densely populated coastal corridor between Washington DC and New England. Specifically, this analysis found the following apportionment of $PM_{2.5}$ mass in the study area:

- Local SO_2 and sulfate: ~ 10 percent
- Regional sulfate: ~ 50 percent
- Residual oil: 4-8 percent
- Soil: 6-7 percent
- Motor vehicles: 25-30 percent

The analysis does not account for biogenic sources, which most likely are embedded in the motor vehicle fraction (NARSTO, 2003). The Philadelphia study suggests that both local pollution from nearby sources and transported "regional" pollution from distant sources contribute to the high sulfate concentrations observed in urban locations along the East Coast on an annual average basis. Summertime sulfate and organic carbon are strongly regional in eastern North America. Typically 75–95 percent of the urban sulfate concentrations and 60–75 percent of the urban OC concentrations arise from cumulative region-wide contributions (NARSTO, 2003). Urban air pollutants are essentially added on top of this regional background. Nitrate plays a noticeably more important role at urban sites compared to northeastern and mid-Atlantic rural monitoring sites, perhaps reflecting a greater contribution from vehicles and other urban pollution sources (NESCAUM, 2001).

It is difficult to discern any significant meaning about the cause of "excess" mass from a single pair of sites. There are many factors that influence the concentrations at a particular site and it is likely that for every pair of sites that shows an urban excess, one could find some pair of locations that might show something similar to an urban "deficit." While paired sites from an urban and a rural location will *typically* show greater concentrations in the urban location and lower levels of pollution in rural areas, great care must be exercised in the interpretation of any two-site analysis such as the comparisons of speciated components of $PM_{2.5}$ presented here. Nonetheless, such comparisons do provide a general feel for the typical chemical composition of $PM_{2.5}$ in the eastern U.S. and the relative differences in chemical composition between rural and more urban locations. More detailed, "network"-wide analyses (e.g., see NESCAUM 2004b; relevant sections are attached in Appendix C to this report) indicate that the results provided are not anomalous of typical urban environments in the MANE-VU region.

Figure 2-3 and Figure 2-4 compare two urban-rural pairs of speciation monitors: the New York nonattainment area (Elizabeth and Chester, New Jersey) and the Boston metropolitan area (Boston and Quabbin Reservoir, Massachusetts). The first three sites are Speciation Trends locations, while the Reservoir site is part of the IMPROVE protocol network.[11]

[11] To provide a more direct comparison of the differences between the urban and rural sites, only those days for which both monitors in a pair had data were used. Four seasonal averages were computed for 2002, with seasons defined as winter (January, February, December), spring (March, April, May), Summer (June, July, August) and Fall (September, October, November). July 7 was excluded from the analysis because the Quebec forest fires affecting the region on that day would have dominated the summertime averages. The major fine particle species categories considered included ammonium sulfate, ammonium nitrate, organic carbon, elemental carbon, and soil mass. The traditional assumptions about these constituents were made; all sulfate was fully neutralized and a multiplier of 1.4 was used to account for mass of organic carbon. An "other $PM_{2.5}$ mass" category was created to delineate the difference between gravimetric mass determined from the Teflon filter and the reconstructed mass sum of the individual mass constituents. Where no "other" mass is graphed, the sum of the species either equaled or exceeded the directly measured mass. No adjustments were made to account for the different operational definitions of carbon between the IMPROVE and STN networks. Average blank corrections were applied to all samples. In the case of New York City, both rural and urban monitors were STN. The Boston pair reflects not only inter-site differences, but also differences in definition of organic and elemental carbon. However, the general interpretation of the data differences remains consistent. Based on current understanding, the rural elemental carbon would be even lower than what is shown on the graph if it were made consistent with the STN definition of EC. Likewise, the organic carbon value would increase slightly for the rural value, as the

Figure 2-3. New York nonattainment area (Elizabeth, NJ) compared to an upwind background site (Chester, NJ)

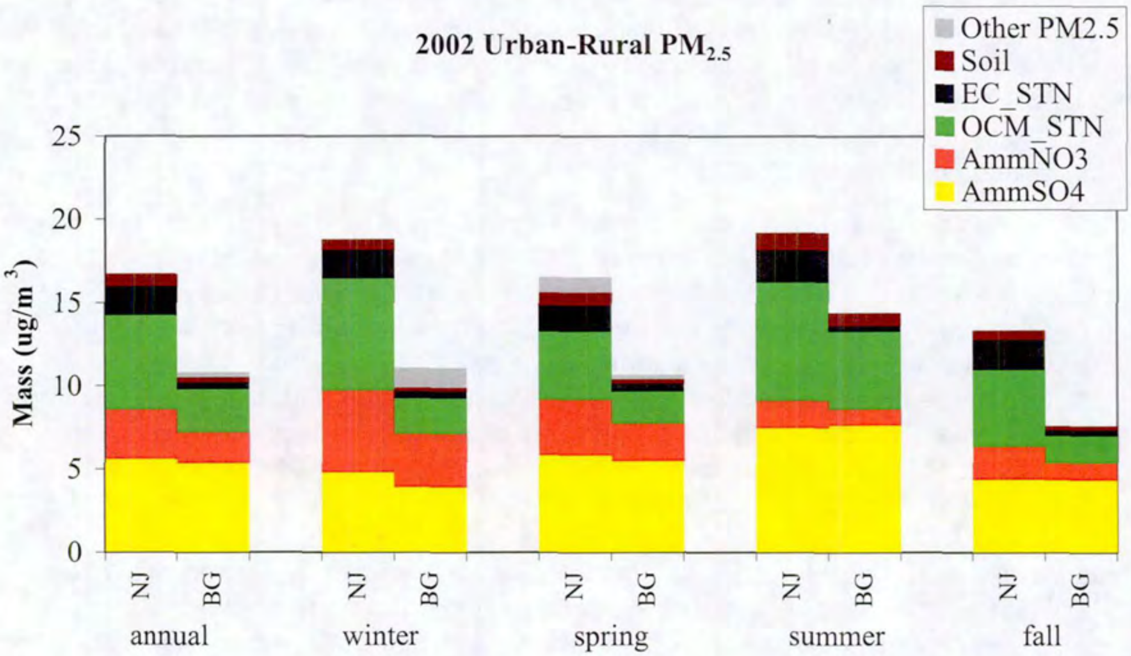
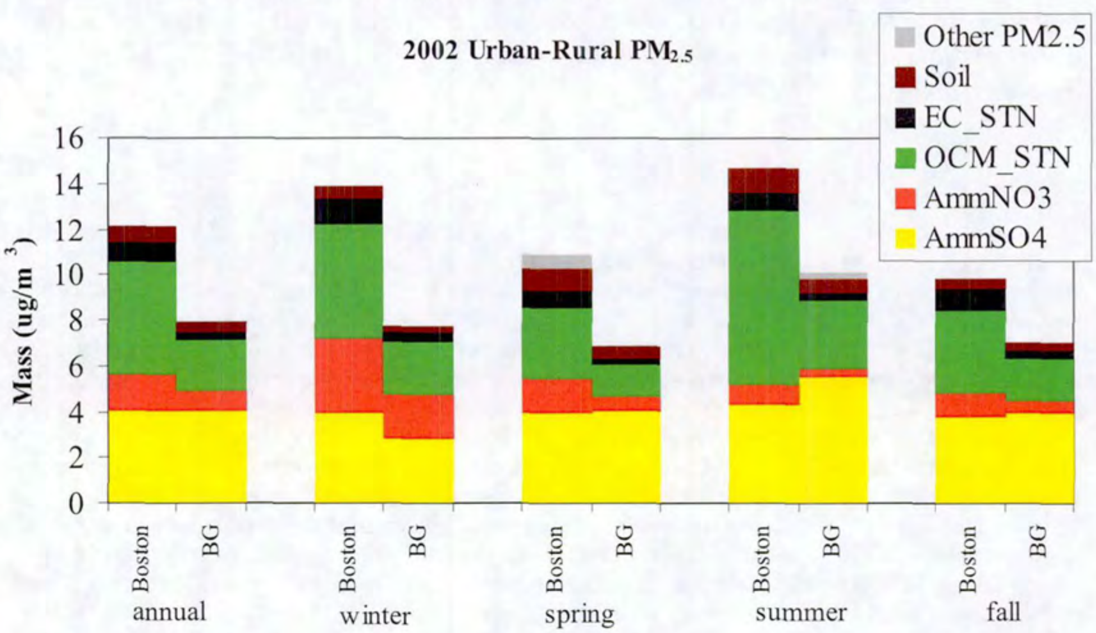


Figure 2-4. Boston urban area (Boston, MA) compared to an upwind background site (Quabbin Reservoir, MA)



EC would be allocated to OC. The urban OC levels are so much greater than those in the rural area that a slight increase in rural OC makes little difference.

The urban-rural differences show consistency for both the New York City nonattainment area and Boston. On an annual scale, the sulfate levels are comparable, with increased mass loading at these urban sites driven primarily by differences in nitrates and carbon with smaller differences in "soil" levels. One interesting aspect of this comparison is the seasonal differences in the urban-rural sulfate split. On an annual basis, sulfate appears to be similar at urban and rural locations (based on these two pair of sites); however, during the colder months, the urban sulfate levels are elevated relative to the rural levels. This behavior is opposite during the summer. During the wintertime, the Northeast urban corridor itself is a substantial source of sulfur emissions. These local emissions can be trapped near the surface during the winter and have a corresponding higher impact on the urban area relative to the rural area.

For both urban and rural areas, the summertime OC levels are significantly greater than wintertime concentrations. Although the oxidation chemistry slows in winter, the cooler temperatures change the phase dynamics, driving more mass into the condensed over the gas phase. This along with more frequent temperature inversions (which limit atmospheric ventilation of the urban boundary layer) can lead to the observed increases in the relative influence of both organic and nitrate levels during winter months. EC, OC, and nitrate all are observed to have higher measured levels in the urban area (but still lower than the comparable summer values measured at the same sites), driven by local sources of these constituents.

2.3. Geographic considerations and attribution of $PM_{2.5}$/haze contributors

In the East, both annual average and maximum daily fine particle concentrations are highest near heavily industrialized areas and population centers. Not surprisingly, given the direct connection between fine particle pollution and haze, the same pattern emerges when one compares measures of light extinction on the most and least visibility impaired days at parks and wilderness areas subject to federal haze regulations in the MANE-VU region (NESCAUM, 2001). An accumulation of particle pollution often results in hazy conditions extending over thousands of square kilometers (km^2) (NARSTO, 2003). Substantial visibility impairment is a frequent occurrence in even the most remote and pristine areas of the MANE-VU region (NESCAUM, 2001).

$PM_{2.5}$ mass declines fairly steadily along a southwest to northeast transect of the MANE-VU region. This decline is consistent with the existence of large fine particle emissions sources (both primary and secondary) to the south and west of MANE-VU. This trend is driven, in large part, by the marked southwest-to-northeast gradient in ambient sulfate concentrations during three seasons of the year as illustrated in Figure 2-5. Wintertime concentrations, by contrast, are far more uniform across the entire region. Figure 2-6 shows that on an annual basis, both total $PM_{2.5}$ and sulfate mass are highest in the southwestern portions of the MANE-VU region (note the different scales for each pollutant). High concentrations of nitrate and organic particle constituents, which play a role in localized wintertime $PM_{2.5}$ episodes, tend to be clustered along the northeastern urban corridor and in other large urban centers.

Figure 2-5. 2002 Seasonal average SO_4 based on IMPROVE and STN data

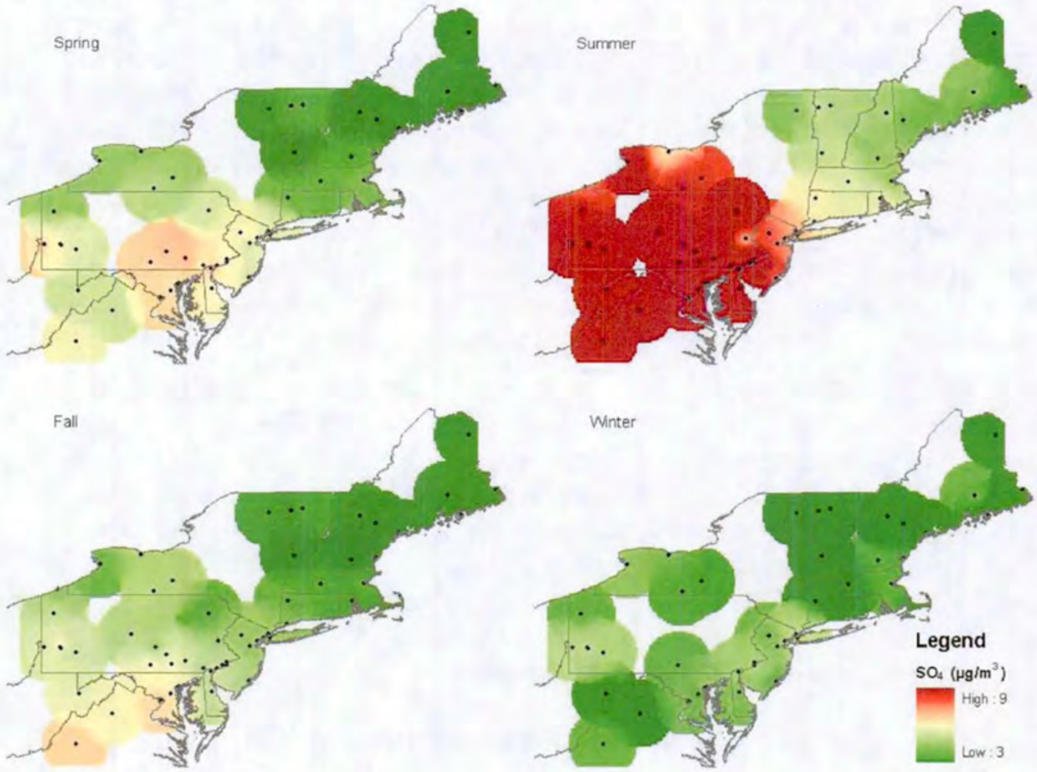
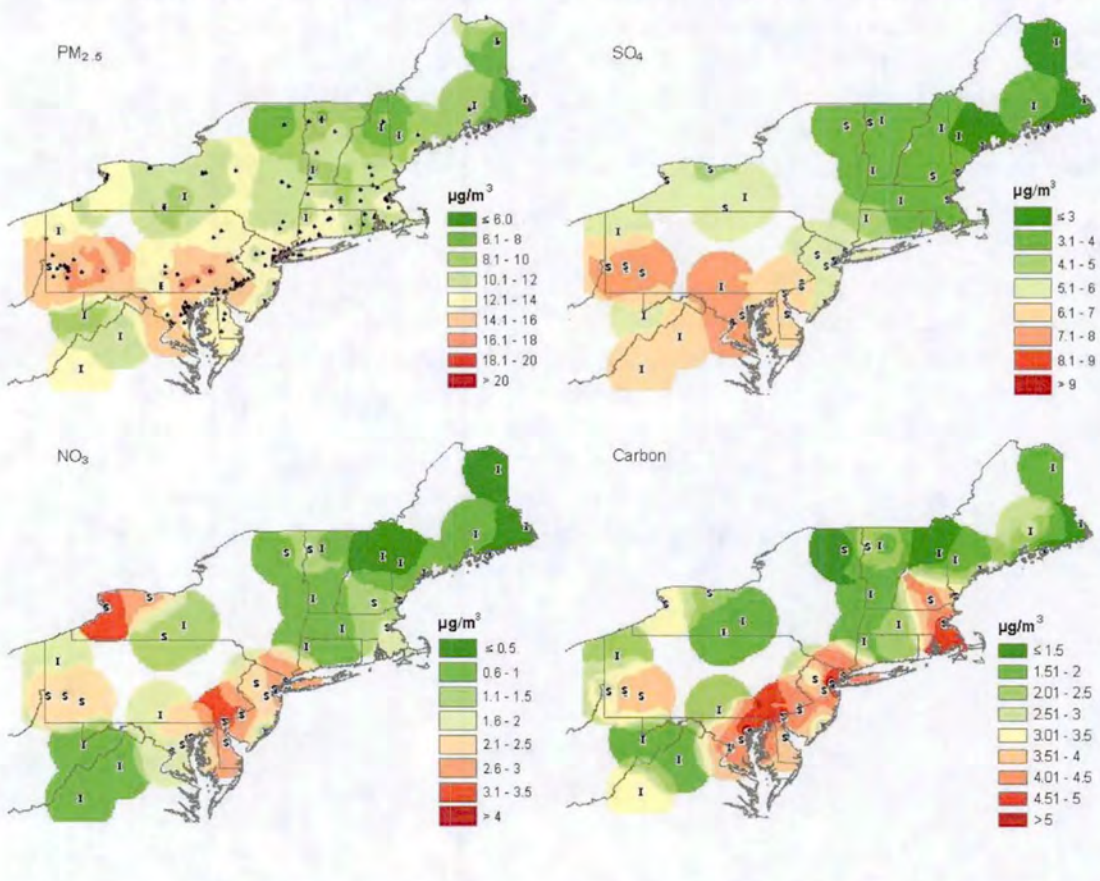


Figure 2-6. 2002 Annual average PM$_{2.5}$, sulfate, nitrate and total carbon for MANE-VU based on IMPROVE (I) and STN (S) data. PM$_{2.5}$ mass data are supplemented by measurements from the FRM network (•).



While these figures provide some preliminary context for identifying sources contributing to the region's particulate matter and visibility problems, they say nothing about the relative efficiency of a state's or region's emissions in contributing to the problem. It is clear that distance from the emissions source matters. Local, nearby sources are exceedingly important and sources within about 200 km are much more efficient (on a per ton emitted basis) at producing pollution impacts at eastern Class I sites such as Shenandoah National Park than emissions sources farther away (USNPS, 2003). In general, the "reach" of sulfate air pollution resulting from SO_2 emissions is longest (650–950 km). The reach of ammonia emissions or reduced nitrogen relative to nutrient deposition is the shortest (around 400 km), while oxides of nitrogen and sulfur — in terms of their impacts with respect to acidic deposition — have a reach between 550–650 km and 600–700 km, respectively (USNPS, 2003).

Monitoring evidence indicates that non-urban visibility impairment in eastern North America is predominantly due to sulfate particles, with organic particles generally second in importance (NARSTO, 2003). This makes sense, given the "long reach" of SO_2 emissions once they are chemically transformed into sulfate and given the ubiquitous nature of OC sources in the East. The poorest visibility conditions occur in highly industrialized areas encompassing and adjacent to the Ohio River and Tennessee Valleys. These areas feature large coal-burning power stations, steel mills, and other large emissions sources. Average fine particle concentrations and visibility conditions are also poor in the highly populated and industrialized mid-Atlantic seaboard but improve gradually northeast of New York City (Watson, 2002).

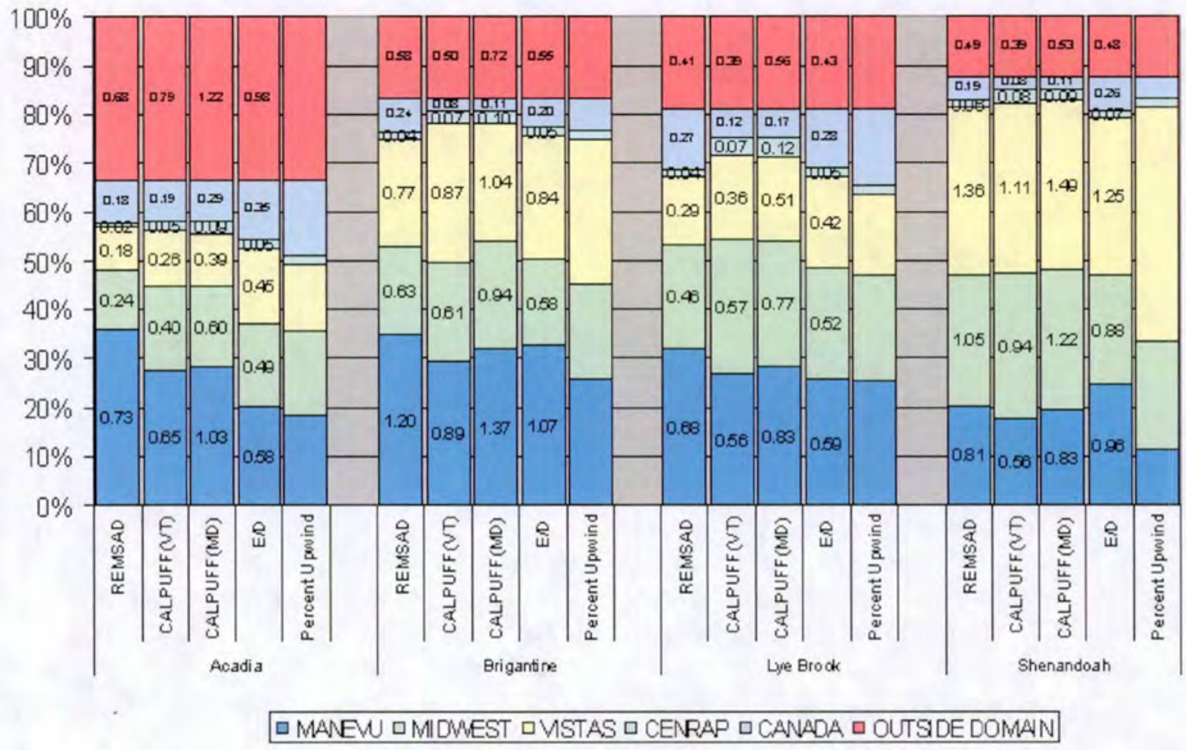
A review of source apportionment and ensemble trajectory analyses conducted by USEPA (2003) found that all back trajectory analyses for eastern sites associated sulfate with the Ohio River Valley area. These studies also are frequently able to associate other types of industrial pollutants (e.g., copper or zinc smelting, steel production, etc.) with known source areas, lending credibility to their performance. Several studies in the USEPA review noted transport across the Canadian border, specifically sulfates from the midwestern United States into Canada, and smelter emissions from Canada into the northeastern United States.

A recent, comprehensive analysis of air quality problems at Shenandoah National Park conducted by the U.S. National Park Service (USNPS, 2003) focused on contributions to particulate pollution and visibility impairment south of the MANE-VU region. In descending order of importance, the Park Service analysis determined that Ohio, Virginia, West Virginia, Pennsylvania, and Kentucky comprise the top five of 13 key states contributing to ambient sulfate concentrations and haze impacts at the park. West Virginia, Ohio, Virginia, Pennsylvania, and Kentucky comprise the top five contributing states with respect to sulfur deposition impacts at the park. Finally, Virginia, West Virginia, Ohio, Pennsylvania, and North Carolina were found to be the top five states contributing to deposition impacts from oxidized nitrogen at the park (USNPS, 2003).

In sum, the Park Service found that emission sources located within a 200 km (125 mile) radius of Shenandoah cause greater visibility and acidic deposition impacts at the park, on a per ton basis, than do more distant emissions sources (USNPS, 2003). When mapping deposition and concentration patterns for all three pollutants using contour lines, the resulting geographic pattern shows a definite eastward tilt in the area of highest impact. This is the result of prevailing wind patterns, which tend to transport most airborne pollutants in an arc[12] from the north-northeast to the east. The Park Service found, for example, that emissions originating in the Ohio River Valley end up three times farther to the east than to the west (USNPS, 2003).

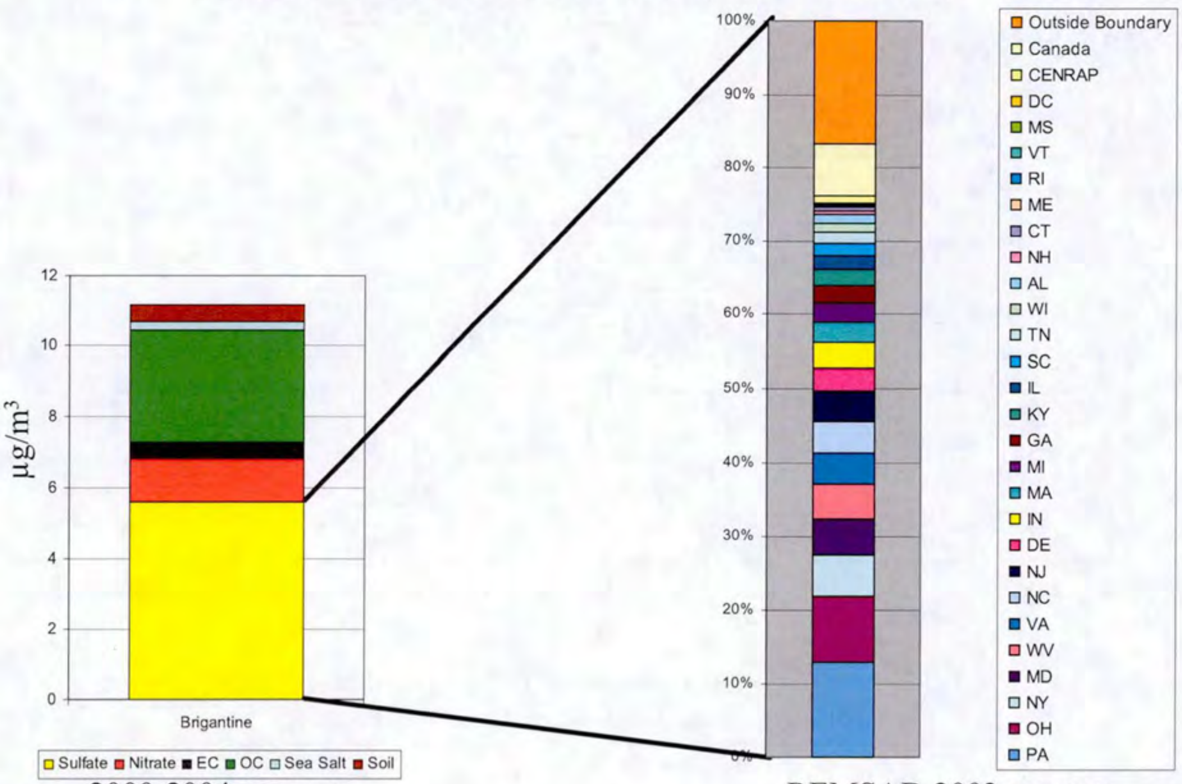
The recent sulfate attribution work completed by MANE-VU (NESCAUM, 2006) finds that a variety of different states contribute to observed sulfate in rural locations across the MANE-VU region, but that in the southwest portions of the region, neighboring RPOs contribute to a more significant degree relative to rural areas in the Northeast. Figure 2-7 shows relative contributions of RPOs to sulfate at three MANE-VU Class I areas and one VISTAS Class I area based on a variety of analysis methods. Figure 2-8 shows the individual state contributions to sulfate at Brigantine Wilderness Area on the New Jersey coast according to tagged REMSAD modeling.

Figure 2-7. 2002 Annual average contribution to $PM_{2.5}$ sulfate as determined by multiple analysis methods for four Class I areas spanning MANE-VU and Virginia



[12] The prevailing winds are eastward to northeast. This leads to greater pollution transport to the east-northeast relative to other directions.

Figure 2-8. 2002 Annual average mass contribution to $PM_{2.5}$ at Brigantine Wilderness in New Jersey (IMPROVE) and sulfate contributions as determined by tagged REMSAD model simulations (NESCAUM, 2006)



2000-2004 average IMPROVE mass

REMSAD 2002 average contributions to sulfate

2.4. CAIR Modeling

The CAIR modeling by the USEPA provides information on the upwind areas (by state) contributing to downwind nonattainment for $PM_{2.5}$ in MANE-VU counties. Table 2-1 presents the upwind states significantly contributing to $PM_{2.5}$ nonattainment in counties within MANE-VU during 2001, according to significance criteria used by the USEPA (USEPA, 2005, from Table VII-3). The states listed in the table as significantly contributing to downwind nonattainment in MANE-VU counties include states outside of MANE-VU, indicating the broad regional scale of the $PM_{2.5}$ transport problem.

Table 2-2 provides the maximum contribution from each state to annual average $PM_{2.5}$ nonattainment in a downwind state (not necessarily restricted to MANE-VU nonattainment counties) based on CAIR modeling.

Table 2-1. Upwind states that make a significant contribution to $PM_{2.5}$ in each downwind nonattainment county (2001 modeling).

Downwind State/County		Upwind States									
DE	New Castle	MD/DC	MI	NY	OH	PA	VA	WV			
DC	District of Columbia	NC	OH	PA	VA	WV					
MD	Anne Arundel	NC	OH	PA	VA	WV					
MD	Baltimore City	NC	OH	PA	VA	WV					
NJ	Union	MD/DC	MI	NY	OH	PA	WV				
NY	New York	MD/DC	OH	PA	WV						
PA	Allegheny	IL	IN	KY	MI	OH	WV				
PA	Beaver	IN	MI	OH	WV						
PA	Berks	MD/DC	MI	NY	OH	VA	WV				
PA	Cambria	IN	MD/DC	MI	OH	WV					
PA	Dauphin	MD/DC	MI	OH	VA	WV					
PA	Delaware	MD/DC	MI	OH	VA	WV					
PA	Lancaster	IN	MD/DC	MI	NY	OH	VA	WV			
PA	Philadelphia	MD/DC	MI	OH	VA	WV					
PA	Washington	IN	KY	MI	OH	WV					
PA	Westmoreland	IN	KY	MD/DC	MI	OH	WV				
PA	York	MD/DC	MI	OH	VA	WV					

Table 2-2. Maximum downwind $PM_{2.5}$ contribution ($\mu g/m^3$) for each of the 37 upwind states (2001 data).

Upwind State	Maximum Downwind Contribution	Upwind State	Maximum Downwind Contribution
Alabama	0.98	Nebraska	0.07
Arkansas	0.19	New Hampshire	<0.05
Connecticut	<0.05	New Jersey	0.13
Delaware	0.14	New York	0.34
Florida	0.45	North Carolina	0.31
Georgia	1.27	North Dakota	0.11
Illinois	1.02	Ohio	1.67
Indiana	0.91	Oklahoma	0.12
Iowa	0.28	Pennsylvania	0.89
Kansas	0.11	Rhode Island	<0.05
Kentucky	0.9	South Carolina	0.4
Louisiana	0.25	South Dakota	<0.05
Maine	<0.05	Tennessee	0.65
Maryland/DC	0.69	Texas	0.29
Massachusetts	0.07	Vermont	<0.05
Michigan	0.62	Virginia	0.44
Minnesota	0.21	West Virginia	0.84
Mississippi	0.23	Wisconsin	0.56
Missouri	1.07		

2.5. Seasonal differences

Eastern and western coastal regions of the United States and Canada show marked seasonality in the concentration and composition of fine particle pollution, while central interior regions do not (NARSTO, 2003). While MANE-VU extends inland as far as the Pennsylvania and Ohio border, the majority of $PM_{2.5}$ NAAQS nonattainment areas and Class I areas affected by the Regional Haze Rule cluster along the East Coast and thus typically show strong seasonal influences. Maximum $PM_{2.5}$ concentrations typically occur during the summer over most of the rural Northeast, with observed summer values for rural areas in the region, on average, twice those of winter. In urban locations, summertime and wintertime $PM_{2.5}$ levels are more comparable and whether one season dominates over the other is more of a function of inter-annual variability of meteorology and fire activity (i.e., summertime fire activity can push average $PM_{2.5}$ values higher in some years). As described below, the reason for the wintertime strength of $PM_{2.5}$ levels in urban areas is related to the greater concentration of local pollution that accumulates when temperature inversions are present, significantly boosting the wintertime $PM_{2.5}$ levels. Winter nitrate concentrations are generally higher than those observed in summer and, as mentioned above, urban concentrations typically exceed rural concentrations year-round. In addition, local mobile source carbon grows in importance during wintertime. Hence, in some large urban areas such as Philadelphia and New York City, peak concentrations of $PM_{2.5}$ can occur in winter.

The conceptual descriptions that explain elevated regional $PM_{2.5}$ peak concentrations in the summer differs significantly from those that explain the largely urban peaks observed during winter. On average, summertime concentrations of sulfate in the northeastern United States are more than twice that of the next most important fine particle constituent, OC, and more than four times the combined concentration of nitrate and black carbon (BC) constituents (NARSTO, 2003). Episodes of high summertime sulfate concentrations are consistent with stagnant meteorological flow conditions upwind of MANE-VU and the accumulation of airborne sulfate (via atmospheric oxidation of SO_2) followed by long-range transport of sulfur emissions from industrialized areas within and outside the region.

National assessments (NARSTO, 2003) have indicated that in the winter, sulfate levels in urban areas are almost twice as high as background sulfate levels across the eastern U.S., indicating that the local urban contribution to wintertime sulfate levels is comparable in magnitude to the regional sulfate contribution from long-range transport. MANE-VU's network analysis for the winter of 2002 suggests that the local enhancement of sulfate in urban areas of MANE-VU is somewhat less with ranges from 25 to 40% and that the long-range transport component of $PM_{2.5}$ sulfate is still the dominant contributor in most eastern cities.

In the winter, urban OC and sulfate each account for about a third of the overall $PM_{2.5}$ mass concentration observed in Philadelphia and New York City. Nitrate also makes a significant contribution to urban $PM_{2.5}$ levels observed in the northeastern United States during the winter months. Wintertime concentrations of OC and NO_3 in urban areas can be twice the average regional concentrations of these pollutants, indicating the importance of local source contributions (NARSTO, 2003). This is likely because winter conditions are more conducive to the formation of local inversion layers that prevent vertical mixing. Under these conditions, emissions from tailpipe, industrial, and other local sources become concentrated near the Earth's surface, adding to background pollution levels associated with regionally transported emissions.

It is worth noting that while sulfate plays a significant role in episodes of elevated particle pollution during summer and winter months, the processes by which sulfate forms may vary seasonally. Nearly every source apportionment study reviewed by USEPA (2003) identified secondary sulfate originating from coal combustion sources as the largest or one of the largest contributors to overall fine particle mass in the region. It often accounted for more than 50 percent of $PM_{2.5}$ mass at some locations during some seasons. In a few cases, source apportionment studies identified a known local source of sulfate, but most assessments (in conjunction with back trajectory analysis) have pointed to coal-fired power plants in the Midwest as an important source for regional sulfate. Studies with multiple years of data have also tended to identify a distinguishable chemical "signature" for winter versus summer sources of sulfate, with the summer version typically accounting for a greater share of overall fine particle mass. Researchers have speculated that the two profiles represent two extremes in the chemical transformation processes that occur in the atmosphere between the source regions where emissions are released and downwind receptor sites. We note that while coal combustion is often referred to as the "sulfate source" because of the dominance of its sulfate contribution, coal combustion is often a source of significant amounts of organic carbon and is usually the single largest source of selenium (Se) and other heavy metal trace elements (USEPA, 2003).

Figure 2-9. Moving 60-day average of fine aerosol mass concentrations based on long-term data from two northeastern cities

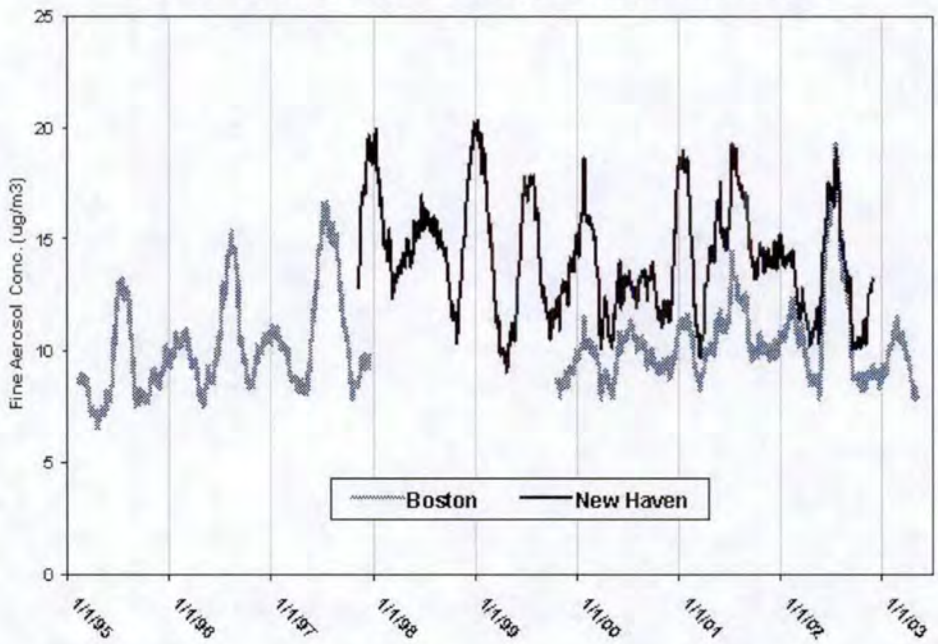
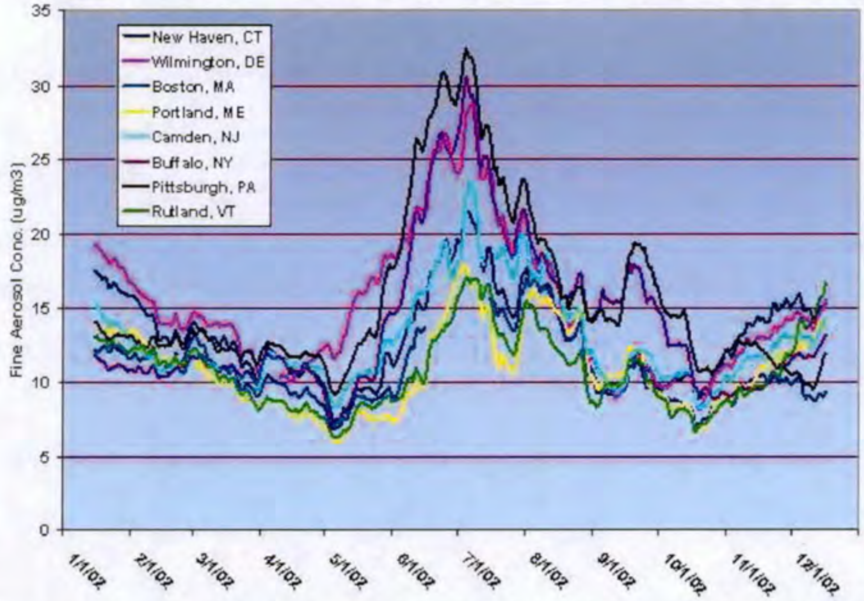


Figure 2-10. The 30-day average $PM_{2.5}$ concentrations from 8 northeastern cities during 2002



In general, fine particle concentrations in MANE-VU are highest during the warmest (summer) months but also exhibit a secondary peak during the coldest (winter) months that can dominate during some years, particularly in urban locations. This bimodal seasonal distribution of peak values is readily apparent in Figure 2-9. The figure shows the smoothed 60-day running average of fine particle mass concentrations using continuous monitoring data from two northeastern cities over a period of several years.

Figure 2-10 also demonstrates this bimodal pattern. Though slightly more difficult to discern in just a single year's worth of data, a "W" pattern does emerge at almost all sites across the region during 2002 with the winter peak somewhat lower than the summer peak at most sites. Urban monitors in Wilmington, Delaware and New Haven, Connecticut have wintertime peak values approaching those of summer.

In the summertime, MANE-VU sites repeatedly experience sulfate events due to transport from regions to the south and west. During such events, both rural and urban sites throughout MANE-VU record high (i.e., >15 $\mu g/m^3$) daily average $PM_{2.5}$ concentrations. Meteorological conditions during the summer frequently allow for summer "stagnation" events when very low wind speeds and warm temperatures (upwind and over MANE-VU) allow pollution levels to build in an air mass as it slowly moves across the continent. During these events, atmospheric ventilation is poor and local emission sources add to the burden of transported pollution with the result that concentrations throughout the region (both rural and urban) are relatively uniform. Generally, there are enough of these events to drive the difference between urban and rural sites down to less than 1 $\mu g/m^3$ during the warm or hot months of the year. As a result, concentrations of fine particles aloft will often be higher than at ground-level during the summertime, especially at rural monitoring sites. Thus, when atmospheric "mixing" occurs during summer[13] mornings (primarily 7 to 11 a.m.), fine particle concentrations at ground-level can actually increase (see Hartford, CT or Camden, NJ in Figure 2-11).

[13] Here we define summer as May, June, July and August.

Figure 2-11. Mean hourly fine aerosol concentrations during 2002 summer months

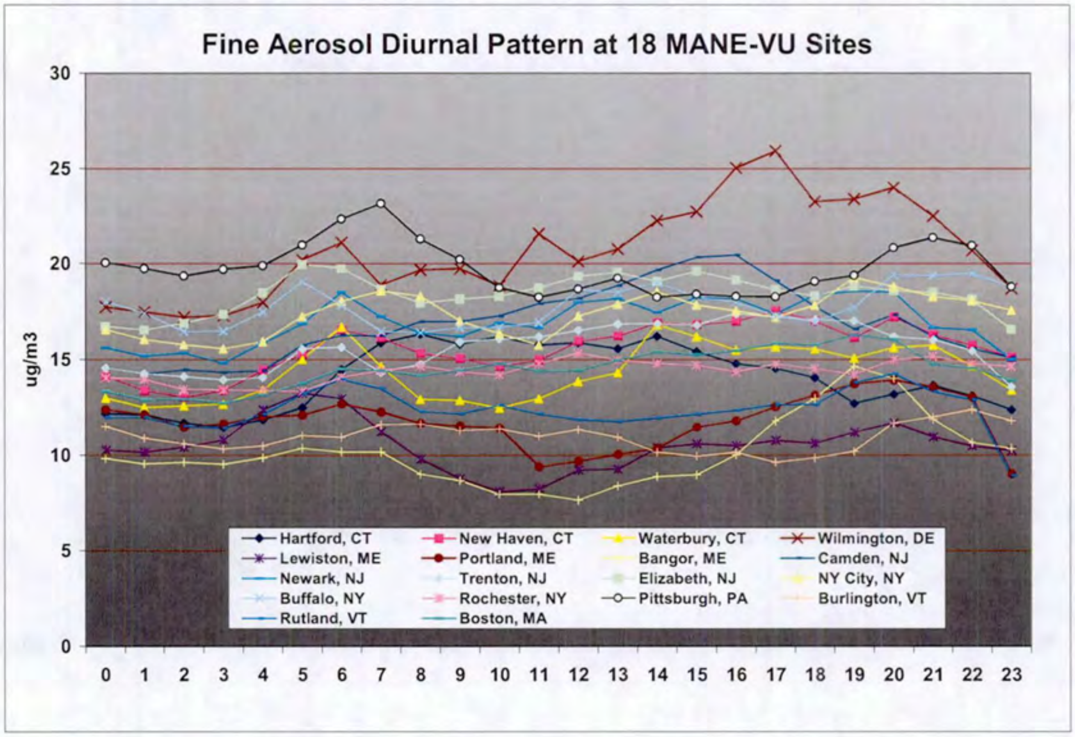
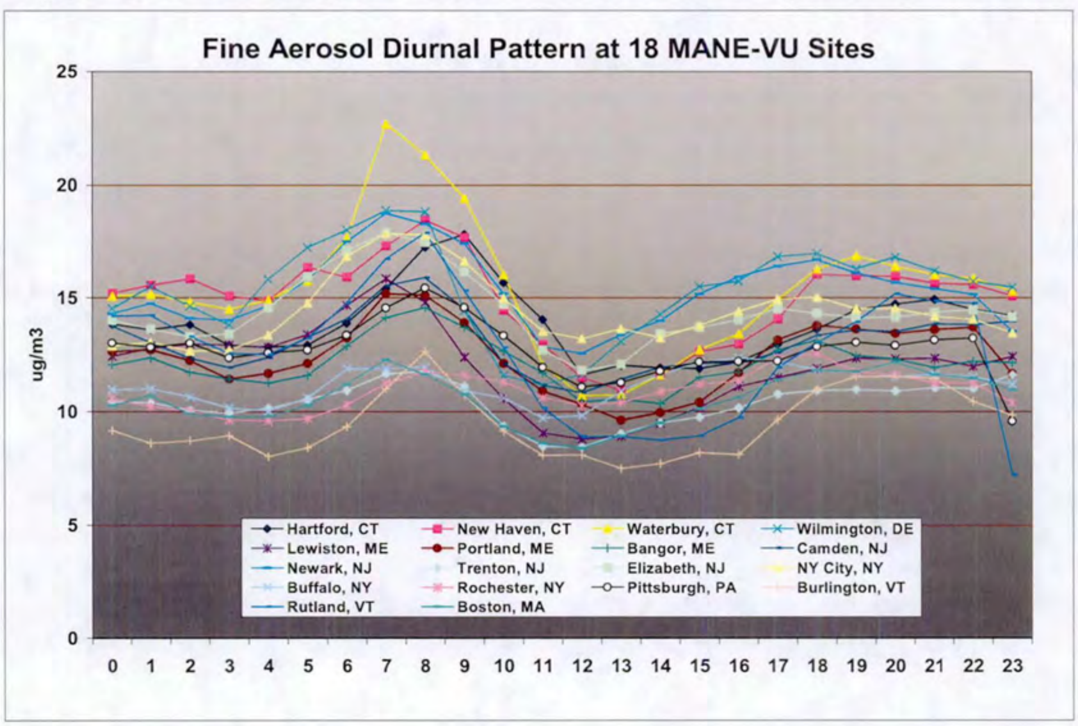


Figure 2-12. Mean hourly fine aerosol concentrations during 2002 winter months



During the wintertime, strong inversions frequently trap local emissions overnight and during the early morning, resulting in elevated urban concentrations. These inversions occur when the Earth's surface loses thermal energy by radiating it into the atmosphere (especially on clear nights). The result is a cold, stable layer of air near the ground. At sunrise, local emissions (both mobile and stationary) begin increasing in strength and build-up in the stable ground layer (which may extend only 100 meters or less above the ground). Increasing solar radiation during the period between 10 a.m. and noon typically breaks this cycle by warming the ground layer so that it can rise and mix with air aloft. Because the air aloft during wintertime is typically less polluted than the surface layer, this mixing tends to reduce ground-level particle concentrations (see Figure 2-12). This diurnal cycle generally drives wintertime particle concentrations, although the occasional persistent temperature inversion can have the effect of trapping and concentrating local emissions over a period of several days, thereby producing a significant wintertime pollution episode.

Rural areas experience the same temperature inversions but have relatively fewer local emissions sources so that wintertime concentrations in rural locations tend to be lower than those in nearby urban areas. Medium and long-range fine particle transport events do occur during the winter but to a far lesser extent than in the summertime. In sum, it is the interplay between local and distant sources together with seasonal meteorological conditions that drives the observed 3–4 $\mu g/m^3$ wintertime urban-rural difference in $PM_{2.5}$ concentrations.

Visually hazy summer days in the Northeast can appear quite different from hazy winter days. The milky, uniform visibility impairment shown in Figure 2-13 is typical of summertime regional haze events in the Northeast. During the winter, by comparison, reduced convection and the frequent occurrence of shallow inversion layers often creates a layered haze with a brownish tinge, as shown in Figure 2-14. This visual difference suggests seasonal variation in the relative contribution of different gaseous and particle constituents during the summer versus winter months (NESCAUM, 2001). Rural and inland areas tend not to experience these layered haze episodes as frequently due to the lack of local emission sources in most rural areas (valleys with high wood smoke contributions are an exception).

Overall (regional) differences in summer versus winter particle mass concentrations and corresponding visibility impairment (as measured by light extinction) are largely driven by seasonal variation in sulfate mass concentrations. This is because winter meteorological conditions are less conducive to the oxidation of sulfate from SO_2 (as borne out by the previously cited source apportionment studies). In addition, seasonal differences in long-range transport patterns from upwind SO_2 source regions may be a factor.

The greater presence of nitrate during the cold season is a consequence of the chemical properties of ammonium nitrate. Ammonia bonds more weakly to nitrate than it does to sulfate, and ammonium nitrate tends to dissociate at higher temperatures. Consequently, ammonium nitrate becomes more stable at lower temperatures and hence contributes more to $PM_{2.5}$ mass and light extinction during the winter months relative to the summer (NESCAUM, 2001).

Figure 2-13. Summertime at Mt. Washington

Clean Day

Typical Haze Event

Figure 2-14. Wintertime in Boston

Clean Day

Typical Haze Event

2.6. Summary

The presence of fine particulate matter in ambient air significantly degrades public health and obscures visibility during most parts of the year at sites across the MANE-VU region. Particle pollution generally, and its sulfate component specifically, constitute the principle driver for regional visibility impacts. While the broad region experiences visibility impairment, it is most severe in the southern and western portions of MANE-VU that are closest to large power plant SO_2 sources in the Ohio River and Tennessee Valleys.

Summer visibility impairment is driven by the presence of regional sulfate, whereas winter visibility depends on a combination of regional and local influences coupled with local meteorological conditions (inversions) that lead to the concentrated build-up of pollution.

Sulfate is the key particle constituent from the standpoint of designing control strategies to improve visibility conditions in the northeastern United States. Significant further reductions in ambient sulfate levels are achievable, though they will require more than proportional reductions in SO_2 emissions.

Long-range pollutant transport and local pollutant emissions are important, especially along the eastern seaboard, so one must also look beyond the achievement of further sulfate reductions. During the winter months, in particular, consideration also needs to be given to reducing urban sources of SO_2, NO_X and OC (NARSTO, 2003) .

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3. MANE-VU EMISSION INVENTORY CHARACTERISTICS FOR FINE PARTICLES

The pollutants that affect fine particle formation and visibility are sulfur oxides (SO_X), NO_X, VOCs, ammonia (NH_3), and particles with an aerodynamic diameter less than or equal to 10 and 2.5 μm (i.e., primary PM_{10} and $PM_{2.5}$). The emissions dataset illustrated in this section is the 2002 MANE-VU Version 2 regional haze emissions inventory. The MANE-VU regional haze emissions inventory version 3.0, released in April 2006, has superseded version 2 for modeling purposes.

3.1. Emissions inventory characteristics

3.1.1. Sulfur dioxide (SO_2)

SO_2 is the primary precursor pollutant for sulfate particles. Ammonium sulfate particles are the largest contributor to $PM_{2.5}$ mass on an annual average basis at MANE-VU nonattainment sites. It also accounts for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as or more than 80 percent on the haziest days. Hence, SO_2 emissions are an obvious target of opportunity for both addressing $PM_{2.5}$ nonattainment and for reducing regional haze in the eastern United States. Combustion of coal and, to a substantially lesser extent, of certain petroleum products accounts for most anthropogenic SO_2 emissions. In fact, in 1998 a single source category — coal-burning power plants — was responsible for two-thirds of total SO_2 emissions nationwide (NESCAUM, 2001).

Figure 3-1 shows SO_2 emissions trends in MANE-VU states[14] extracted from the National Emissions Inventories (NEI) for the years 1996, 1999 (MARAMA, 2004), and the 2002 MANE-VU inventory. Most of the states (with the exception of Maryland) show declines in year 2002 annual SO_2 emissions as compared to 1996 emissions. Some of the states show an increase in 1999 followed by a decline in 2002 and others show consistent declines throughout the entire period. The upward trend in emissions after 1996 probably reflects electricity demand growth during the late 1990s combined with the availability of banked SO_2 emissions allowances from initial over-compliance with control requirements in Phase 1 of the USEPA Acid Rain Program. This led to relatively low market prices for allowances later in the decade, which encouraged utilities to purchase allowances rather than implement new controls as electricity output expanded. The observed decline in the 2002 SO_2 emissions inventory reflects implementation of the second phase of the USEPA Acid Rain Program, which in 2000 further reduced allowable emissions and extended emissions limits to more power plants.

Figure 3-2 shows the percent contribution from different source categories to overall annual 2002 SO_2 emissions in MANE-VU states. The chart shows that point sources dominate SO_2 emissions, which primarily consist of stationary combustion sources for generating electricity, industrial energy, and heat. Smaller stationary combustion sources called "area sources" (primarily commercial and residential heating)

[14] The description of MANE-VU state inventories discussed throughout this section does not include the portion of Virginia in the Washington, DC metropolitan area.

are another important source category in MANE-VU states. By contrast, on-road and non-road mobile sources make only a relatively small contribution to overall SO_2 emissions in the region (NESCAUM, 2001).

Figure 3-1. State level sulfur dioxide emissions

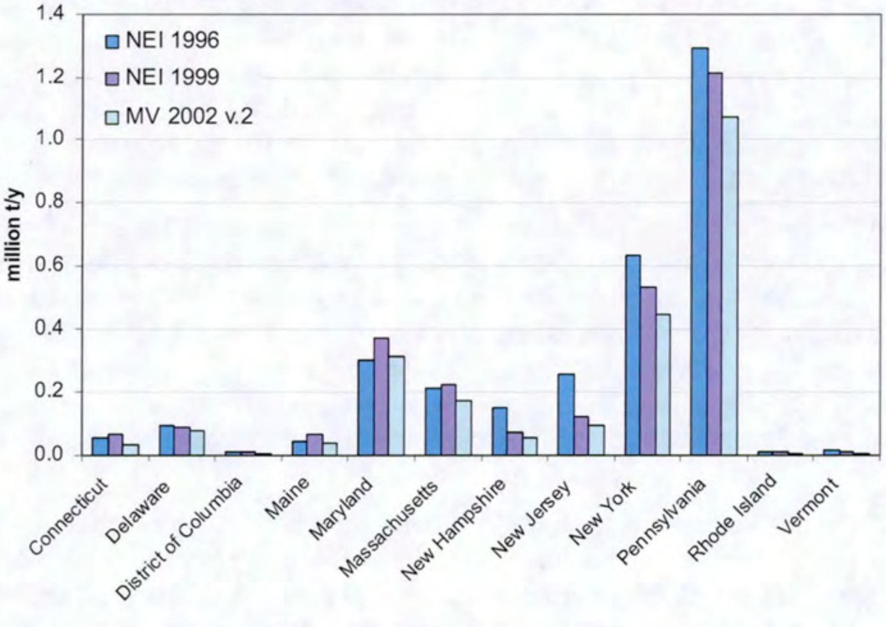


Figure 3-2. 2002 MANE-VU state SO_2 inventories

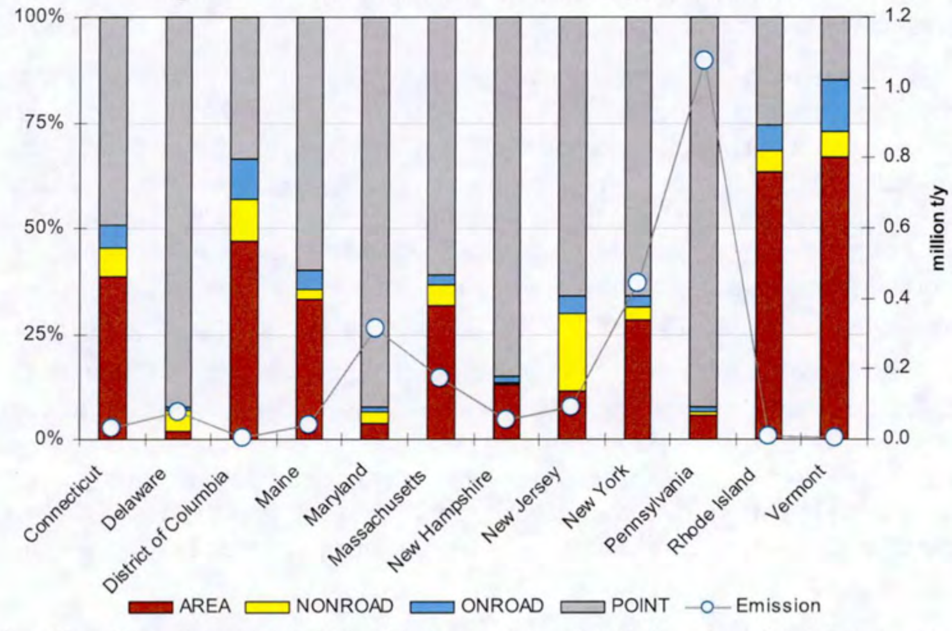


Figure Key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.2. Volatile organic compounds (VOCs)

Existing emission inventories generally refer to VOCs based on their historical contribution to ozone formation. From a fine particle perspective, VOCs (also referred to as hydrocarbons) are of concern because they can react in the atmosphere to form secondary organic aerosol (SOA) as a result of condensation and oxidation processes. The SOA component of fine particles also obscures visibility, but this component has a smaller impact on visibility (on a per unit mass basis) relative to sulfate or nitrate, which have an affinity for water that allows them to significantly "grow" as particles under humid conditions. Nonetheless, organic carbon typically has the second largest visibility impact at most Class I sites next to sulfate, given its large mass contribution.

As shown in Figure 3-3, the VOC inventory is dominated by mobile and area sources. Most VOC emissions in MANE-VU, however, come from natural sources, which are not shown in the figure. Among the human-caused VOC emissions, on-road mobile sources of VOCs include exhaust emissions from gasoline passenger vehicles and diesel-powered heavy-duty vehicles as well as evaporative emissions from transportation fuels. VOC emissions may also originate from a variety of area sources (including solvents, architectural coatings, and dry cleaners) as well as from some point sources (e.g., industrial facilities and petroleum refineries).

Naturally occurring (biogenic) VOC emissions are caused by the release of natural organic compounds from plants in warm weather. Natural, or biogenic, VOCs contribute significantly to fine particle formation. Biogenic VOCs are not included in Figure 3-3, but nationally, they represent roughly two-thirds of all annual VOC emissions (USEPA, 2006). Biogenic emissions are extremely difficult to estimate, as it requires modeling the behavior of many plants as well as their responses to the environment.

With regard to fine particle formation, understanding the transport dynamics and source regions for organic carbon is likely to be more complex than for sulfate. This is partly because of the large number and variety of VOC species, the fact that their transport characteristics vary widely, and the fact that a given species may undergo numerous complex chemical reactions in the atmosphere. Thus, the organic carbon contribution to fine particles in the East is likely to include manmade pollution transported from a distance, manmade pollution from nearby sources, and biogenic emissions, especially terpenes from coniferous forests.

For fine particles derived from organic carbon, the oxidation of hydrocarbon molecules containing seven or more carbon atoms is generally the most significant pathway for their formation (Odum *et al.*, 1997). Recent research, however, suggests that smaller reactive hydrocarbons like isoprene not only contribute significantly to ground-level ozone, which may indirectly impact organic aerosol formation, but also contribute directly to ambient organic aerosol through heterogeneous processes (Claeys et al., 2004; Kroll et al., 2005).

Figure 3-3. 2002 MANE-VU state VOC inventories

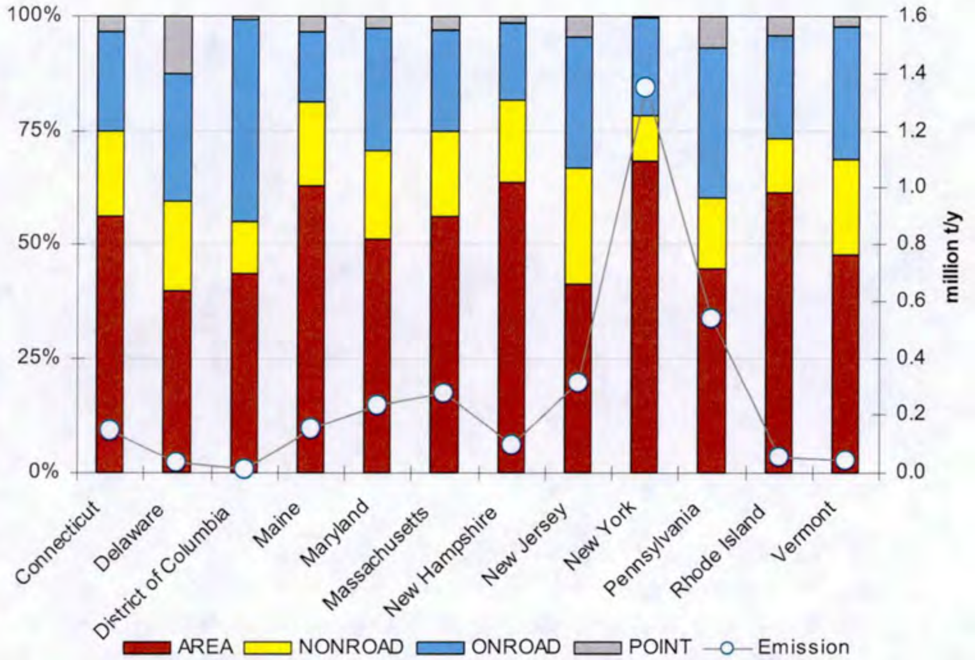


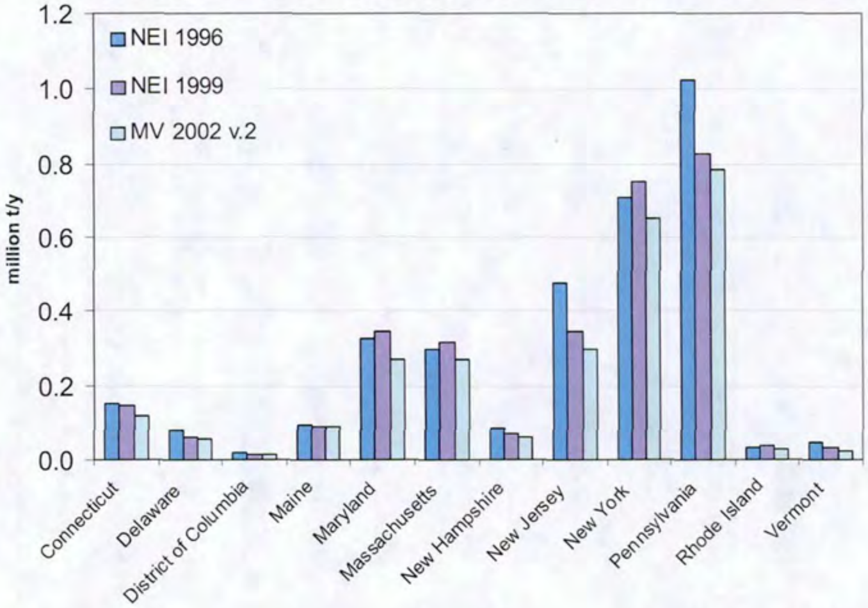
Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure. Biogenic VOCs are not included in this figure.

3.1.3. Oxides of nitrogen (NO_X)

NO_X emissions contribute directly to $PM_{2.5}$ nonattainment and visibility impairment in the eastern U.S. by forming nitrate particles. Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon regionally in MANE-VU. Notably, nitrate may play a more important role at urban sites and in the wintertime. In addition, NO_X may have an indirect effect on summertime visibility by virtue of its role in the formation of ozone, which in turn promotes the formation of secondary organic aerosols (NESCAUM, 2001).

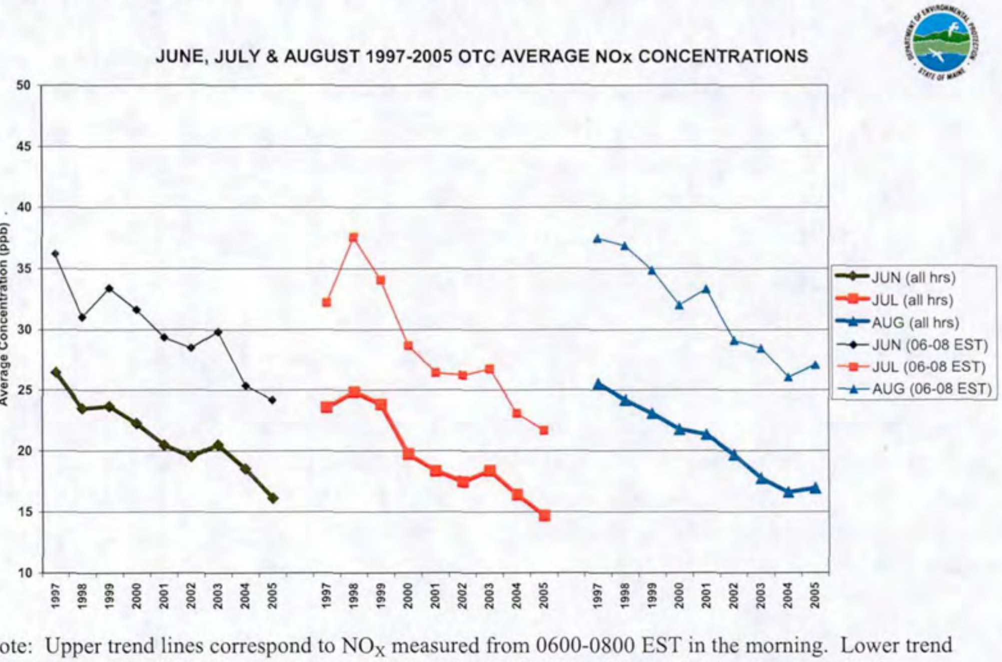
Figure 3-4 shows NO_X emissions in MANE-VU at the state level. Since 1980, nationwide emissions of NO_X from all sources have shown little change. In fact, emissions increased by 2 percent between 1989 and 1998 (USEPA, 2000a). This increase is most likely due to industrial sources and the transportation sector, as power plant combustion sources have implemented modest emissions reductions during the same time period. Most states in MANE-VU experienced declining NO_X emissions from 1996 through 2002, except Massachusetts, Maryland, New York, and Rhode Island, which show an increase in NO_X emissions in 1999 before declining to levels below 1996 emissions in 2002.

Figure 3-4. State level nitrogen oxides emissions



Monitored ambient NO_X trends during the summer from 1997 to 2005 corroborate the downward trend in NO_X emissions seen in the emissions inventories for MANE-VU. As seen in Figure 3-5, the 24-hour (lower trend lines) and 6 a.m.-8 a.m. (upper trend lines) NO_X concentrations indicate decreases in NO_X over this time period in MANE-VU. The NO_X reductions likely come from decreasing vehicle NO_X emissions due to more stringent motor vehicle standards as well as NO_X reductions from MANE-VU NO_X Budget Program and the NO_X SIP Call (mainly power plants).

Figure 3-5. Plot of monitored NO_X trends in MANE-VU during 1997-2005



Note: Upper trend lines correspond to NO_X measured from 0600-0800 EST in the morning. Lower trend lines correspond to NO_X measured over entire day (created by Tom Downs, Maine Department of Environmental Protection).

Power plants and mobile sources generally dominate state and national NO_X emissions inventories. Nationally, power plants account for more than one-quarter of all NO_X emissions, amounting to over six million tons. The electric sector plays an even larger role, however, in parts of the industrial Midwest where high NO_X emissions have a particularly significant power plant contribution. By contrast, mobile sources dominate the NO_X inventories for more urbanized mid-Atlantic and New England states to a far greater extent, as shown in Figure 3-6. In these states, on-road mobile sources — a category that mainly includes highway vehicles — represent the most significant NO_X source category. Emissions from non-road (i.e., off-highway) mobile sources, primarily diesel-fired engines, also represent a substantial fraction of the inventory.

Figure 3-6. 2002 MANE-VU state NO_X inventories

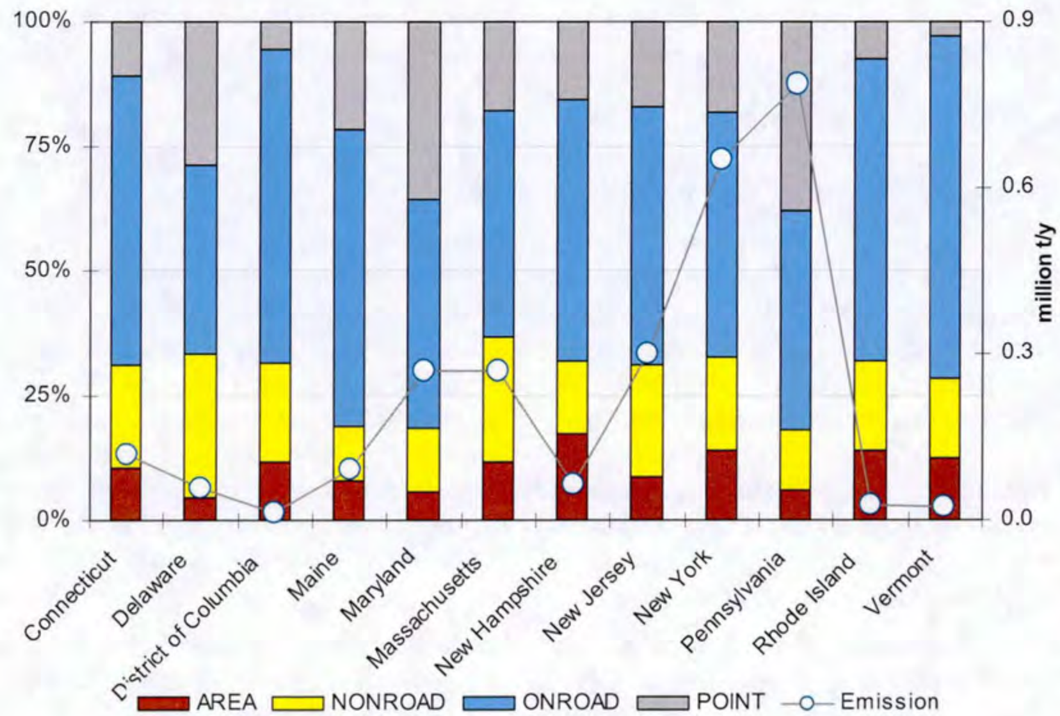


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.4. Primary particulate matter (PM_{10} and $PM_{2.5}$)

Directly-emitted or "primary" particles (as distinct from secondary particles that form in the atmosphere through chemical reactions involving precursor pollutants like SO_2 and NO_X) also contribute to fine particle levels in the atmosphere. For regulatory purposes, we make a distinction between particles with an aerodynamic diameter less than or equal to 10 micrometers and smaller particles with an aerodynamic diameter less than or equal to 2.5 micrometers (i.e., primary PM_{10} and $PM_{2.5}$, respectively).

Figure 3-7 and Figure 3-8 show PM_{10} and $PM_{2.5}$ emissions for MANE-VU states for the years 1996, 1999, and 2002. Note that, as opposed to the other constituents of PM, the 2002 inventory values for PM_{10} are drawn from the 2002 NEI. Most states show a steady decline in annual PM_{10} emissions over this time period. By contrast, emission trends for primary $PM_{2.5}$ are more variable.

Crustal sources are significant contributors of primary PM emissions. This category includes fugitive dust emissions from construction activities, paved and unpaved roads, and agricultural tilling. Typically, monitors estimate PM_{10} emissions from these types of sources by measuring the horizontal flux of particulate mass at a fixed downwind sampling location within perhaps 10 meters of a road or field. Comparisons between estimated emission rates for fine particles using these types of measurement techniques and observed concentrations of crustal matter in the ambient air at downwind receptor sites suggest that physical or chemical processes remove a significant fraction of crustal material relatively quickly. As a result, it rarely entrains into layers of the atmosphere where it can transport to downwind receptor locations. Because of this discrepancy between estimated emissions and observed ambient concentrations, modelers typically reduce estimates of total $PM_{2.5}$ emissions from all crustal sources by applying a factor of 0.15 to 0.25 before including in modeling analyses.

From a regional haze perspective, crustal material generally does not play a major role. On the 20 percent best-visibility days during the baseline period (2000-2004), it accounted for 6 to 11 percent of particle-related light extinction at MANE-VU Class 1 sites. On the 20 percent worst-visibility days, however, crustal material generally plays a much smaller role relative to other haze-forming pollutants, ranging from 2 to 3 percent. Moreover, the crustal fraction includes material of natural origin (such as soil or sea salt) that is not targeted under USEPA's Regional Haze Rule. Of course, the crustal fraction can be influenced by certain human activities, such as construction, agricultural practices, and road maintenance (including wintertime salting) — thus, to the extent that these types of activities are found to affect visibility at northeastern Class I sites, control measures targeted at crustal material may prove beneficial.

Experience from the western United States, where the crustal component has generally played a more significant role in driving overall particulate levels, may be helpful where it is relevant in the eastern context. In addition, a few areas in the Northeast, such as New Haven, Connecticut and Presque Isle, Maine, have some experience with the control of dust and road-salt as a result of regulatory obligations stemming from their past nonattainment status with respect to the NAAQS for PM_{10}.

Current emissions inventories for the entire MANE-VU area indicate residential wood combustion represents 25 percent of primary fine particulate emissions in the region. This implies that rural sources can play an important role in addition to the contribution from the region's many highly populated urban areas. An important consideration in this regard is that residential wood combustion occurs primarily in the winter months, while managed or prescribed burning activities occur largely in other seasons. The latter category includes agricultural field-burning activities, prescribed burning of forested areas, and other burning activities such as construction waste burning. Limiting burning to times when favorable meteorological conditions can efficiently disperse resulting emissions can manage many of these types of sources.

Figure 3-7. State level primary PM_{10} emissions

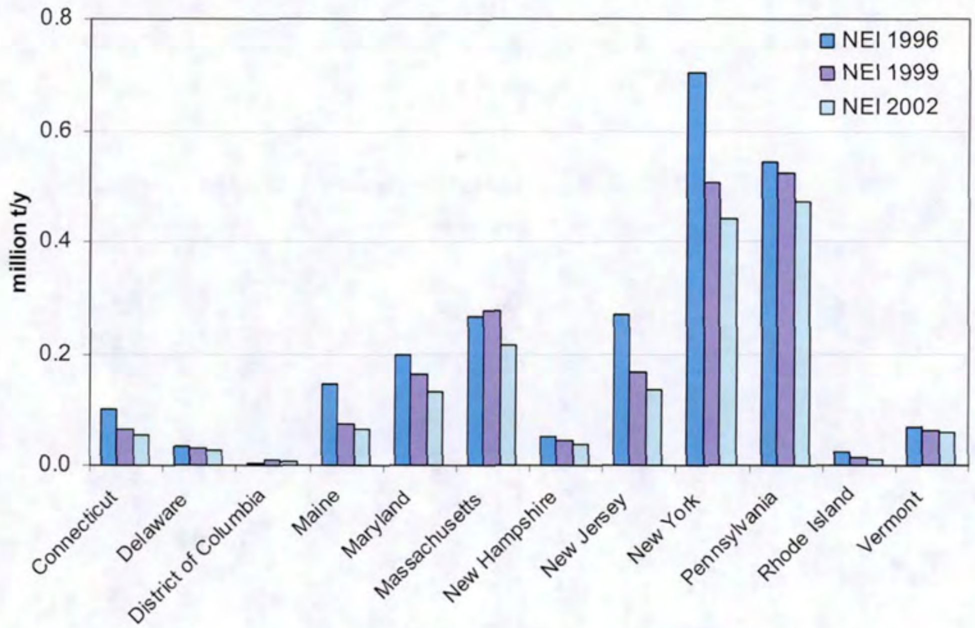


Figure 3-8. State level primary $PM_{2.5}$ emissions

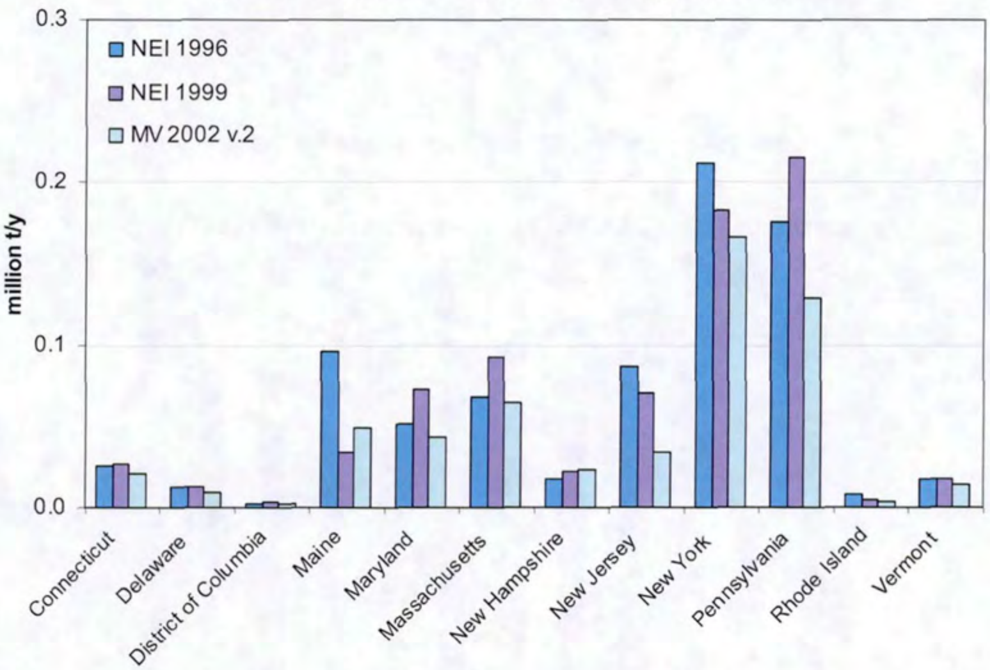


Figure 3-9 and Figure 3-10 show that area and mobile sources dominate primary PM emissions. (The NEI inventory categorizes residential wood combustion and some other combustion sources as area sources.) The relative contribution of point sources is larger in the primary $PM_{2.5}$ inventory than in the primary PM_{10} inventory since the crustal component (which consists mainly of larger or "coarse-mode" particles) contributes mostly to overall PM_{10} levels. At the same time, pollution control equipment commonly installed at large point sources is usually more efficient at capturing coarse-mode particles.

Figure 3-9. 2002 MANE-VU state primary PM_{10} inventories

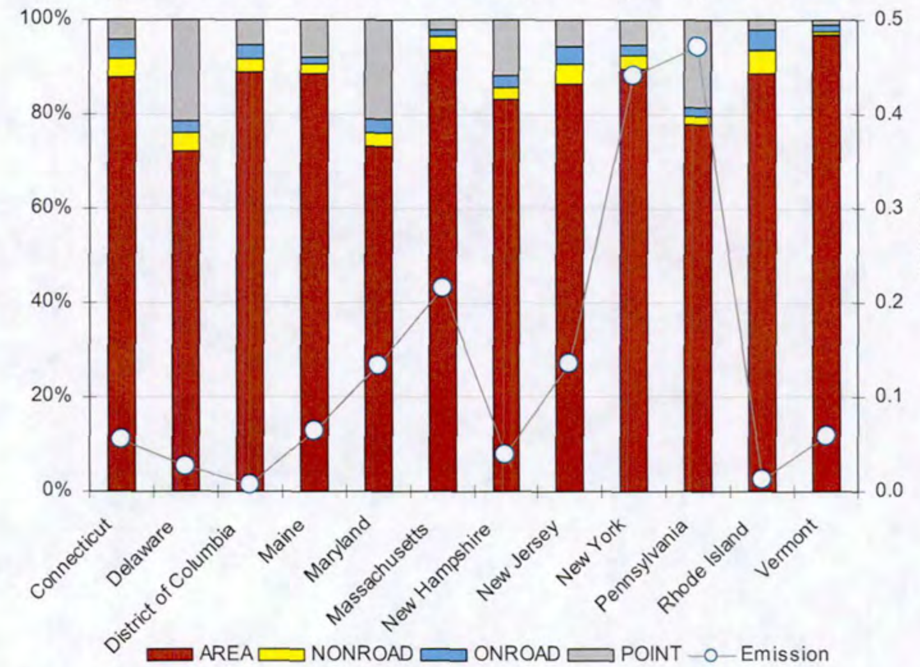


Figure 3-10. 2002 MANE-VU state primary $PM_{2.5}$ inventories

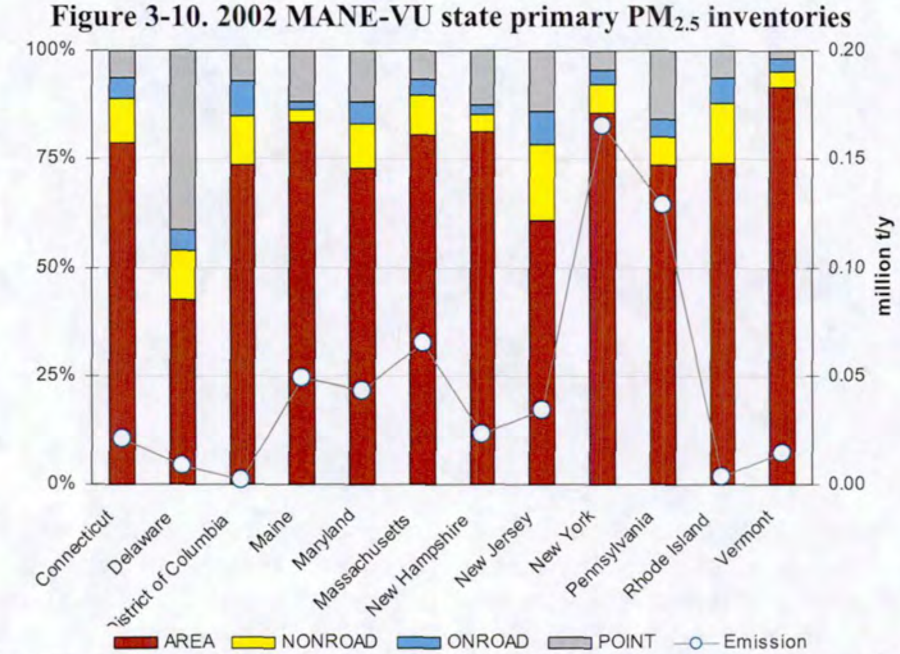


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.5. Ammonia emissions (NH_3)

Knowledge of ammonia emission sources will be necessary in developing effective regional haze reduction strategies because of the importance of ammonium sulfate and ammonium nitrate in determining overall fine particle mass and light scattering. According to 1998 estimates, livestock and agriculture fertilizer use accounted for approximately 85 percent of all ammonia emissions to the atmosphere (USEPA, 2000b). We need, however, better ammonia inventory data for the photochemical models used to simulate fine particle formation and transport in the eastern United States. Because the USEPA does not regulate ammonia as a criteria pollutant or as a criteria pollutant precursor, these data do not presently exist at the same level of detail or certainty as for NO_X and SO_2.

Ammonium ion (formed from ammonia emissions to the atmosphere) is an important constituent of airborne particulate matter, typically accounting for 10–20 percent of total fine particle mass. Reductions in ammonium ion concentrations can be extremely beneficial because a more-than-proportional reduction in fine particle mass can result. Ansari and Pandis (1998) showed that a one $\mu g/m^3$ reduction in ammonium ion could result in up to a four $\mu g/m^3$ reduction in fine particulate matter. Decision makers, however, must weigh the benefits of ammonia reduction against the significant role it plays in neutralizing acidic aerosol. SO_2 reacts in the atmosphere to form sulfuric acid (H_2SO_4). Ammonia can partially or fully neutralize this strong acid to form ammonium bisulfate or ammonium sulfate. If planners focus future control strategies on ammonia and do not achieve corresponding SO_2 reductions, fine particles formed in the atmosphere will be substantially more acidic than those presently observed.

To address the need for improved ammonia inventories, MARAMA, NESCAUM and USEPA funded researchers at Carnegie Mellon University (CMU) in Pittsburgh to develop a regional ammonia inventory system (Davidson et al., 1999). This study focused on three issues with respect to current emissions estimates: (1) a wide range of ammonia emission factor values, (2) inadequate temporal and spatial resolution of ammonia emissions estimates, and (3) a lack of standardized ammonia source categories.

Figure 3-11 shows that estimated ammonia emissions were fairly stable in the 1996, 1999, and 2002 NEI for MANE-VU states, with some increases observed for Massachusetts, New Jersey and New York. Area and on-road mobile sources dominate the ammonia inventory, according to Figure 3-12. Specifically, emissions from agricultural sources and livestock production account for the largest share of estimated ammonia emissions in MANE-VU, except in the District of Columbia. The two remaining sources with a significant emissions contribution are wastewater treatment systems and gasoline exhaust from highway vehicles.

Figure 3-11. State level ammonia emissions

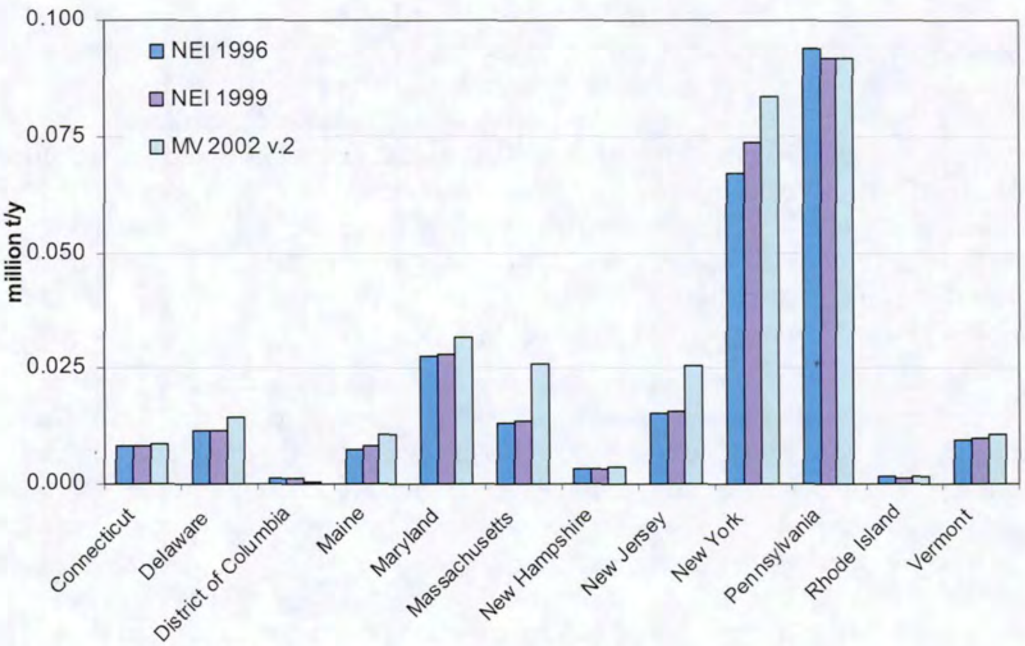


Figure 3-12. 2002 MANE-VU state NH_3 inventories

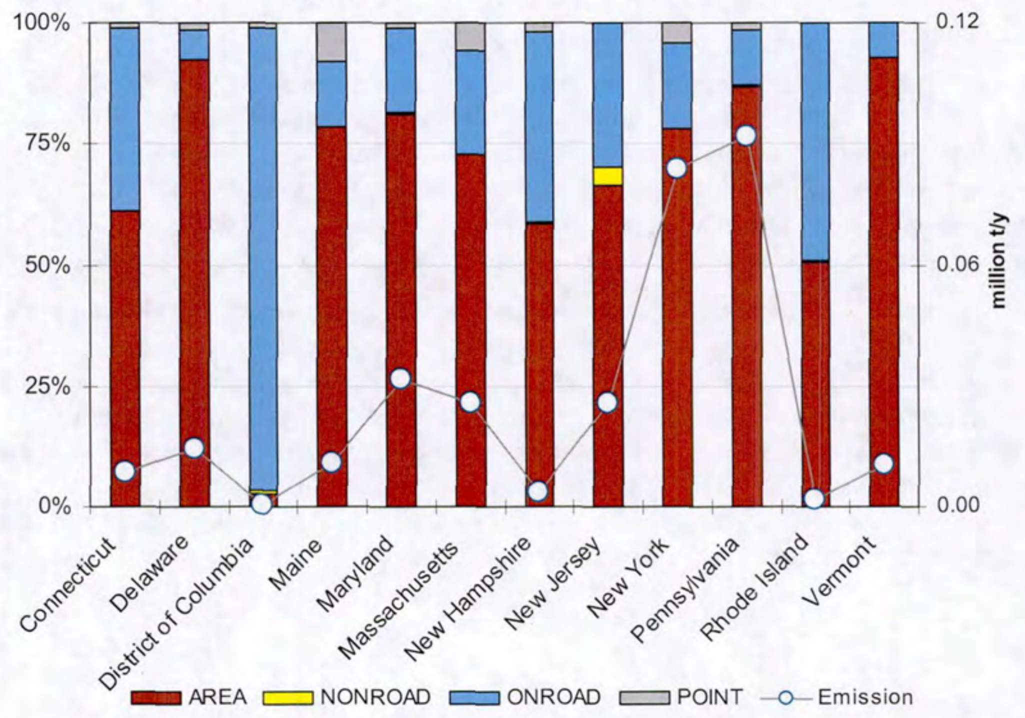


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.2. Emissions inventory characteristics outside MANE-VU

SO_2, NO_X and VOC emissions from within MANE-VU are only one component of the emissions contributing to fine particles affecting the MANE-VU region. As regional modeling for the CAIR has shown, emission sources, primarily of SO_2 and NO_X, located outside MANE-VU can significantly contribute to particle sulfate and nitrate transported into the MANE-VU region. Here we present regional emissions information grouped by the three eastern RPOs – MANE-VU, VISTAS (Visibility Improvement State and Tribal Association of the Southeast), and the MWRPO (Midwest RPO). Table 3-1 lists the states in each RPO.

The inventory information is extracted from the USEPA final 2002 National Emissions Inventory (NEI). For consistency, the MANE-VU information here also comes from the 2002 NEI rather than from the MANE-VU Version 2 regional haze emissions inventory described in Section 3.1. The differences between the inventories are not great, as the NEI and the MANE-VU Version 2 inventory are both based on the same inventory information provided by the states.

Table 3-1. Eastern U.S. RPOs and their state members

RPO	State
MWRPO	Illinois
MWRPO	Indiana
MWRPO	Michigan
MWRPO	Ohio
MWRPO	Wisconsin
MANE-VU	Connecticut
MANE-VU	Delaware
MANE-VU	District of Columbia
MANE-VU	Maine
MANE-VU	Maryland
MANE-VU	Massachusetts
MANE-VU	New Hampshire
MANE-VU	New Jersey
MANE-VU	New York
MANE-VU	Pennsylvania
MANE-VU	Rhode Island
MANE-VU	Vermont
VISTAS	Alabama
VISTAS	Florida
VISTAS	Georgia
VISTAS	Kentucky
VISTAS	Mississippi
VISTAS	North Carolina
VISTAS	South Carolina
VISTAS	Tennessee
VISTAS	Virginia
VISTAS	West Virginia

Table 3-2 presents SO_2 emissions by source sector and RPO for the eastern United States. The NO_X emissions by source sector and RPO are presented in Table 3-3 and VOC emissions in Table 3-4. Regionally, SO_2 emissions are more important with respect to regional particle formation and transport. NO_X emissions play an important role in determining the equilibrium between ammonium sulfate and ammonium nitrate formation, especially during winter. VOC emissions contribute to secondary organic aerosol formation.

Table 3-2. SO_2 emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	3,336,967	133,415	49,191	82,307	3,601,880
MANE-VU	1,924,573	353,176	39,368	74,566	2,391,683
VISTAS	4,349,437	448,023	83,001	91,307	4,971,769

Table 3-3. NO_X emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	1,437,284	184,790	1,290,178	723,844	3,636,096
MANE-VU	680,975	268,997	1,297,357	534,454	2,781,783
VISTAS	2,094,228	266,848	2,160,601	812,615	5,334,293

Table 3-4. VOC emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	234,938	1,182,186	660,010	492,027	2,569,160
MANE-VU	93,691	1,798,158	793,541	494,115	3,179,504
VISTAS	458,740	2,047,359	1,314,979	609,539	4,430,617

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Davidson, C., R. Strader, S. Pandis, and A. Robinson. *Preliminary Proposal to MARAMA and NESCAUM: Development of an Ammonia Emissions Inventory for the Mid-Atlantic States and New England.* Carnegie Mellon University, Pittsburgh, PA, January 7, 1999.

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USEPA. *2002 Final National Emissions Inventory (NEI)*, available online: ftp://ftp.epa.gov/EmisInventory/2002finalnei/, 2006 (accessed October 10, 2006) [The 2002 NEI reports national annual emissions for total anthropogenic VOC emissions as 16.8 million tons, and total biogenic VOC emissions as 41.8 million tons].

4. WHAT WILL IT TAKE TO CLEAN THE AIR?

In this chapter we build on the conceptual description of fine particle formation and impacts in the MANE-VU region by looking at a typical fine particle pollution event and the meteorological and chemical conditions which contributed to its formation. As an illustration of how the conceptual elements laid out in Chapter 2 and 3 contribute to a pollution event under real-world circumstances, we examine a pollution event from 2002. We examine this event from two perspectives: (1) the broad spatial patterns of the formation and transport of particle air pollution and (2) the chronological sequence of events at a few discrete points where high temporal resolution monitoring was in place. We then proceed to examine likely emission reduction strategies that should be considered in light of the conceptual understanding of fine particle formation and transport developed in this report.

4.1. Meteorological and Pollution Overview of August 8-16, 2002

Annual and seasonal statistics are useful for understanding the general patterns of air pollution in our region, but it is also instructive to review specific high $PM_{2.5}$ episodes in order to shed more light on the meteorological circumstances under which high ambient concentrations of $PM_{2.5}$ are able to form from emitted precursor pollutants. Here we present an analysis of the high $PM_{2.5}$ and regional haze episode of August 2002 by reviewing surface maps from the period to provide a synoptic overview of major weather systems that were influencing air quality across the Northeast U.S. during that time.

Figure 4-1 through Figure 4-3, respectively, show eight-panel displays of afternoon fine particle concentrations as well as surface weather maps and back trajectories from 12Z (8 a.m. EDT) each day. The following chronology of events combines the meteorological insights with $PM_{2.5}$ concentration information to provide a basic storyline for analysis.

A slow-moving high pressure system centered over the Great Lakes set up northerly flow over MANE-VU on August 8. The high drifted southeast-ward and became extended over several days bringing high temperatures to the region. Calm conditions west of MANE-VU on August 10 were pivotal in the formation of fine aerosol concentrations, which began building in the Ohio River Valley. Over the next four days, concentrations in MANE-VU climbed into the 60-90 $\mu g/m^3$ range over a wide area before being swept out to sea by a series of frontal passages beginning on August 15.

8/8 – A high pressure system over the Great Lakes produces NW-N prevailing surface winds (~4-8 mph) throughout the region. Maximum daily temperatures approach or exceed 80° F.

8/9 – Wind speeds fall off but direction remains NW-N as the high moves into the central portion of MANE-VU. Temperatures rise as cloud cover declines.

8/10 – The high reaches the East Coast and stalls. Temperatures (except in northern-most areas) reach 90° F while surface-level winds turn to more southerly directions. Calm conditions through the morning hours in the lower Ohio River Valley promote creation of haze noted in surface observations.

8/11 – Circulation around the high (now near Cape Hatteras) becomes well established. Peak temperatures are in the low to mid-90's. Morning winds are light-to-calm in the area east of the Mississippi – the area of haze now reaches from Michigan to northern Texas and eastward to West Virginia and eastern Tennessee. A surface-level trough descends from north of the Great Lakes during the day, passes eastward through the Ohio River Valley and stalls over the Allegheny Mountains and southward.

8/12 – Temperatures exceed 90º F throughout MANE-VU except in coastal ME. The area of concentrated haze has pushed eastward and now extends from central ME to central PA. Haze builds throughout the day as circulation forces it to channel NE between the stalled trough and a cold front approaching from the Midwest.

8/13 – Calm conditions prevail as the trough reaches coastal NJ by 8 a.m. Generally clear skies allow temperatures to reach the mid-90's everywhere except in coastal ME. Dew points, which had been rising since 8/8, reach the upper 60's. Peak hourly fine aerosol concentrations are greater than 40 $\mu g/m^3$ everywhere in MANE-VU and exceed 90 $\mu g/m^3$ in some locations. By 8 p.m., showers associated with the approaching cold front have reached into Ohio.

8/14 – By 8 a.m. the trough has dissipated and the high is moving offshore. Dew points remain in the upper 60's and peak temperatures reach into the 90's everywhere and top 100 in several locations. Increased ventilation causes aerosol concentrations to drop throughout the day everywhere except ME where some locations peak above 60 $\mu g/m^3$ after midnight.

8/15 – The approaching cold front and associated showers fall apart during the morning hours. By 8 p.m., a new batch of moderate rain has intruded deeply into the region from the SW and has virtually pushed the haze out of the MANE-VU region.

8/16 – A new high building in over the upper Midwest pushes the remains of the showers out of the Northeast.

Figure 4-1. Spatially interpolated maps of fine particle concentrations August 9 – 16, 2002

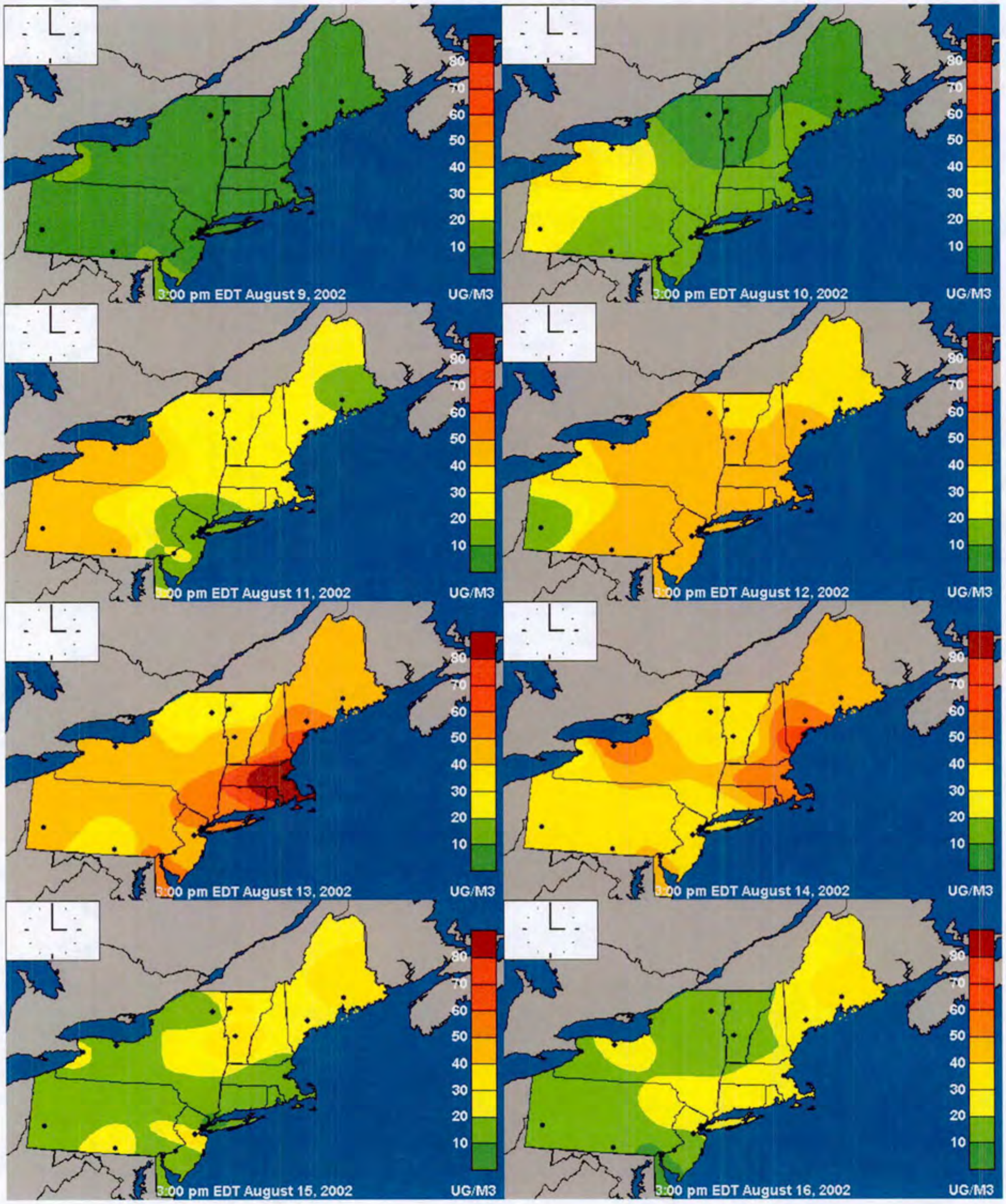


Figure 4-2. Surface weather maps for August 9-16, 2002

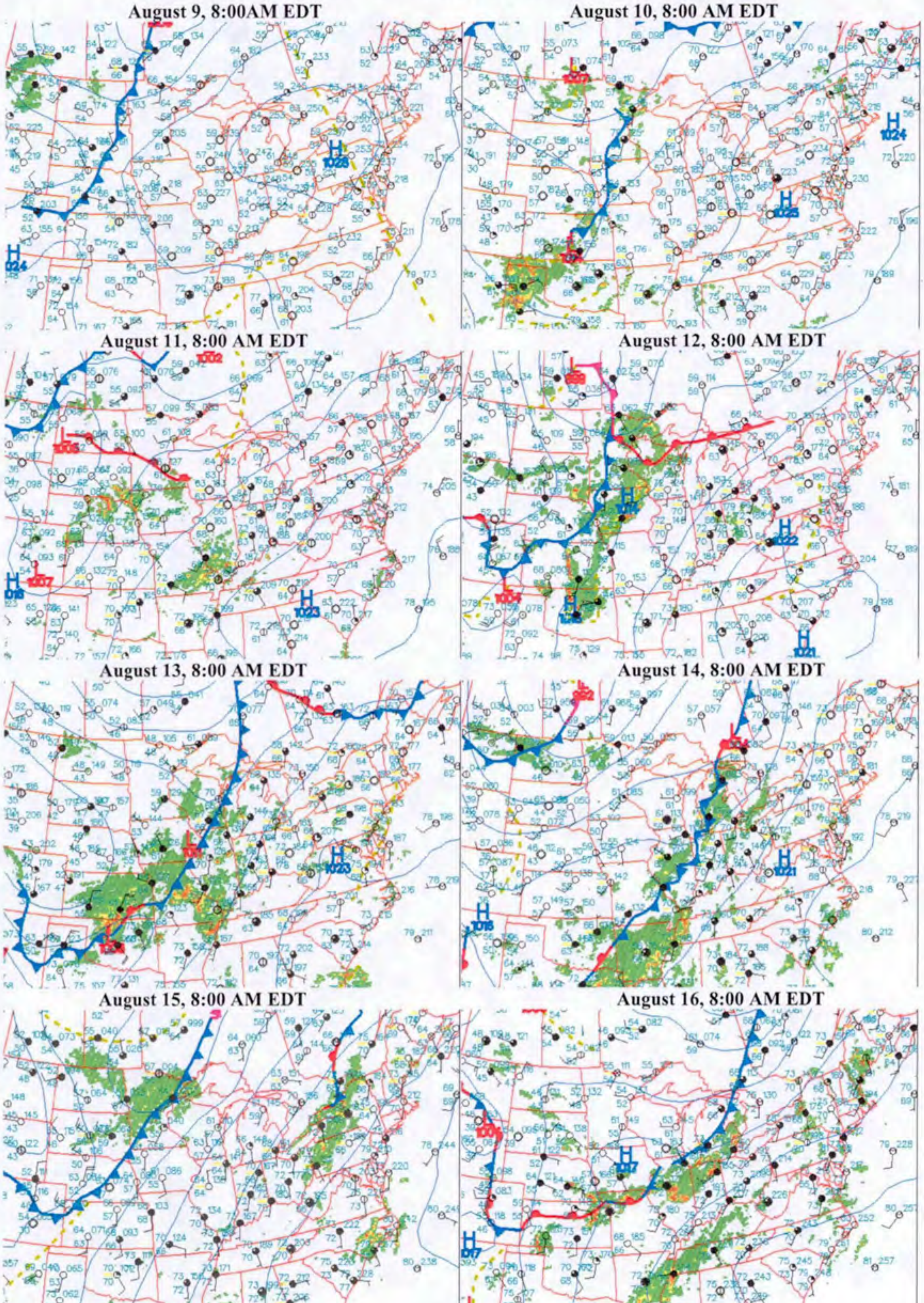
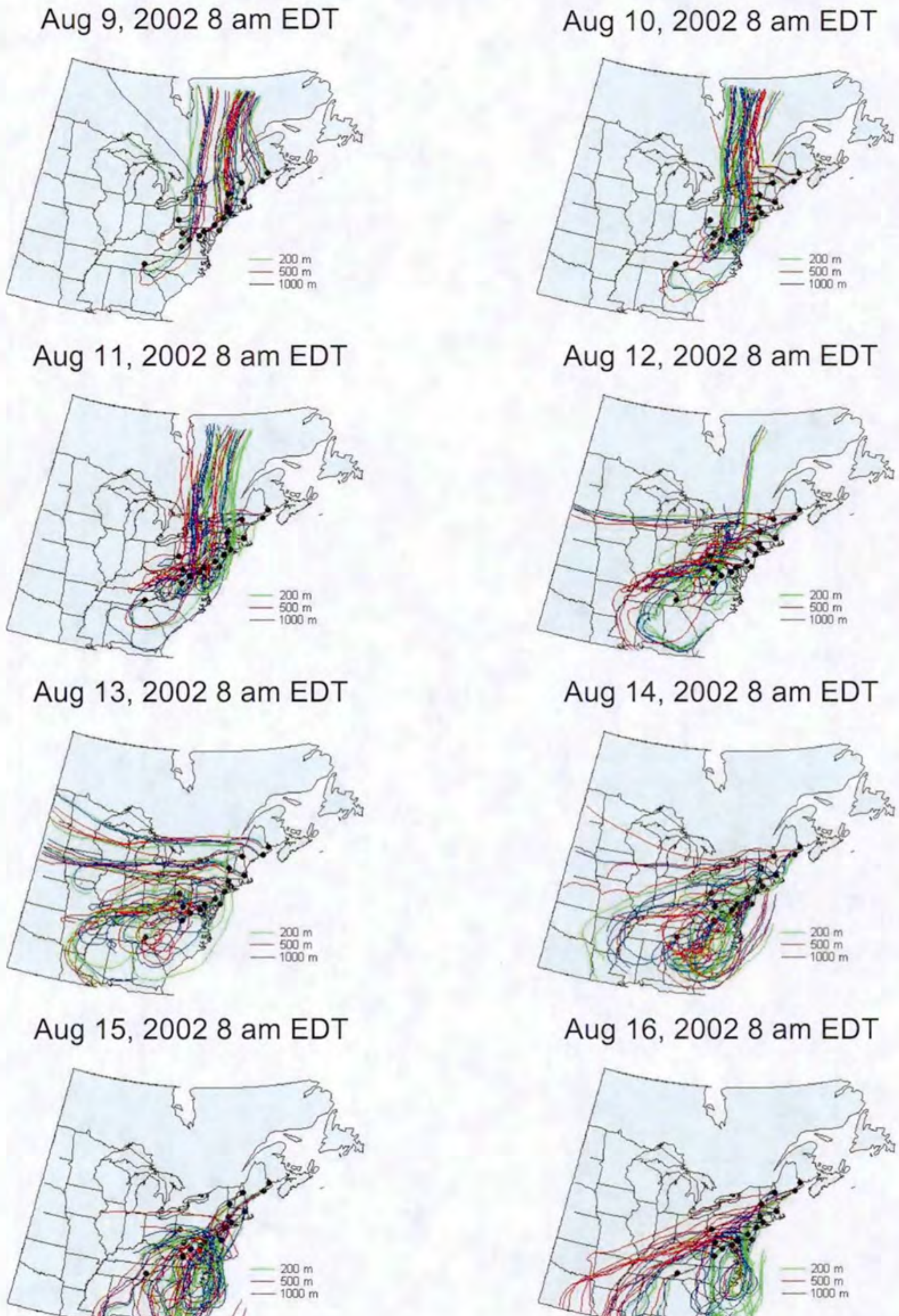


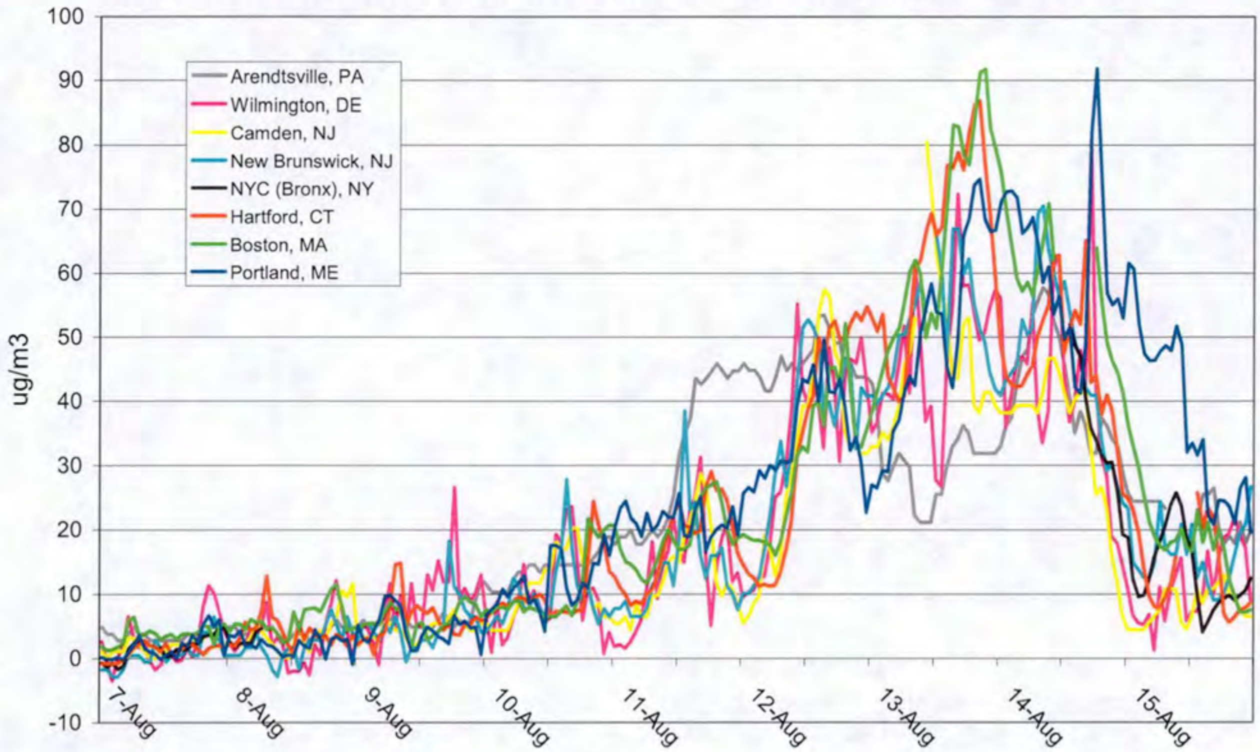
Figure 4-3. HYSPLIT 72-hour back trajectories for August 9-16, 2002



4.2. Temporally and spatially resolved $PM_{2.5}$ measurements

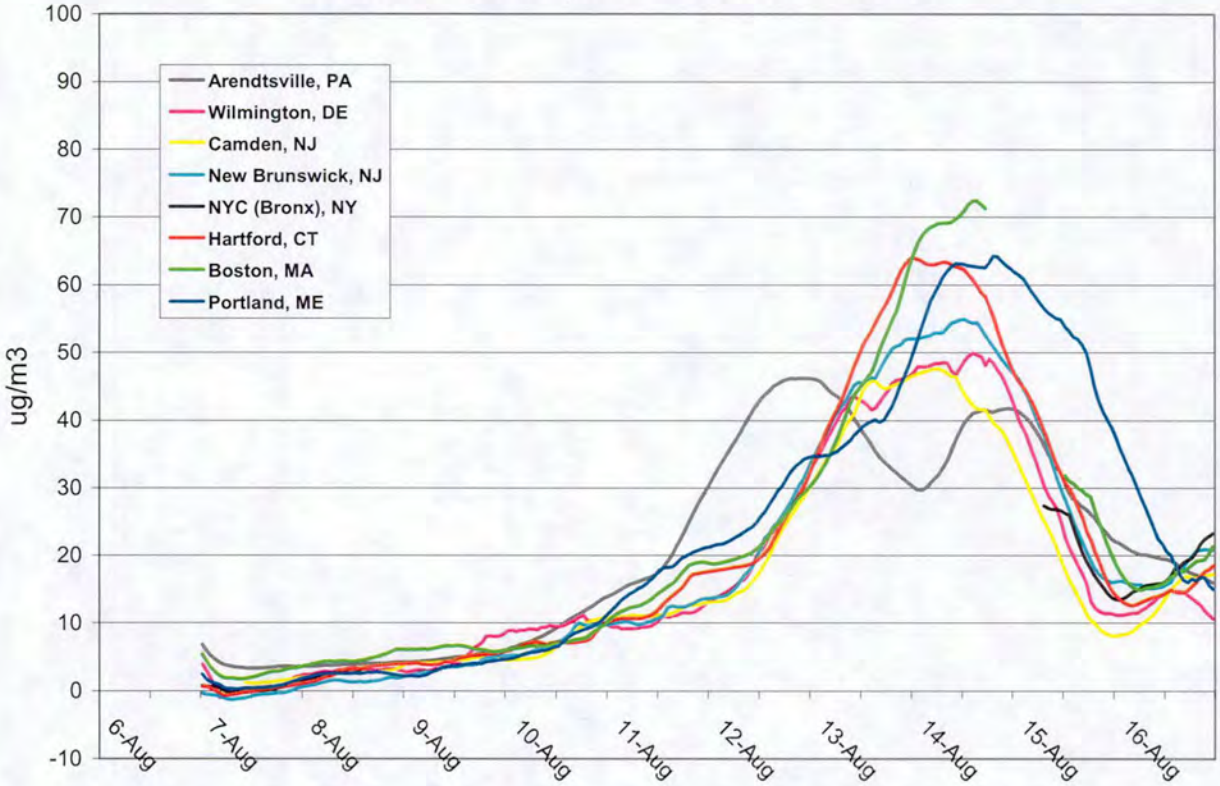
Higher temporal resolution data provide insight into how the events played out in much more detail than can be captured by eight frames on a page; however the most complete picture is obtained when these high *temporal* resolution data can be presented in the context of the relatively greater *spatial* detail provided by maps such as we have seen in Figure 4-1 through Figure 4-3. In Figure 4-4 and Figure 4-5, we present continuous $PM_{2.5}$ data (hourly average and 24-hour rolling average filtered, respectively) for the August 8-16, 2002 time period.

Figure 4-4. Hourly average fine aerosol at 8 sites during the August 2002 episode



Looking at Figure 4-4 in the context of the maps presented in the earlier figures, it is interesting to note the rapid increase, first, in Arendtsville, PA at noon on the 11th, followed by a rise in concentrations along the East Coast around noon on the 12th. This is consistent with Figure 4-1, which shows high $PM_{2.5}$ levels covering western Pennsylvania by 3 p.m. on the 11th and that high $PM_{2.5}$ area has moved over to cover the East Coast by 3 p.m. the next day. This also makes sense with respect to Figure 4-2 and Figure 4-3, which show the high pressure system established on the East Coast by the 11th with surface level back trajectories having shifted from northerly flow to slow southwesterly flow in the western portion of the domain by the morning of the 11th and the coastal sites having switched by the morning of the 12th.

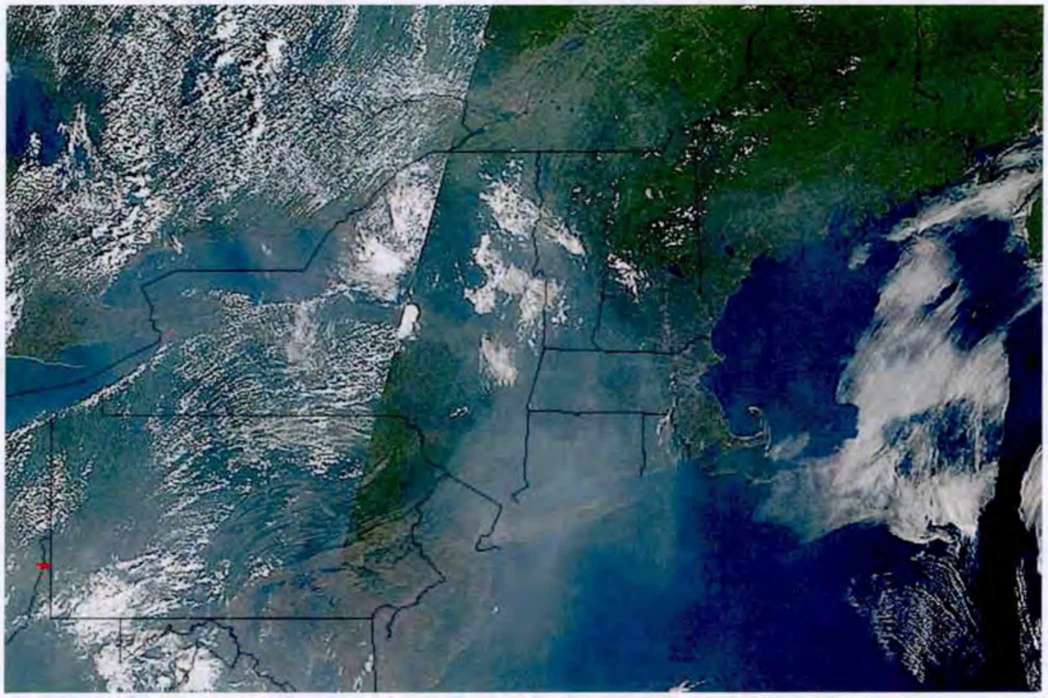
Figure 4-5. 24-hour rolling average fine aerosol at 8 MANE-VU sites during the August 2002 episode



Also note the very high levels observed close to mid-day on the 13th at sites between New York City and Portland, Maine. This is consistent with the strong gradients shown for 3 p.m. on the 13th in Figure 4-1. These rapid increases in concentration are easily explained by the back trajectories of Figure 4-3 that show the advancing front (at this point over Lake Michigan) beginning to push, at upper levels of the atmosphere, an air mass from the upper Midwest due east across the northern half of MANE-VU. At lower levels (see 200 meter trajectories), it can be seen that closer to the surface, this air mass had spent the previous three to four days winding around the Tennessee and Ohio River Valleys before it was driven into the northern reaches of MANE-VU at the peak of the pollution event.

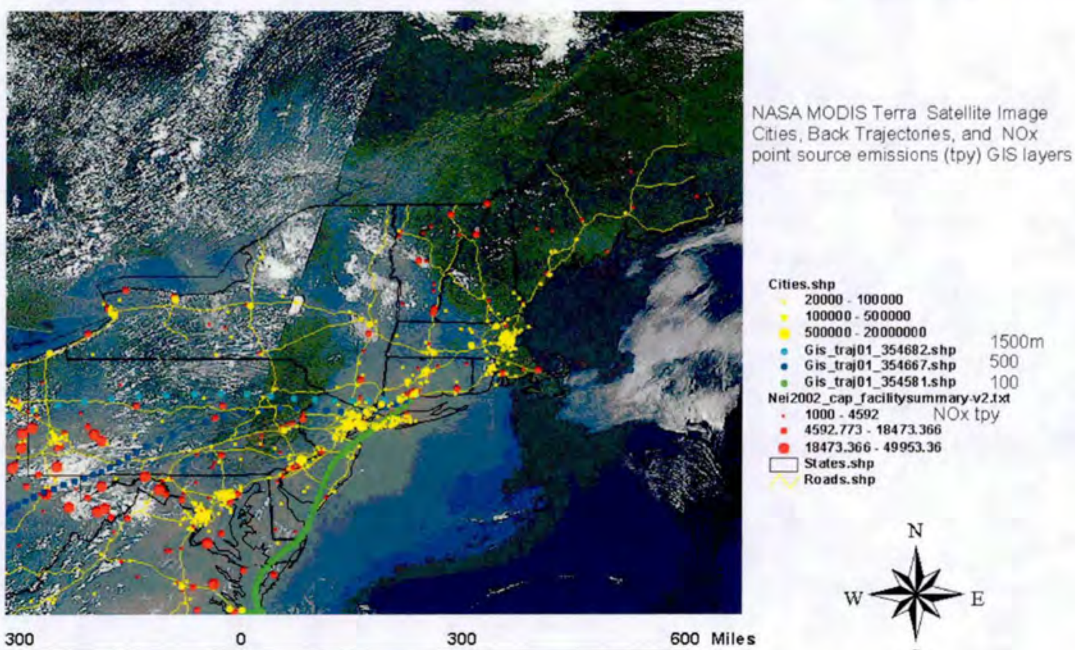
The following figures bring much of this information together in a single image. Figure 4-6 contains satellite photos from MODIS, a mosaic of two consecutive satellite passages on August 13, 2002 from NASA's TERRA satellite. Figure 4-7 shows the same image with geo-referenced activity data and inventory information layered on top to allow for simultaneous depiction of cities, roads, point source emissions, and back trajectories that play a role in the air pollution/haze that affected a large part of the Northeast during this episode.

Figure 4-6. Composite images from NASA's TERRA Satellite on August 13, 2002 showing fine particle pollution/haze.



Note the milky/gray haze due to particle pollution as distinct from the puffy white clouds over broad regions of southern New England and the eastern Mid-Atlantic region.

Figure 4-7. NASA MODIS Terra Satellite Image, Back Trajectories and NO_X Inventory



Geo-referenced activity and inventory data (on top of the satellite images presented above) demonstrating the relationship between observed pollution and upper level winds (driving weather patterns from West to East), mid-level winds (tracking back to major point sources), and lower level winds (tracking back to major population centers along the East Coast).

4.3. Implications for control strategies

A 2003 assessment of fine particulate matter by NARSTO[15] states, "[c]urrent air-quality management approaches focusing on reductions of emissions of SO_2, NO_X, and VOCs are anticipated to be effective first steps towards reducing $PM_{2.5}$ across North America, noting that in parts of California and some eastern urban areas VOC (volatile organic compounds) emissions could be important to nitrate formation."

This conclusion seems to be well supported by the historical record which documents a pronounced decline in particulate sulfate concentrations across the eastern United States during the 1990s. The timing of this observed decline suggests that this is linked to reductions in SO_2 emissions resulting from controls implemented under the federal Acid Rain program beginning in the early to mid-1990s. From 1989 to 1998, SO_2 emissions in the eastern half of the country — that is, including all states within a region defined by the western borders of Minnesota and Louisiana — declined by about 25 percent. This decline in SO_2 emissions correlated with a decline of about 40 percent in average SO_2 and sulfate concentrations, as measured at Clean Air States and Trend Networks (CASTNet) monitoring sites in the same region over the same time period. In fact, at prevailing levels of atmospheric SO_2 loading, the magnitudes of the emissions and concentration changes were not statistically different. This finding suggests that regional reductions in SO_2 emissions have produced near-proportional reductions of particulate sulfate in the eastern United States (NARSTO, 2003). Reductions since 1990 in precursor SO_2 emissions are likely also responsible for a continued decline in median sulfate concentrations in the northeastern United States. Nevertheless, episodes of high ambient sulfate concentrations (with peak levels well above the regional median or average) continue to occur, especially during the summertime when regional transport from the Ohio River Valley is also at its peak. This suggests that further reductions in regional and local SO_2 emissions would provide significant further air quality and visibility benefits (NARSTO, 2003).

For urban areas of the eastern United States, an effective emissions management approach may be to combine regional SO_2 control efforts aimed at reducing summertime $PM_{2.5}$ concentrations with local SO_2 and OC control efforts. Local SO_2 reductions would help reduce wintertime $PM_{2.5}$ concentrations, while OC reductions can help reduce overall $PM_{2.5}$ concentrations year-round. For areas with high wintertime $PM_{2.5}$ levels, strategies that involve NO_X reductions may also be effective (NARSTO, 2003).

Further support for this general approach may be found in a review of several studies by Watson (2002) which concluded that SO_2 emission reductions have in most cases been accompanied by statistically significant reductions in ambient sulfate concentrations. One study (Husar and Wilson, 1993) shows that regionally averaged light extinction closely tracks regionally averaged SO_2 emissions for the eastern United States from 1940 through the mid-1980s. Another study by Malm *et al.* (2002) shows that

[15] NARSTO was formerly an acronym for the "North American Research Strategy for Tropospheric Ozone." More recently, the term NARSTO became simply a wordmark signifying a tri-national, public-private partnership for dealing with multiple features of tropospheric pollution, including ozone and suspended particulate matter. For more information on NARSTO see http://www.cgenv.com/Narsto/.

regionally averaged emissions and ambient concentrations decreased together from 1988 through 1999 over a broad region encompassing the states of Connecticut, Delaware, Illinois, Indiana, Kentucky, Maine, Massachusetts, Maryland, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, Wisconsin, and West Virginia (Watson, 2002).

These studies and available data from the IMPROVE (Interagency Monitoring of Protected Visual Environment) monitoring network provide strong evidence that regional SO_2 reductions have yielded, and will continue to yield, reductions in ambient secondary sulfate levels with subsequent reductions in regional haze and associated light extinction. They indicate that reductions in anthropogenic primary particle emissions will also result in visibility improvements, but that these will not have a zone of influence as large as those of the secondary aerosols (Watson, 2002).

Watson (2002) notes that during the 65 years in which the regional haze program aims to reach its final visibility goals, several opportunities to revise this basic control approach will arise through the decadal SIP cycle. This enables new scientific results to continue to exert a positive influence as states implement new regulatory control programs for SO_2, NO_X and VOCs, and as ambient concentrations of these pollutants change relative to each other and relative to ambient ammonia levels. As these relationships between species change, atmospheric chemistry may dictate a revised control approach to those previously described. Further research on these issues should be a priority for supporting 2018 SIP submissions. They include the possibility that:

- Reduction of sulfate in a fully neutralized atmosphere (excess ammonia) could encourage ammonium nitrate formation.
- Ever-greater emissions reductions could be required to produce a given level of improvement in ambient pollutant concentrations because of non-linearities in the atmospheric formation of sulfate.
- Changes in ambient conditions favoring the aqueous oxidation of sulfate (this pathway largely accounts for the non-linearity noted above) may have implications for future emissions control programs. Causes of changing ambient conditions could include, for example, climate change.

West *et al.* (1999) examine a scenario for the eastern United States where $PM_{2.5}$ mass decreases linearly with ammonium sulfate until the latter is fully neutralized by ammonia. Further reductions would free ammonia for combination with gaseous nitric acid that, in turn, would slightly increase $PM_{2.5}$ until all of the nitric acid is neutralized and further sulfate reductions are reflected in lower $PM_{2.5}$ mass. This is an extreme case that is more relevant to source areas (e.g., Ohio) where nitric acid (HNO_3) is more abundant than in areas with lower emissions (e.g., Vermont) (Watson, 2002).

In most situations with non-neutralized sulfate (typical of the eastern United States), ammonia is a limiting agent for the formation of nitrate but will not make any difference until sulfate is reduced to the point where it is completely neutralized. At that point, identifying large sources of ammonia emissions will be important. This point is likely to be many years in the future, however (Watson, 2002).

Based on analyses using the Community Multi-Scale Air Quality (CMAQ) model, the aqueous phase production of sulfate in the Northeast appears to be very oxidant limited and hence non-linear. Thus, conditions that are conducive to a dominance of the gas-phase production pathway drive the summer peaks in ambient sulfate levels. Nonetheless, the expected reduction in ambient sulfate levels resulting from a given reduction in SO_2 emissions is less than proportional overall due to the non-linearity introduced by the aqueous pathway for sulfate formation (NARSTO, 2003). These non-linearity effects are more pronounced for haze than for sulfate deposition, especially at higher sulfate air concentrations (USNPS, 2003).

Finally, we note that because visibility in the clearest areas is sensitive to even minute increases in particle concentrations, strategies to preserve visibility on the clearest days may require stringent limits on emissions growth. In this context, even the dilute emissions from distant sources can be important (NARSTO, 2003)

4.4. Conclusion: Simplifying a complex problem

A conceptual understanding of fine particles from a regional perspective across MANE-VU and throughout the eastern U.S. is well understood, yet remains complex due to the multiplicity of source regions (both regional and local), pollutants (SO_2, NO_X, organic carbon, and primary $PM_{2.5}$), and seasons (summer and winter) that are involved in fine particle formation.

Regional approaches to the control of precursor SO_2 and NO_X emissions have been started through Title IV of the Clean Air Act, the NO_X SIP Call, the CAIR, and the establishment and support of Regional Planning Organizations to assist with Regional Haze Rule compliance. With the modeling foundation developed for the CAIR program, the USEPA has presented a compelling technical case on the need for additional regional SO_2 and NO_X reductions in the eastern U.S. to reduce particulate levels and protect public health. While states in the Northeast disagree with the extent of SO_2 and NO_X reductions and the timeline for those reductions to occur, the program is an excellent next step toward reducing fine particles in MANE-VU. It is tempting to suggest that the regional control of SO_2 and NO_X are the extent of the problem facing MANE-VU, but as the conceptual description contained in this report demonstrates, the reduction of fine particles in the eastern U.S. requires a careful balance of regional and local controls for SO_2, NO_X, sources of organic carbon and primary $PM_{2.5}$ during both summer and winter.

The (relatively) higher emissions of SO_2 and NO_X from regions upwind of MANE-VU as well as the long "reach" of sulfate pollution requires continued regional control of these fine particle precursors. However, local accumulation of SO_2-derived sulfate, NO_X-derived nitrate, and primary PM (mostly in the form of black carbon/diesel exhaust) can significantly boost urban $PM_{2.5}$ levels. Residential wood combustion in rural river valleys can significantly raise PM levels as well and affect rural visibility in areas near to Class I areas.

The balance between regional and local controls parallels the balance that needs to be achieved between pollutants. The regional contribution to fine particle pollution is driven by sulfates and organic carbon, whereas the local contribution to $PM_{2.5}$ is derived from SO_2, NO_X, organic carbon, and primary $PM_{2.5}$ (including black carbon/diesel exhaust).

Finally, control strategies which focus on regional SO_2 emissions reductions are needed throughout the summer and winter months, suggesting that a year-round approach to control is needed. Urban nonattainment counties with local emissions of NO_X and VOC will be driven to reduce these emissions during the summer for ozone benefits, but these same pollutants – as well as primary particulate emissions – contribute to high $PM_{2.5}$ levels in winter, suggesting that annual controls for all of these pollutants make sense in a multi-pollutant context. Finally, residential wood smoke near Class I areas is clearly a winter-only issue, and further controls may be desirable near specific Class I sites where organic carbon is a contributor on the 20 percent worst visibility days that occur in winter months.

To bring attainment to the current fine particle nonattainment counties and meet reasonable progress goals toward national visibility goals, there continues to be a need for more regional SO_2 and NO_X reductions coupled with appropriate local SO_2, NO_X, VOC, and primary $PM_{2.5}$ (including diesel exhaust) controls where local accumulation is shown to add to the regional burden of sulfate and nitrate $PM_{2.5}$ (primarily in winter). These local controls will vary by location and by season, but the regional control of SO_2 and NO_X should be maintained on an annual basis given the contribution of regional sulfate and nitrate to fine particle peaks during both summer and winter months.

Appendix A: Excerpts from EPA Guidance Document, Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze

APPENDIX A: EPA GUIDANCE DOCUMENT EXERPT

11.0 How Do I Get Started? - A "Conceptual Description"

A State/Tribe should start developing information to support a modeled attainment demonstration by assembling and reviewing available air quality, emissions and meteorological data. Baseline design values should be calculated at each monitoring site, as described in Section 3. For PM applications, speciated data should be reviewed to get a sense of what component(s) might be contributing most significantly to nonattainment or light extinction. If past modeling has been performed, the emission scenarios examined and air quality predictions may also be useful. Readily available information should be used by a State/Tribe to develop an initial conceptual description of the nonattainment or reasonable haze problem in the area which is the focus of a modeled demonstration. A conceptual description is instrumental for identifying potential stakeholders and for developing a modeling/analysis protocol. It may also influence a State's choice of air quality model, modeling domain, grid cell size, priorities for quality assuring and refining emissions estimates, and the choice of initial diagnostic tests to identify potentially effective control strategies. In general, a conceptual description is useful for helping a State/Tribe identify priorities and allocate resources in performing a modeled demonstration.

In this Section, we identify key parts of a conceptual description. We then present examples of analyses which could be used to describe each of these parts. We note that initial analyses may be complemented later by additional efforts performed by those implementing the protocol.

11.1 What Is A "Conceptual Description"?

A "conceptual description" is a qualitative way of characterizing the nature of an area's nonattainment or regional haze problem. It is best described by identifying key components of a description. Examples are listed below. There are 3 different examples. One each for ozone, annual $PM_{2.5}$, and regional haze. The examples are not necessarily comprehensive. There could be other features of an area's problem which are important in particular cases. For purposes of illustration later in the discussion, we have answered each of the questions posed below. Our responses appear in parentheses.

11.1.1 8-Hour Ozone NAAQS

1. Is the nonattainment problem primarily a local one, or are regional factors important?
(Surface measurements suggest transport of ozone close to 84 ppb is likely. There are some other nonattainment areas not too far distant.)

2. Are ozone and/or precursor concentrations aloft also high?
(There are no such measurements.)

3. Do violations of the NAAQS occur at several monitoring sites throughout the nonattainment area, or are they confined to one or a small number of sites in proximity to one another?
(Violations occur at a limited number of sites, located throughout the area.)

4. Do observed 8-hour daily maximum ozone concentrations exceed 84 ppb frequently or just on a few occasions?
(This varies among the monitors from 4 times up to 12 times per year.)

5. When 8-hour daily maxima in excess of 84 ppb occur, is there an accompanying characteristic spatial pattern, or is there a variety of spatial patterns?
(A variety of patterns is seen.)

6. Do monitored violations occur at locations subject to mesoscale wind patterns (e.g., at a coastline) which may differ from the general wind flow?
(No.)

7. Have there been any recent major changes in emissions of VOC or NO_X in or near the nonattainment area? If so, what changes have occurred?
(Yes, several local measures [include a list] believed to result in major reductions in VOC [quantify in tons per summer day] have been implemented in the last five years. Additionally, the area has seen large regional NO_X reductions from the NO_X SIP call.)

8. Are there discernible trends in design values or other air quality indicators which have accompanied a change in emissions?
(Yes, design values have decreased by about 10% at four sites over the past [x] years. Smaller or no reductions are seen at three other sites.)

9. Is there any apparent spatial pattern to the trends in design values?
(No.)

10. Have ambient precursor concentrations or measured VOC species profiles changed?
(There are no measurements.)

11. What past modeling has been performed and what do the results suggest?
(A regional modeling analysis has been performed. Two emission scenarios were modeled: current emissions and a substantial reduction in NO_X emissions throughout the regional domain. Reduced NO_X emissions led to substantial predicted reductions in 8-hour daily maximum ozone in most locations, but changes near the most populated area in the nonattainment area in question were small or nonexistent.)

12. Are there any distinctive meteorological measurements at the surface or aloft which appear to coincide with occasions with 8-hour daily maxima greater than 84 ppb?
(Other than routine soundings taken twice per day, there are no measurements aloft. There is no obvious correspondence with meteorological measurements other than daily maximum temperatures are always > 85 F on these days.)

Using responses to the preceding questions in this example, it is possible to construct an initial conceptual description of the nonattainment area's ozone problem. First, responses to questions 1 and 11 suggest there is a significant regional component to the area's nonattainment problem. Second, responses to questions 3, 4, 7, 8, and 11 indicate there is an important local component to the area's nonattainment problem. The responses to questions 4, 5 and 12 indicate that high ozone concentrations may be observed under several sets of meteorological conditions. The responses to questions 7, 8, and 11 suggest that ozone in and near the nonattainment area may be responsive to both VOC and NO_X controls and that the extent of this response may vary spatially. The response to question 6 suggests that it may be appropriate to develop a strategy using a model with 12 km grid cells.

The preceding conceptual description implies that the State/Tribe containing the nonattainment area in this example will need to involve stakeholders from other, nearby States/Tribes to develop and implement a modeling/analysis protocol. It also suggests that a nested regional modeling analysis will be needed to address the problem. Further, it may be necessary to model at least several distinctive types of episodes and additional analyses will be needed to select episodes. Finally, sensitivity (i.e., diagnostic) tests, or other modeling probing tools, will be needed to assess the effects of reducing VOC and NO_X emissions separately and at the same time.

11.1.2 Annual $PM_{2.5}$ NAAQS

1. Is the nonattainment problem primarily a local one, or are regional factors important? (Surface measurements suggest that only design values in or immediately downwind of the city violate the NAAQS. However, other nearby design values come close to the concentration specified in the NAAQS)

2. What is the relative importance of measured primary and secondary components of $PM_{2.5}$ measured at sites violating the NAAQS?
(Secondary components (i.e., SO_4, NO_3, OC) constitute about 80% of the measured mass of $PM_{2.5}$. There are higher concentrations of primary $PM_{2.5}$ in the core urban area compared to the suburbs and more rural areas.)

3. What are the most prevalent components of measured $PM_{2.5}$?
(The most important components in ranked order are mass associated with SO_4, OC and inorganic primary particulate matter (IP)).

4. Does the measured mix of PM components appear to roughly agree with mix of emission categories surrounding the monitoring sites?
(No. Relative importance of measured crustal material (IP) appears less than what might be inferred from the inventory).

5. Do there appear to be any areas with large gradients of primary $PM_{2.5}$ in monitored or unmonitored areas?
(Cannot really tell for sources of crustal material until we resolve the preceding

inventory/monitoring discrepancy. There are no other obvious major sources of primary particulate matter).

6. Is there any indication of what precursor might be limiting formation of secondary particulate matter?
(No indicator species analyses have been performed. Past analyses performed for ozone-related SIP revisions suggest that ozone in this area may be limited by availability of VOC).

7. Do monitored violations occur at locations subject to mesoscale wind patterns (e.g., at a coastline) which may differ from the general wind flow?
(No.)

8. Have there been any recent major changes in emissions of PM or its precursors in or near the nonattainment area? What?
(Yes, measures believed to result in major reductions in VOC and NO_X have been implemented in the last 5 years. Reductions in power plant NO_X have resulted from the NO_X SIP call and SO_2 emissions reductions have resulted from the national program to reduce acid deposition.)

9. Are there discernible trends in design values or other air quality indicators which have accompanied a change in emissions?
(The trend appears to be downward, but the most recent air quality data has been higher. Overall, the period of record is insufficiently long to tell).

10. Is there any apparent spatial pattern to the trends in design values?
(No.)

11. What past modeling has been performed and what do the results suggest?
(A regional modeling analysis has been performed for ozone and $PM_{2.5}$. Two emission scenarios were modeled: current emissions and a substantial reduction in NO_X and SO_2 emissions throughout a regional domain. Reduced NO_X emissions led to substantial predicted reductions in 8-hour daily maximum ozone in most locations. Modeled SO_2 reductions from the CAIR rule had a strong impact on sulfate concentrations)

12. Are there any distinctive meteorological measurements at the surface or aloft which appear to coincide with occasions with $PM_{2.5}$ concentrations in excess of 15.0 :g/m$_3$?
(Other than routine soundings taken twice per day, there are no measurements aloft. There is no obvious correspondence with meteorological measurements other than daily maximum temperatures are often > 85F on days with the highest $PM_{2.5}$ observations.)

13. Do periods with high measured particulate matter or components of particulate matter appear to track each other or any other measured pollutant?
(There appears to be some correspondence between measured high concentrations of SO_4 and ozone).

Using responses to the preceding questions in this example, it is possible to construct an initial conceptual description of the nonattainment area's ozone problem. First, responses to questions 1, 2 and 3 suggest there is a significant regional component to the area's nonattainment problem. Second, responses to questions 1 and 3 indicate there is a local component to the problem. The responses to questions 11,12 and 13 suggest that there may be a link between reducing ozone and reducing particulate matter. Thus, it may be appropriate to assess effects of previously committed to strategies to reduce ozone and national PM control measures before simulating additional control measures. The responses to questions 4 and 5 suggest that it is premature to determine whether a "local area analysis" will be needed. The response to question 7 suggests that it may not be necessary to model with very small grid cells, at least for the secondary components of $PM_{2.5}$.

The preceding conceptual description implies that the State containing the nonattainment area in this example will need to involve stakeholders from other, nearby States to develop and implement a modeling/analysis protocol. It also suggests that a nested regional modeling analysis will be needed to address the problem.

11.1.3 Example reasonable progress application

1. What components of particulate matter appear to have high concentrations on days with poor visibility?
(Mass associated with SO_4 and coarse particulate matter (CM) seem to have the highest concentrations on most such days).

2. What are typical values for the humidity adjustment factor during the times of year when most of the days with poor visibility occur?
(Typical values appear to be about "4.0").

3. Does visibility appear to track well among nearby Class I areas?
(Yes, but not always).

4. Does poor visibility seem to occur under any specific meteorological conditions?
(This information is not readily available).

5. Does poor visibility seem to coincide with high observed concentrations of any particular other pollutant?
(There seems to be some correspondence with high regional ozone concentrations)

6. What components of particulate matter appear to have relatively high concentrations on days with good visibility?
(Coarse particulate matter and OC)

7. What are typical values for the humidity adjustment factor during times of year when most of the days with good visibility occur?
(About "2.3")

8. Does good visibility appear to occur under any specific meteorological conditions? (Don't know.)

Answers to the preceding questions suggest that strategies to reduce sulfate concentrations and, perhaps, regional ozone concentrations might be effective in reducing light extinction on days when visibility is currently poor. The responses suggest that a strategy which focuses on this alone should first be tried for the days with good visibility as well. Even though sulfate concentrations appear low on such days, the fact that sulfates scatter light efficiently (see Equation (6.1)) and relative humidity is still high enough to enhance this effect is worth considering. Responses suggest that further meteorological analyses would be worthwhile prior to selecting strategies to simulate with a resource intensive regional model.

It should be clear from the preceding examples that the initial conceptual description of an area's nonattainment problem draws on readily available information and need not be detailed. It is intended to help launch development and implementation of a modeling/analysis protocol in a productive direction. It will likely be supplemented by subsequent, more extensive modeling and ambient analyses performed by or for those implementing the modeling/analysis protocol discussed in Section 12.0.

Questions like those posed in Section 11.1 can be addressed using a variety of analyses ranging in complexity from an inspection of air quality data to sophisticated mathematical analyses. We anticipate the simpler analyses will often be used to develop the initial conceptual description. These will be followed by more complex approaches or by approaches requiring more extensive data bases as the need later becomes apparent. These analyses are intended to channel resources available to support modeled attainment demonstrations onto the most productive paths possible. They will also provide other pieces of information which can be used to reinforce conclusions reached with an air quality model, or cause a reassessment of assumptions made previously in applying the model. As noted in Section 7, corroboratory analyses should be used to help assess whether a simulated control strategy is sufficient to meet the NAAQS.

Appendix B: Monitoring Data from Class I sites in MANE-VU

Below are figures that were developed by Tom Downs of the Maine Department of Environmental Protection. These figures represent baseline monitoring data for the Class I sites (and Washington DC) based on IMPROVE monitoring network data using the EPA approved "default" algorithm for calculating reconstructed extinction and estimating natural background conditions. These statistics may need to be recreated using the alternative methodology approved by the IMPROVE steering committee and adopted by the MANE-VU states. Glide path graphs were created on the VIEWS website (http://vista.cira.colostate.edu/views/) using the Annual Summary Trends tool. Seasonal graphs were created from data downloaded from the VIEWS website using the Annual Summary Composition tool and should be updated to include 2004 data for a complete description of regional haze baseline data.

APPENDIX B: MONITORING DATA FROM CLASS I SITES IN MANE-VU

Figure B-1. Monitoring Data from Acadia NP, ME

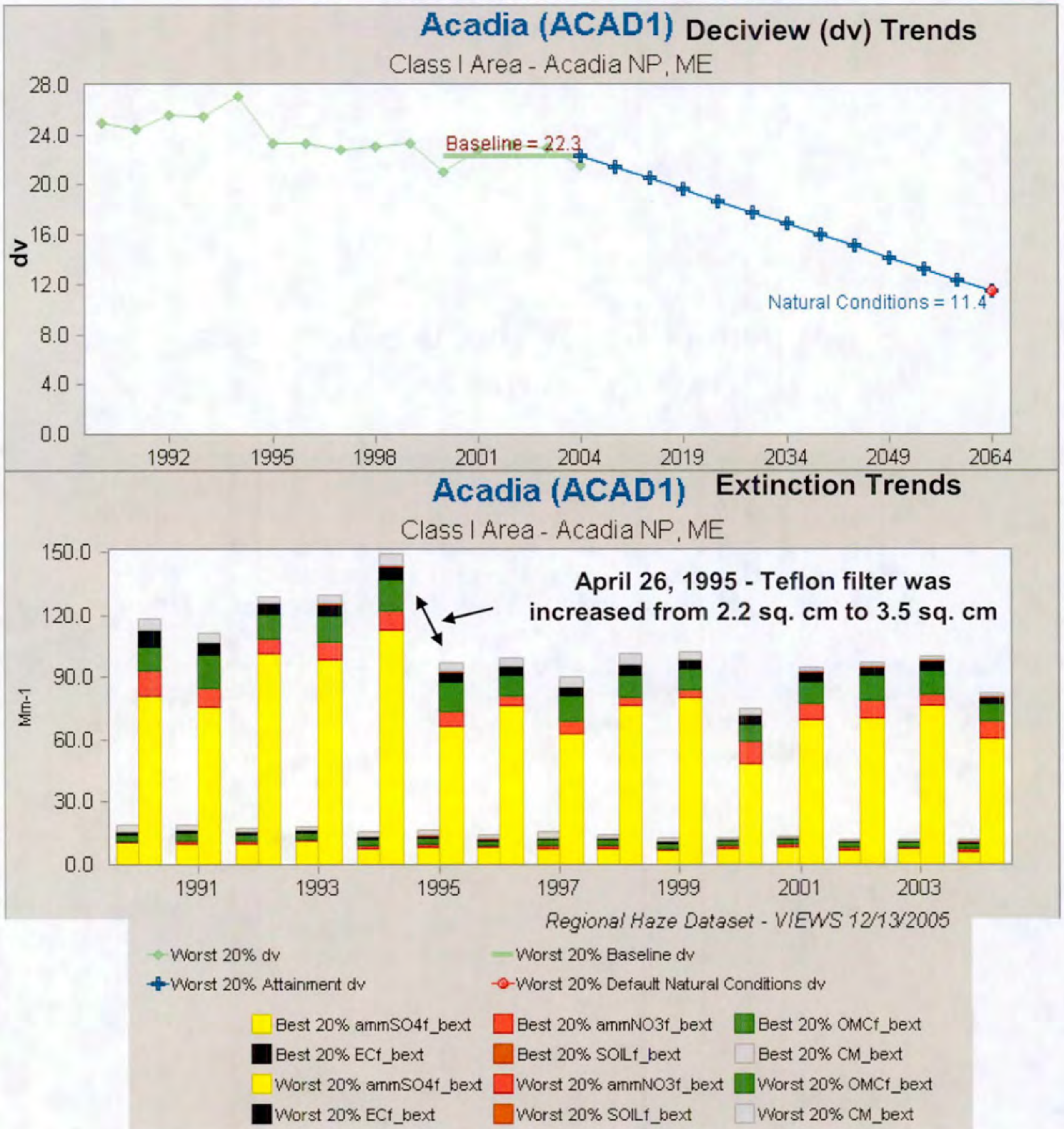


Figure B-2. Monitoring Data from Brigantine, ME

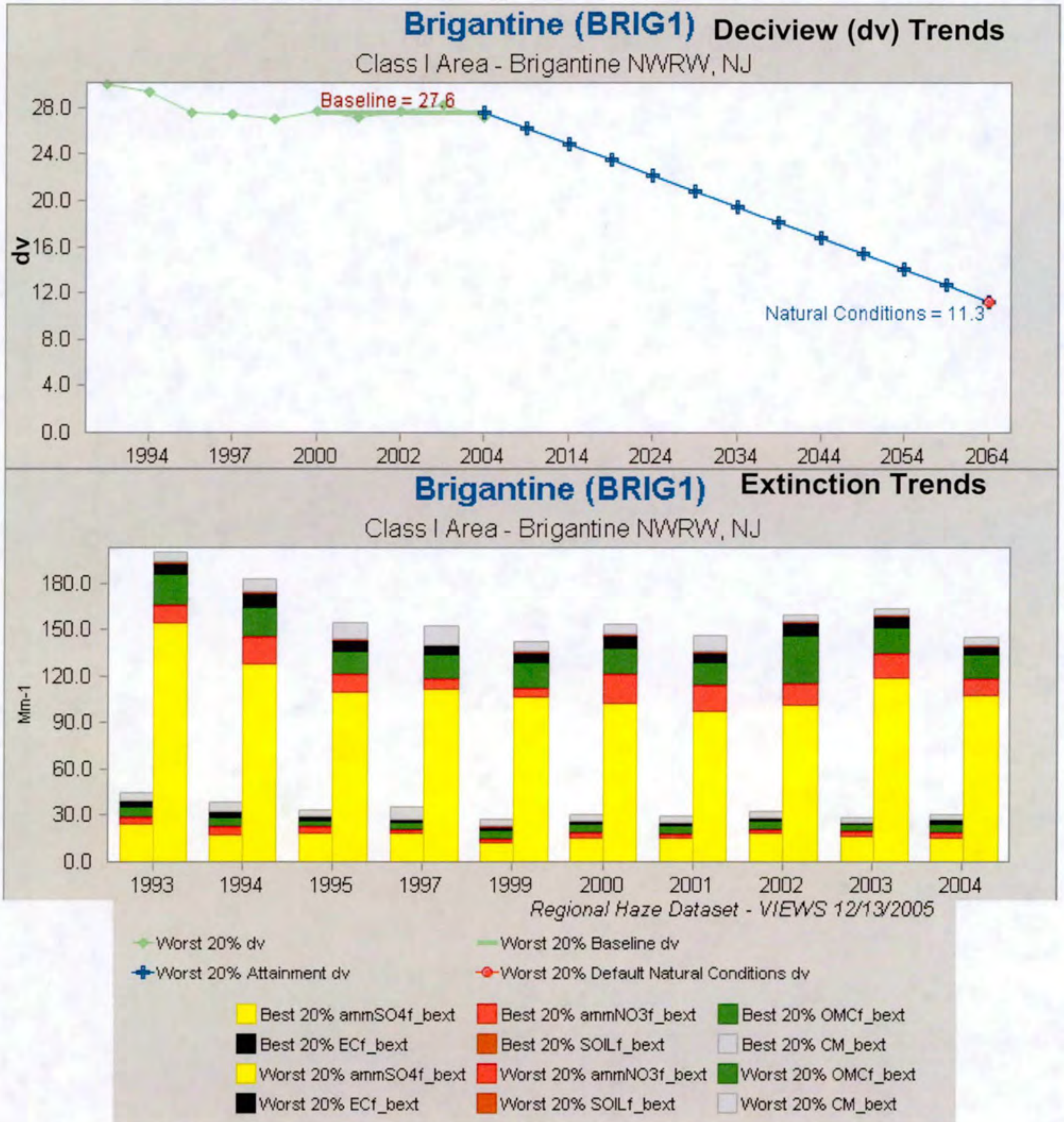


Figure B-3. Monitoring Data from Great Gulf, NH

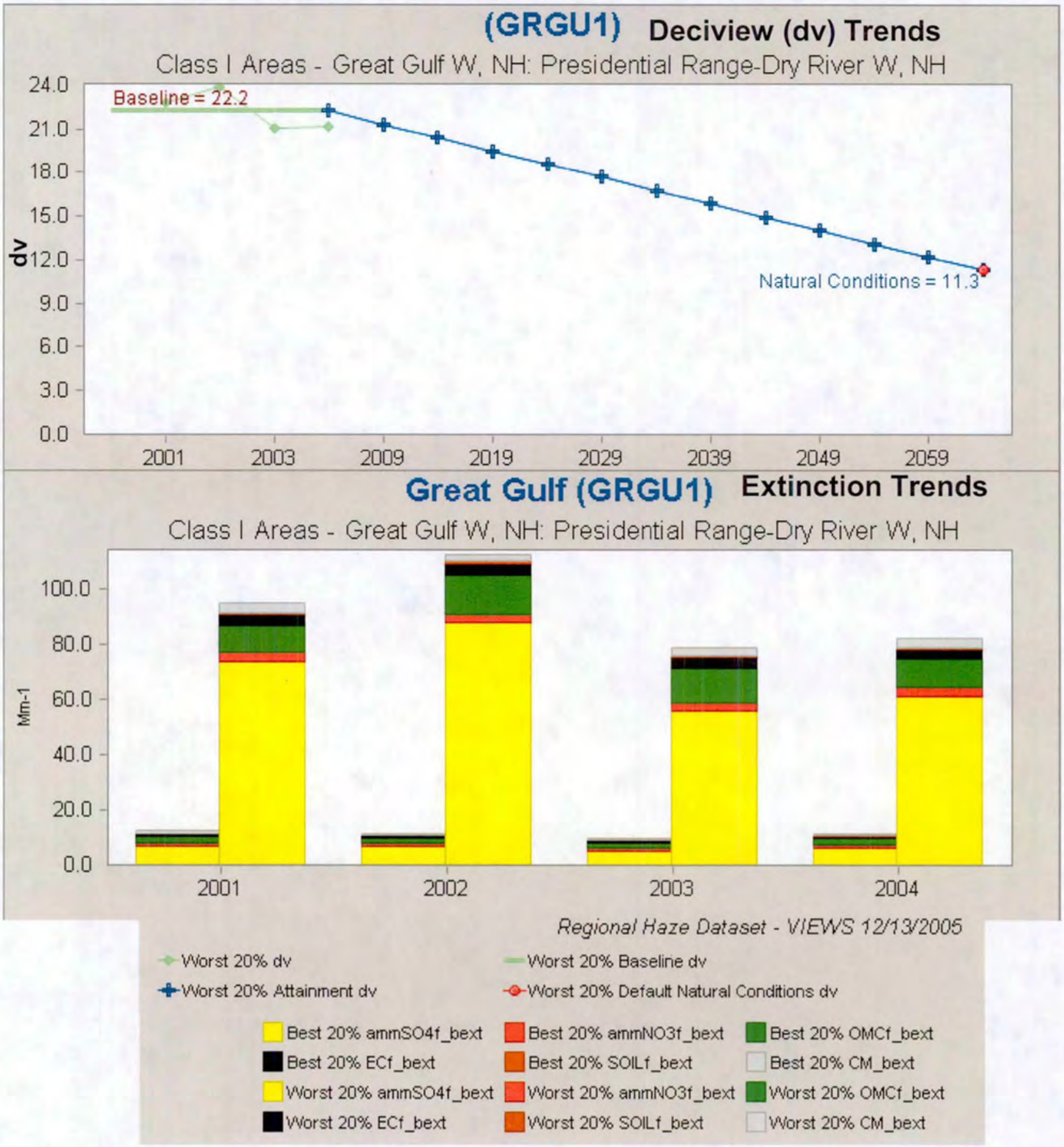


Figure B-4. Monitoring Data from Lye Brook, VT

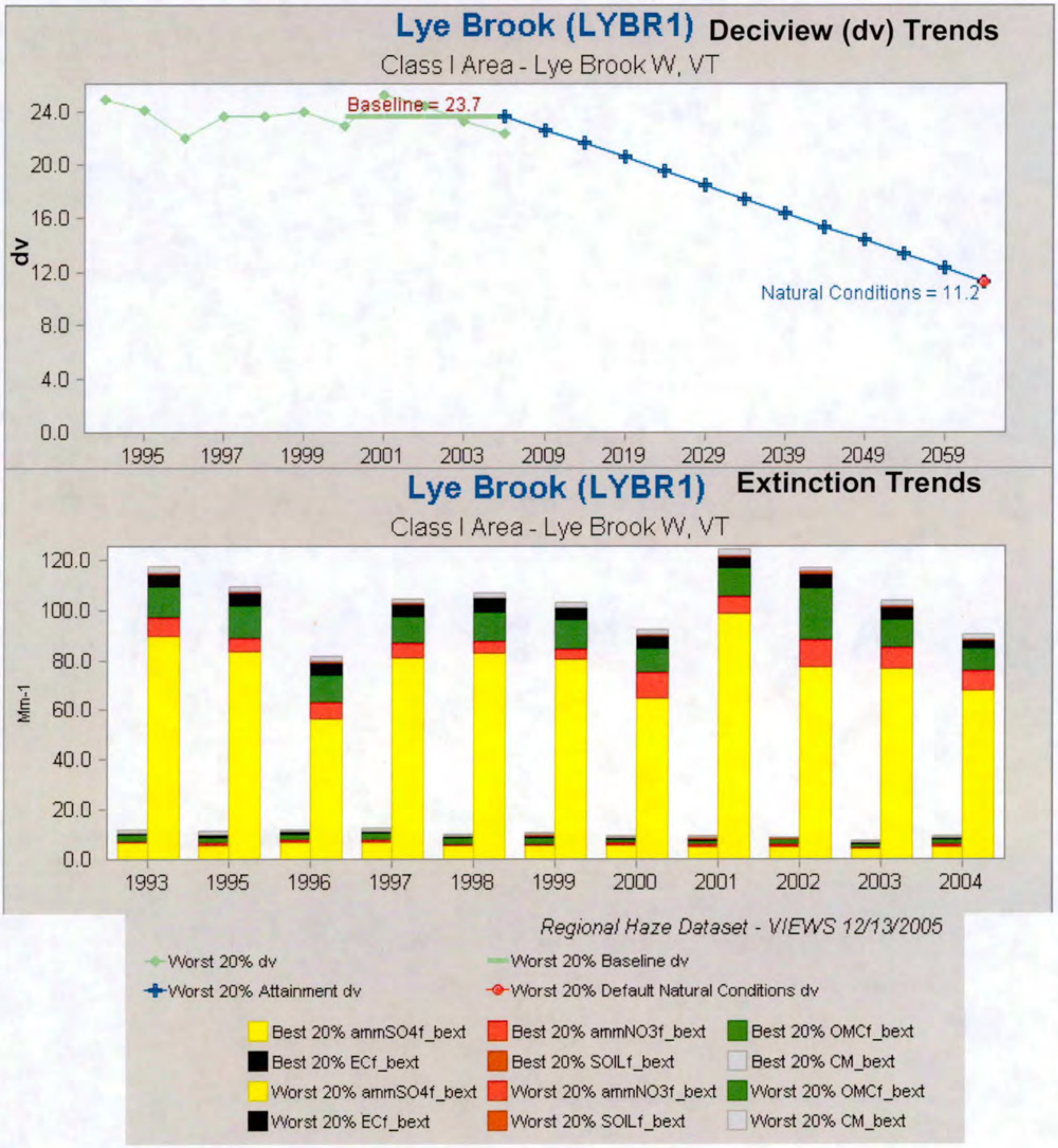


Figure B-5. Monitoring Data from Moosehorn, ME

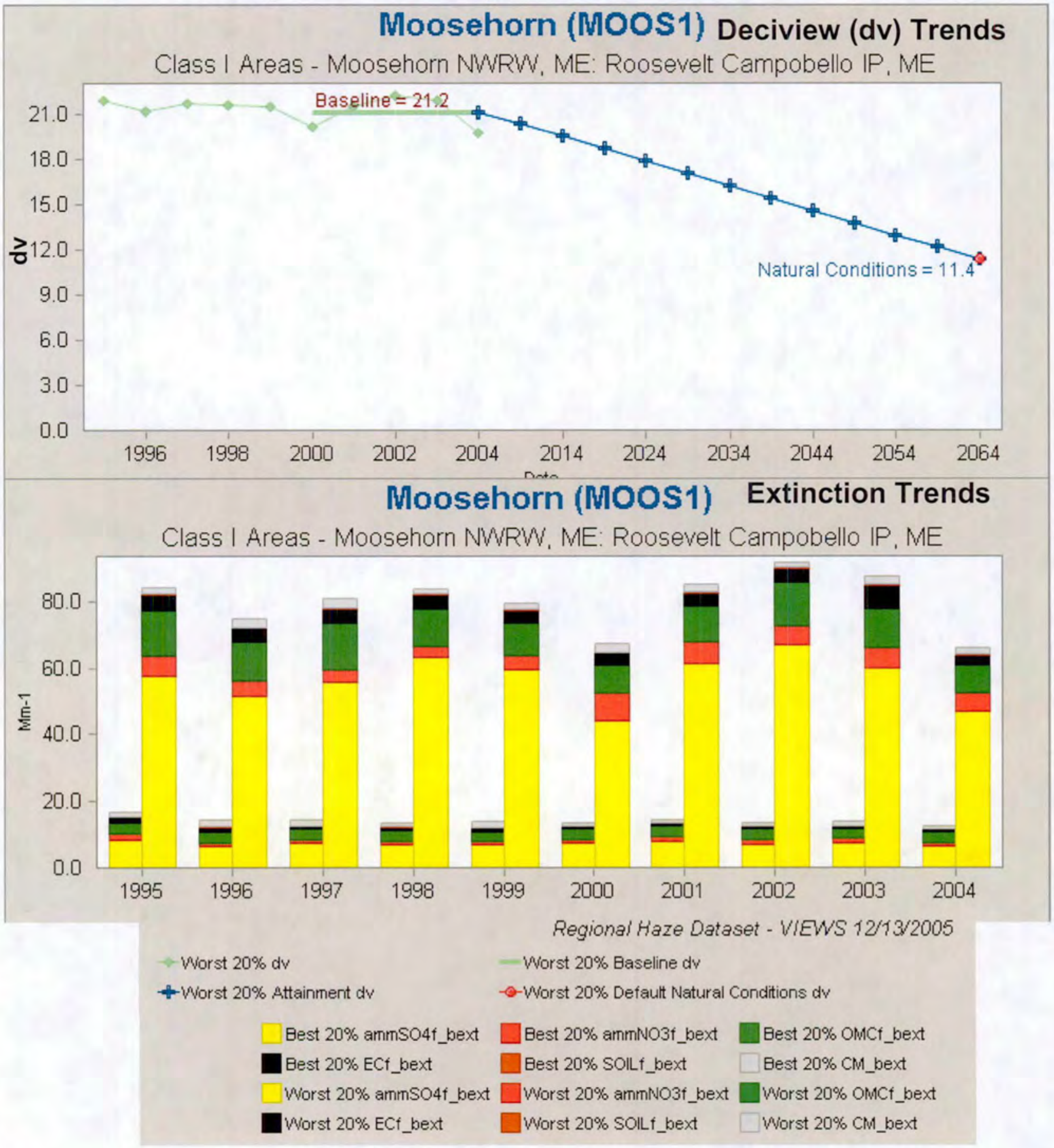


Figure B-6. Monitoring Data from Washington, DC

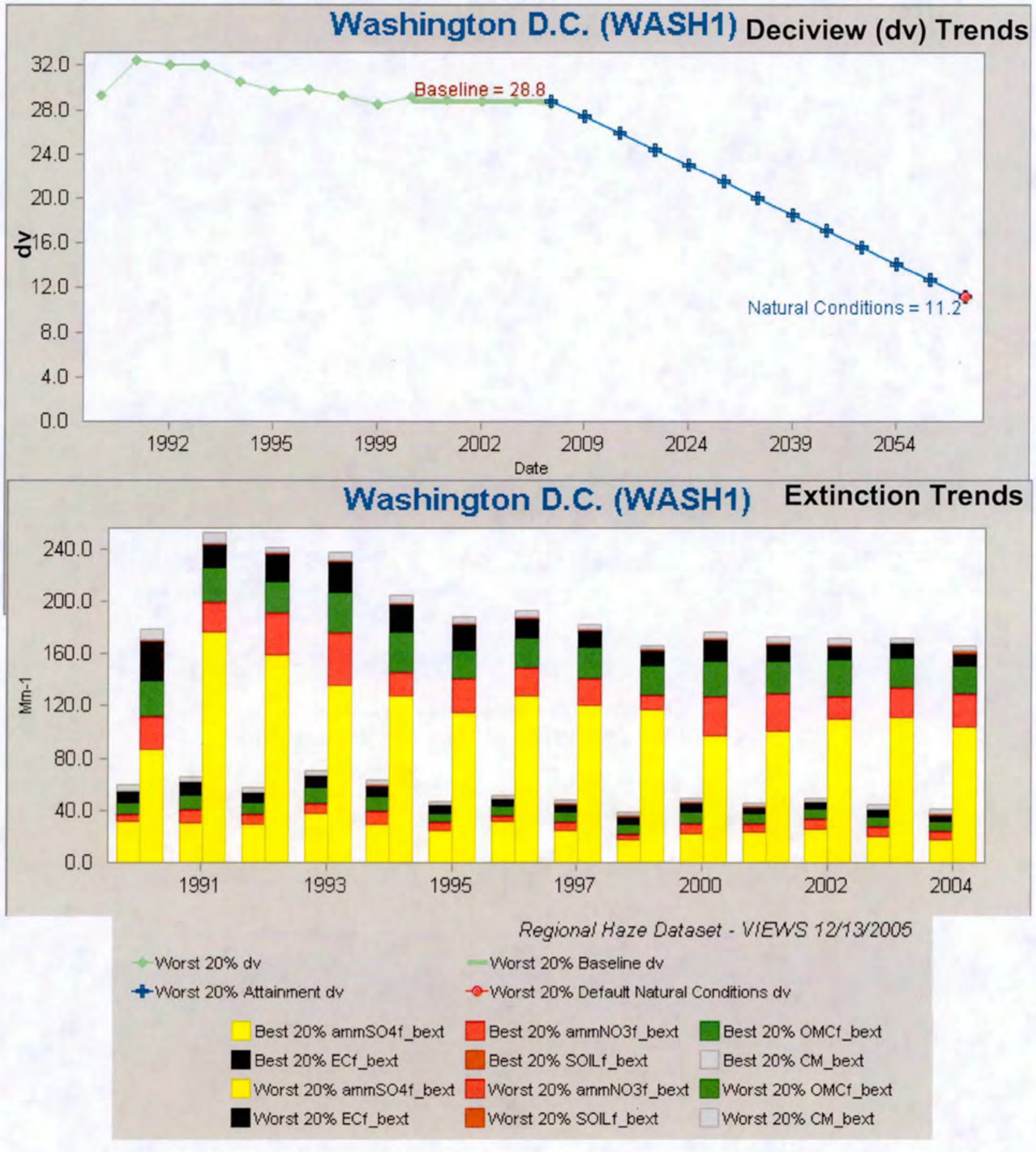
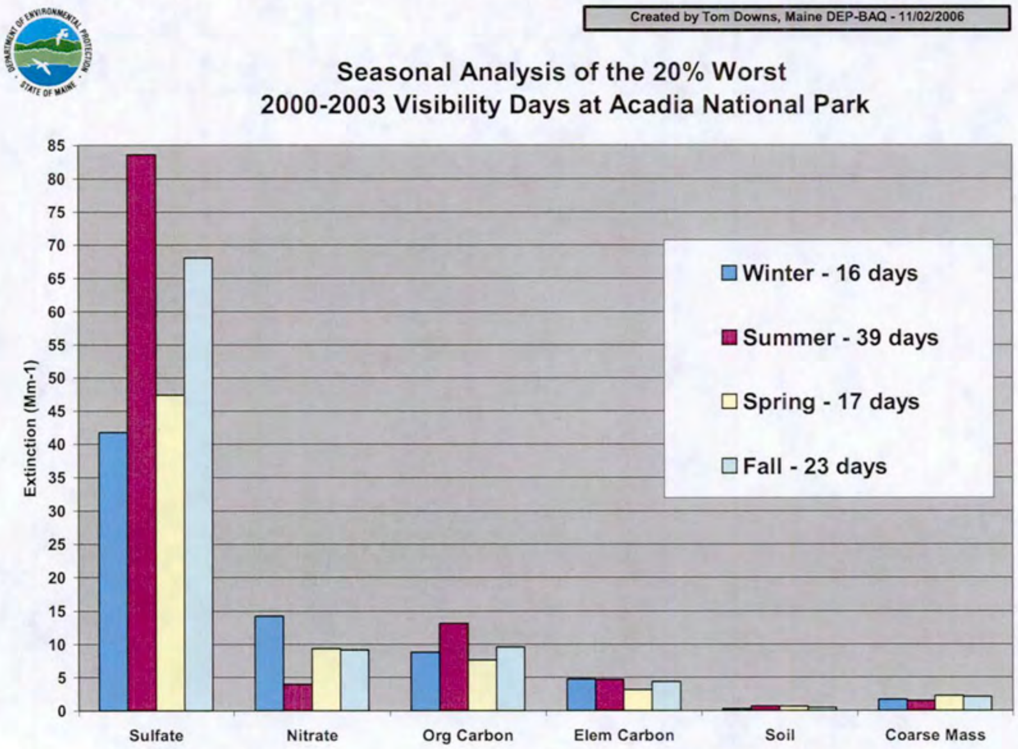


Figure B-7. 20% Worst and Best 2000-2003 Visibility Days at Acadia NP, ME



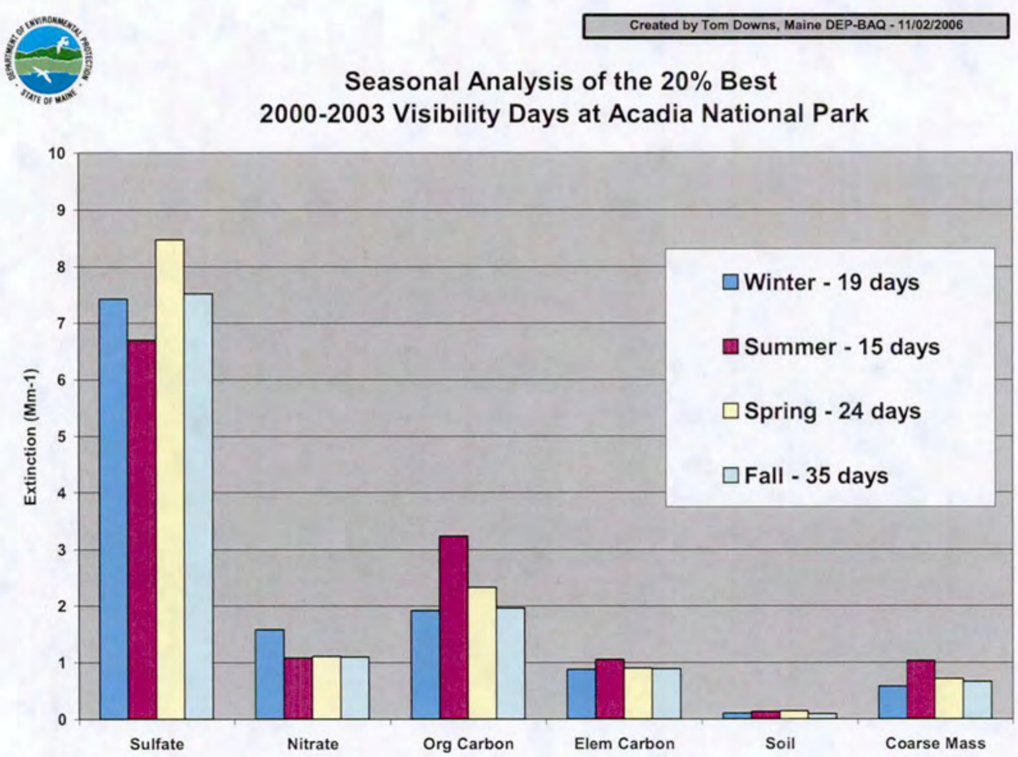
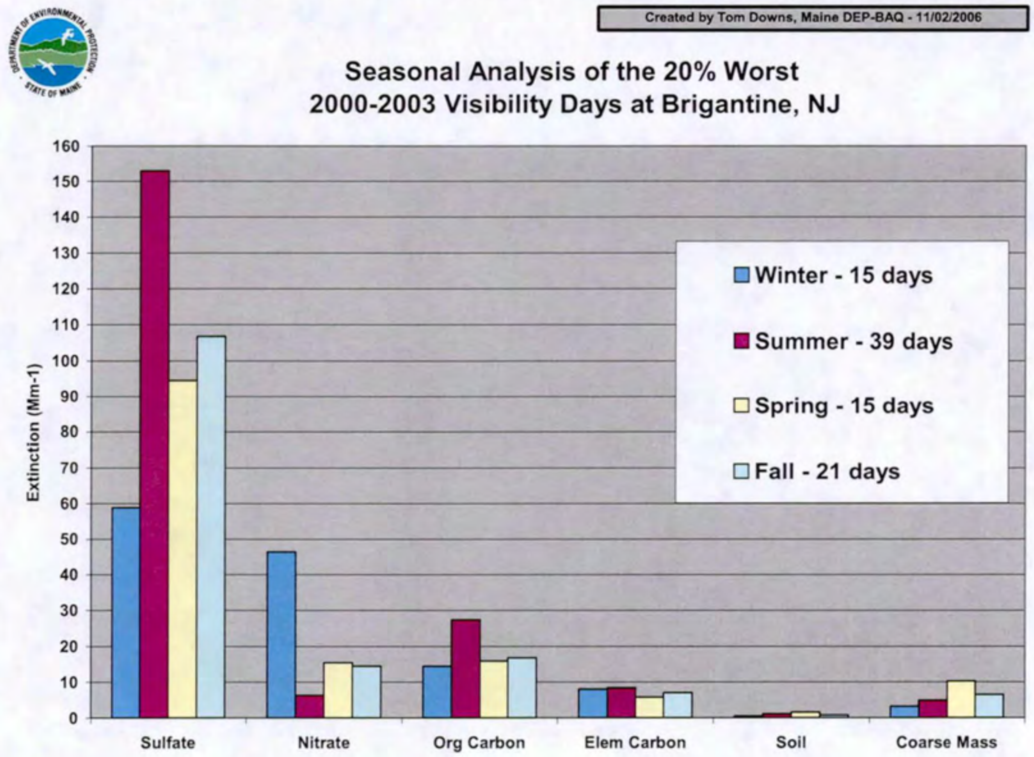


Figure B-8. 20% Worst and Best 2000-2003 Visibility Days at Brigantine, NJ



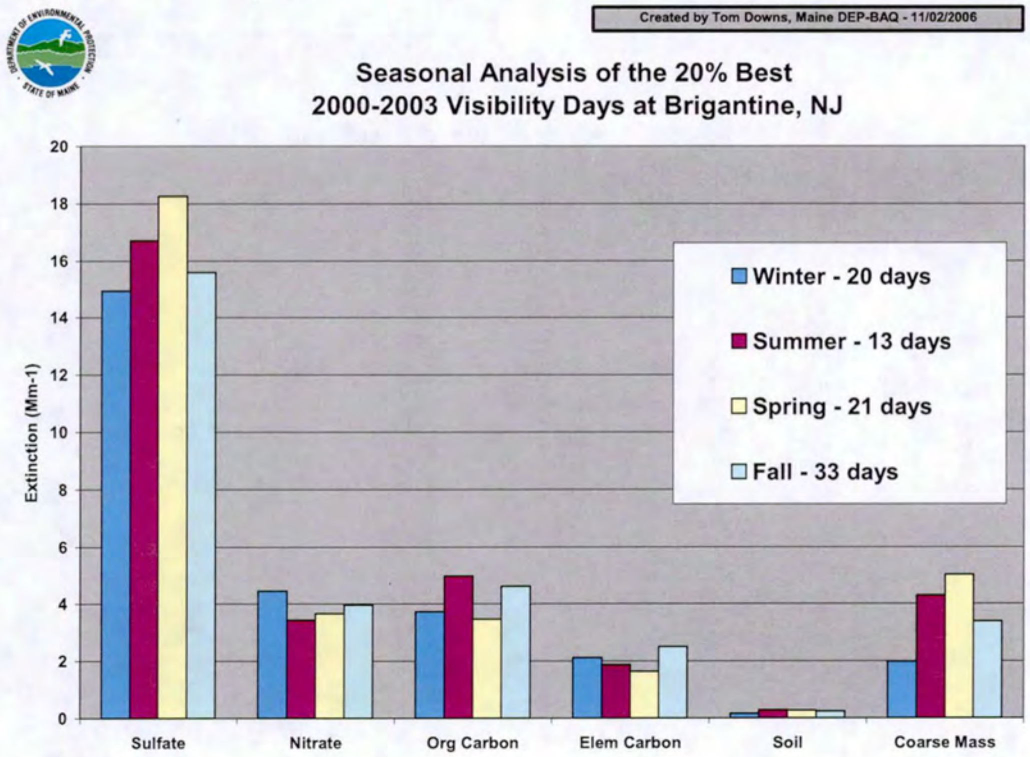
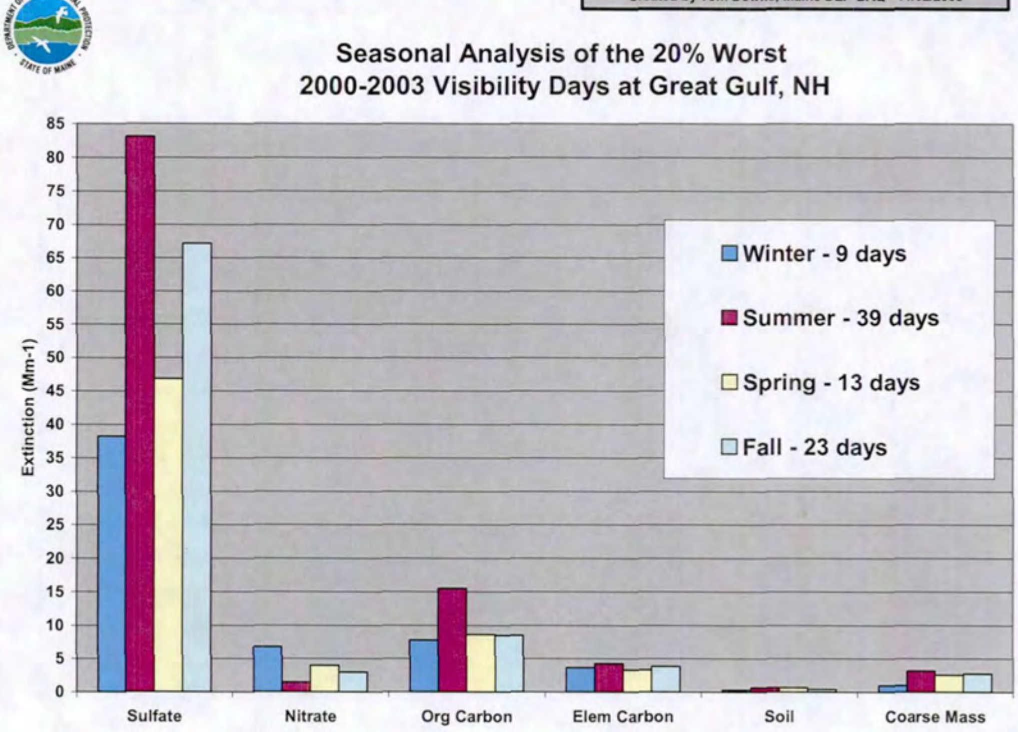


Figure B-9. 20% Worst and Best 2000-2003 Visibility Days at Great Gulf, NH



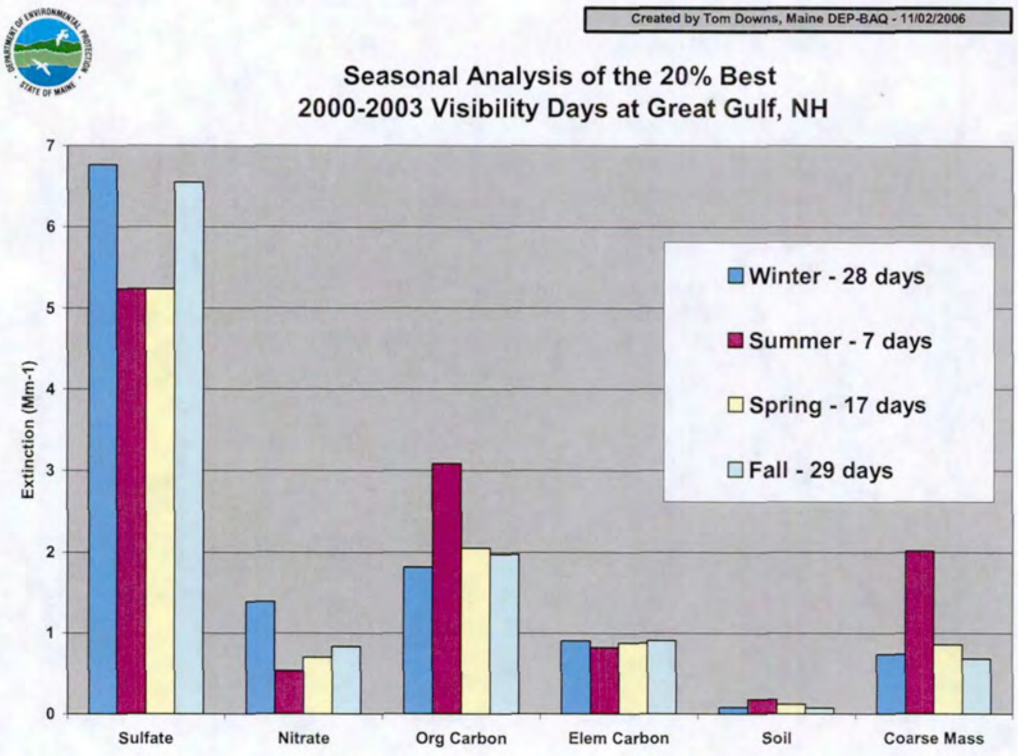
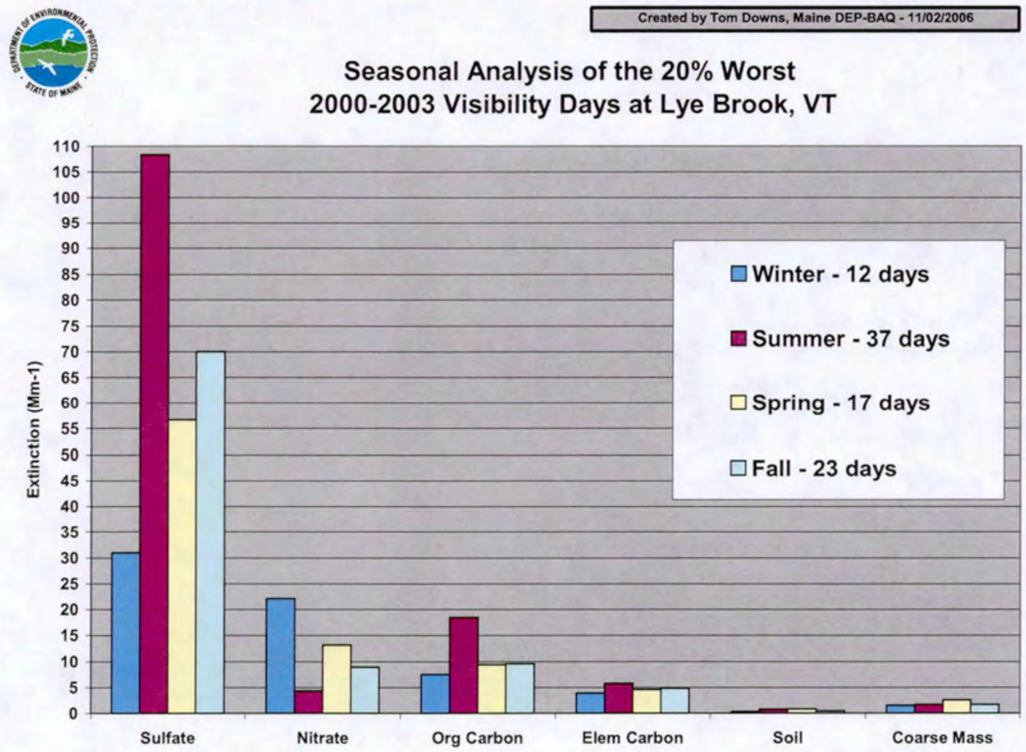


Figure B-10. 20% Worst and Best 2000-2003 Visibility Days at Lye Brook, VT



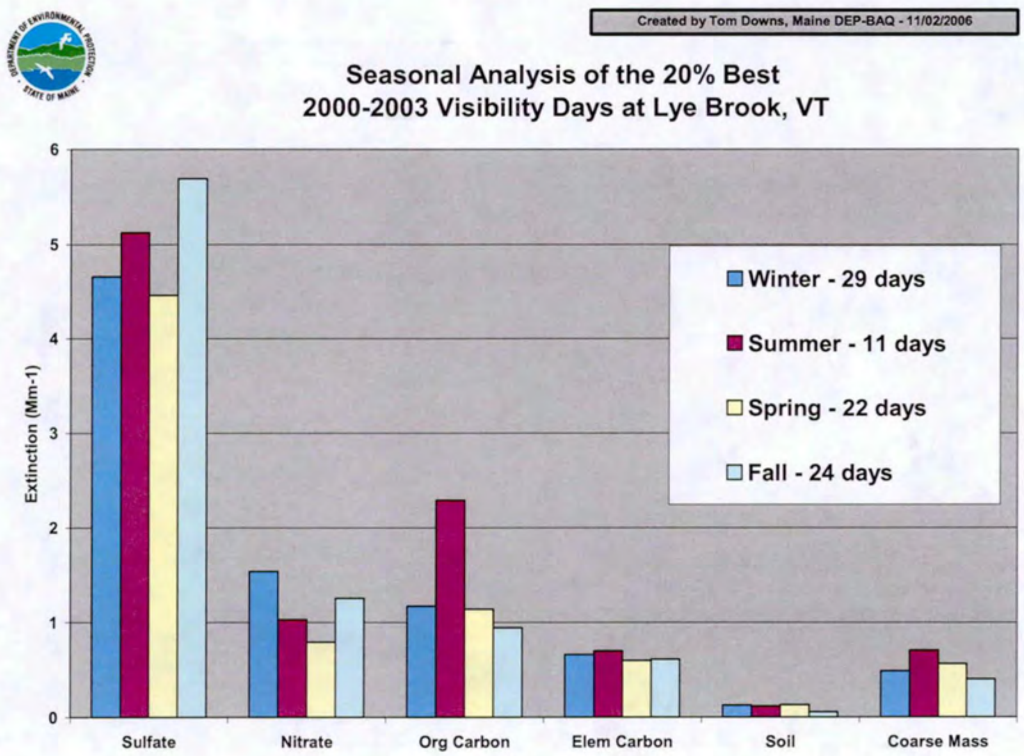
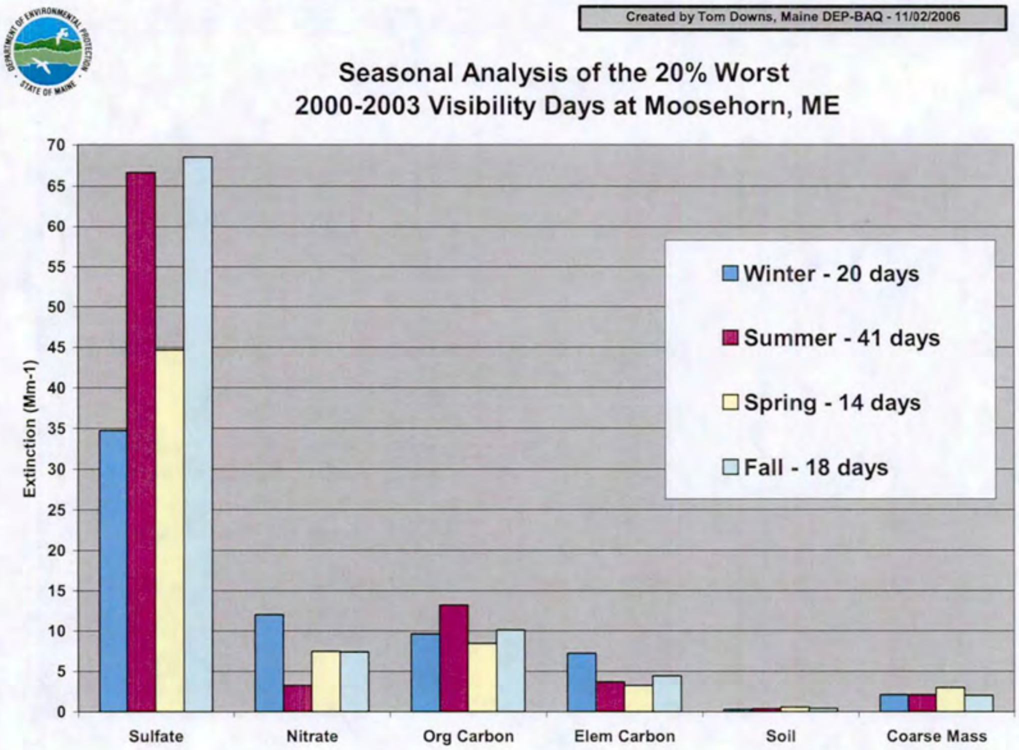


Figure B-11. 20% Worst and Best 2000-2003 Visibility Days at Moosehorn, ME



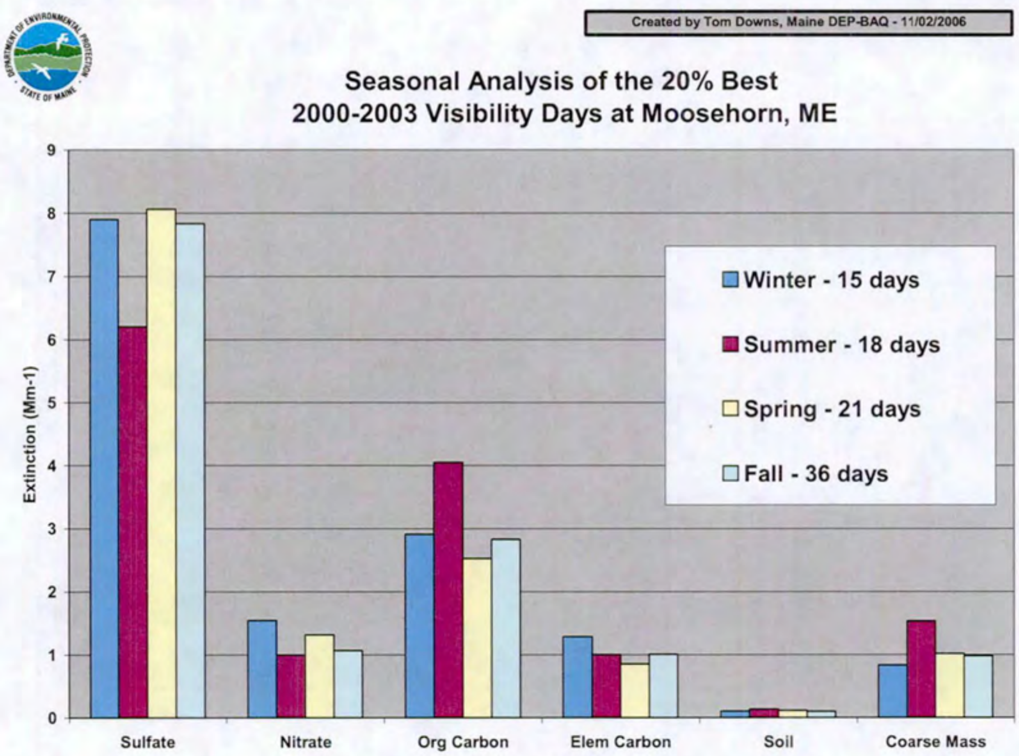
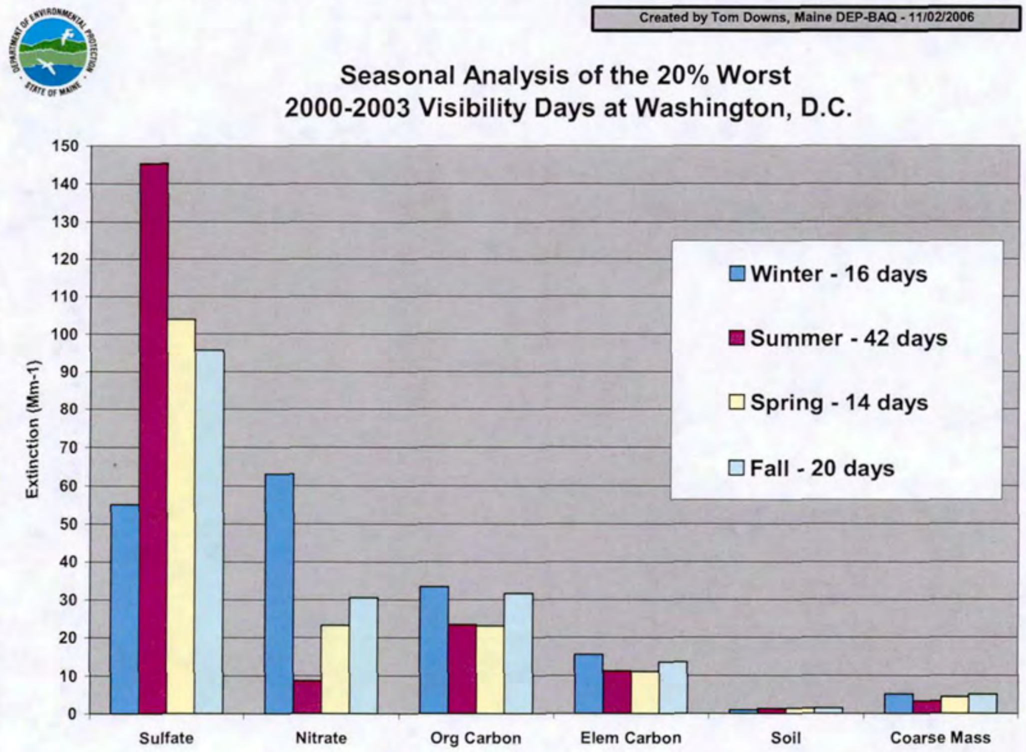


Figure B-12. 20% Worst and Best 2000-2003 Visibility Days at Washington, D.C.



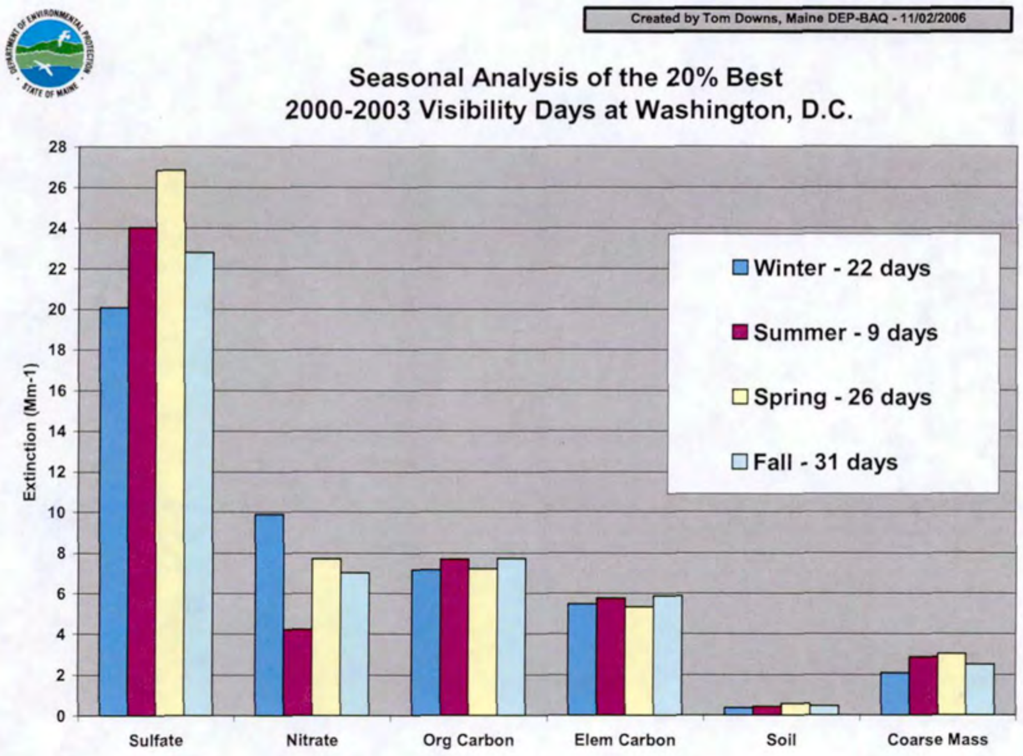
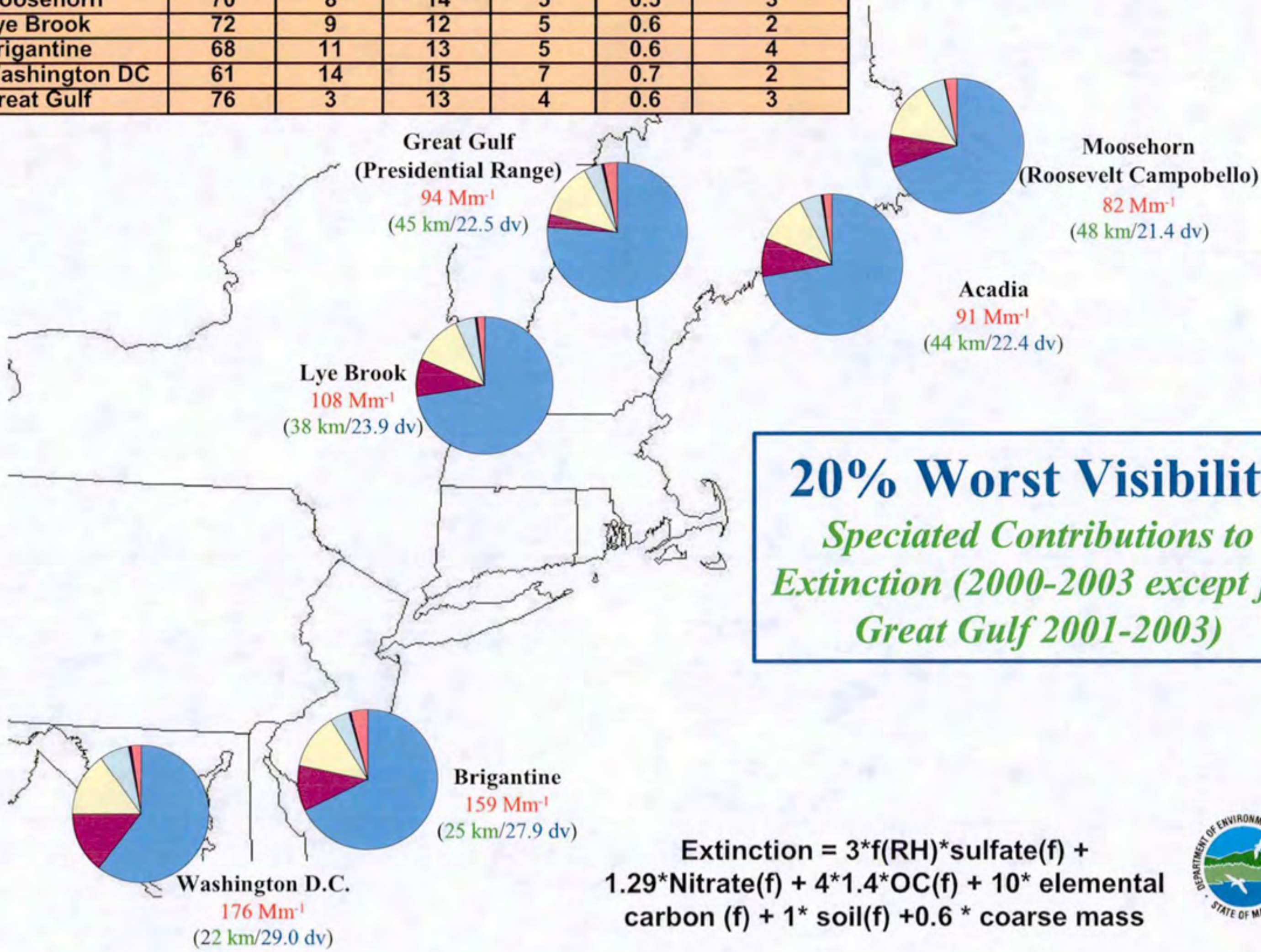


Figure B-13. 20% Best 2000-2003 Visibility Days Speciated Contributions to Extinction

Site	percent contributon to particle extinction					
	Sulfate	Nitrate	Org C	Elem C	Soil	Coarse Mass
Acadia	72	9	11	5	0.6	2
Moosehorn	70	8	14	5	0.5	3
Lye Brook	72	9	12	5	0.6	2
Brigantine	68	11	13	5	0.6	4
Washington DC	61	14	15	7	0.7	2
Great Gulf	76	3	13	4	0.6	3

Created by Tom Downs,
Maine DEP-BAQ 12/13/2005



20% Worst Visibility

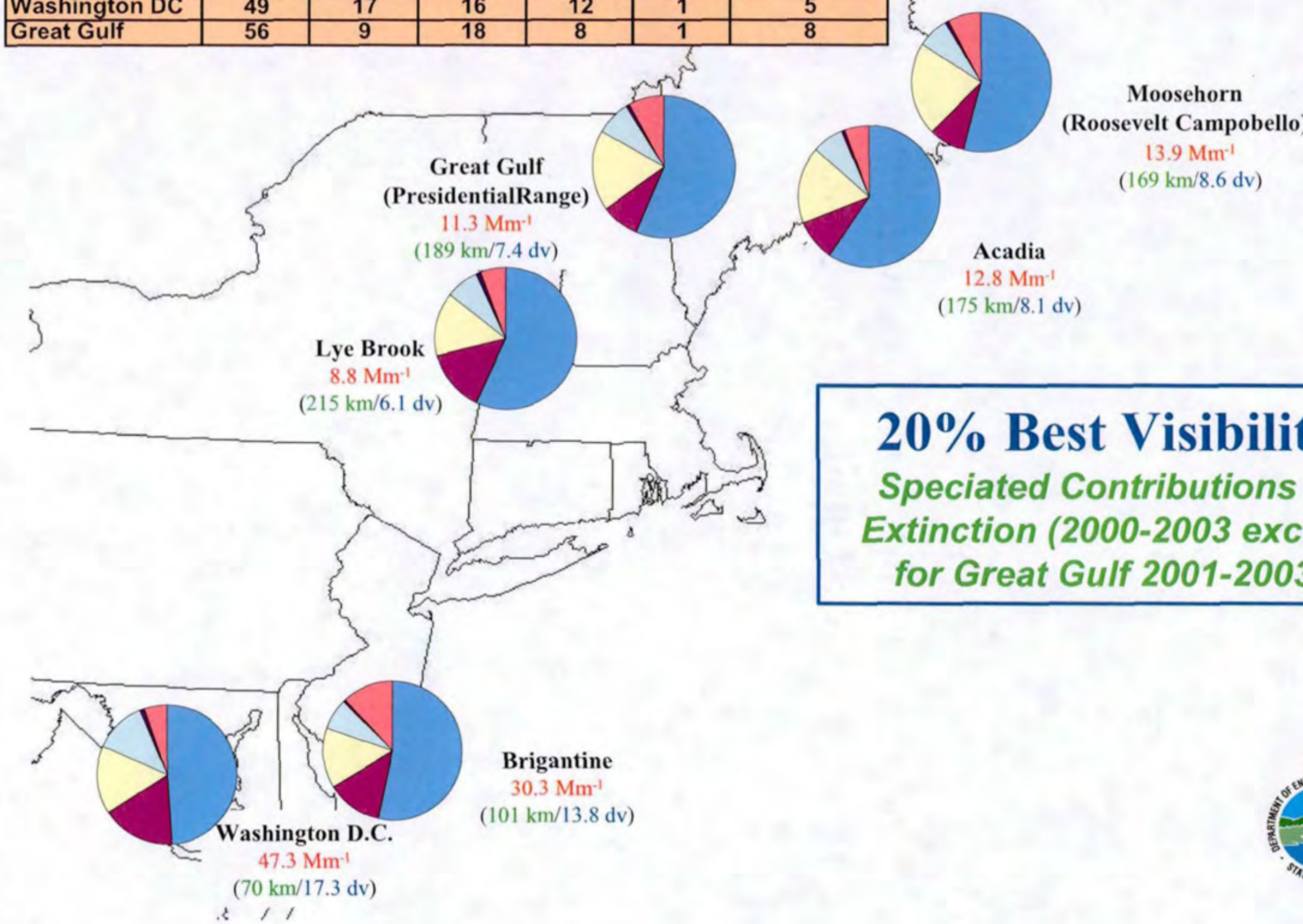
Speciated Contributions to Extinction (2000-2003 except for Great Gulf 2001-2003)

Extinction = 3*f(RH)*sulfate(f) + 1.29*Nitrate(f) + 4*1.4*OC(f) + 10* elemental carbon (f) + 1* soil(f) +0.6 * coarse mass

Figure B-14. 20% Best 2000-2003 Visibility Days Speciated Contributions to Extinction

	percent contributon to particle extinction					
Site	Sulfate	Nitrate	Org C	Elem C	Soil	Coarse Mass
Acadia	60	9	18	7	1	6
Moosehorn	54	9	22	7	1	8
Lye Brook	57	14	14	7	1	6
Brigantine	53	13	14	7	1	12
Washington DC	49	17	16	12	1	5
Great Gulf	56	9	18	8	1	8

Created by Tom Downs, Maine DEP-BAQ 12/13/2005



20% Best Visibility

Speciated Contributions to Extinction (2000-2003 except for Great Gulf 2001-2003)

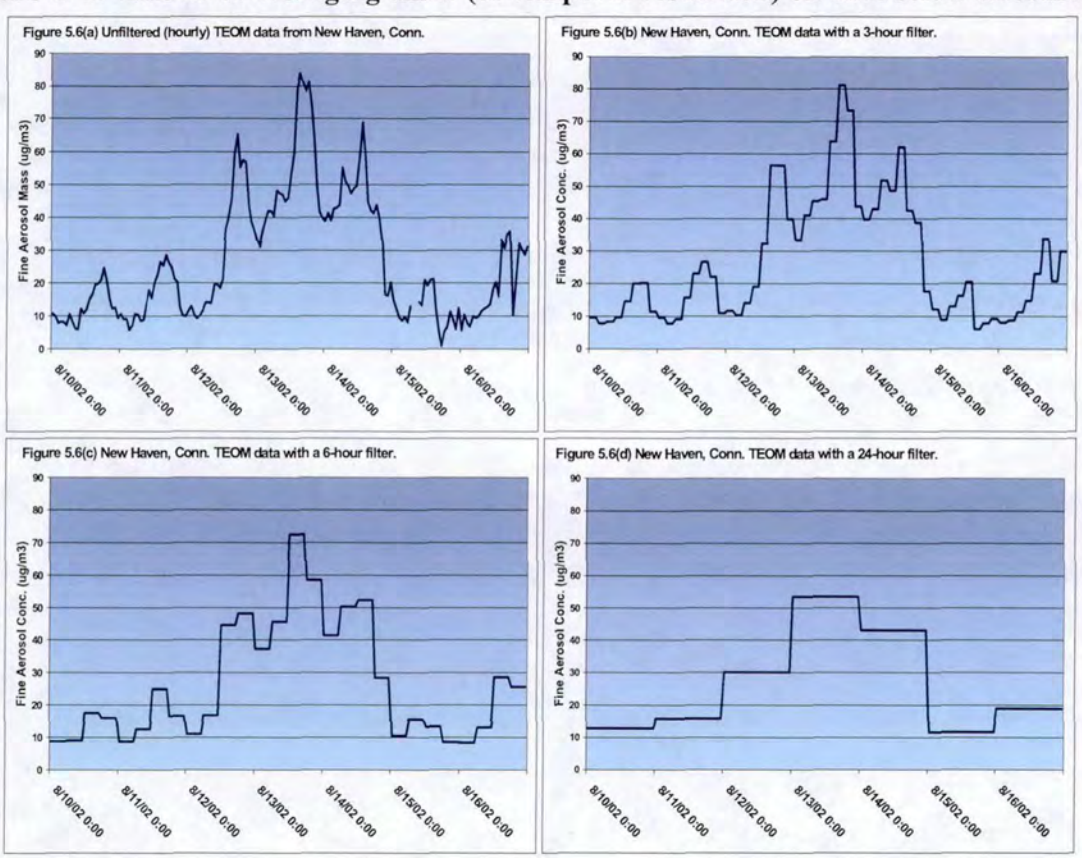
Appendix C: Additional Considerations for $PM_{2.5}$ Air Quality Management

APPENDIX C: ADDITIONAL CONSIDERATIONS FOR PM$_{2.5}$ AIR QUALITY MANAGEMENT

C.1. Averaging times and data interpretation

In analyzing the chemical data available for interpreting the air quality event of August 2002, it is important to point out that the use of different averaging times can have a profound effect on our understanding of the progression of any specific episode. Many subtleties of synoptic-scale meteorology and atmospheric chemistry are "aliased out" of data sets with temporal resolution greater than 3-6 hours. These effects are demonstrated in Figure C-1 which show fine aerosol TEOM data from New Haven for the "episode" period August 10-16, 2002. In these figures, the hourly TEOM values have been aggregated into 3-, 6- and 24-hour mean values. Average concentrations are inversely proportional to the length of the averaging period and the ratio of peak hourly concentration within a daily average ranges from about 1.5 to 1.75 for this episode.

Figure C-1. Effects of averaging times (or temporal resolution) on time series information



C.2. Rural versus urban $PM_{2.5}$ mass

Comparison of $PM_{2.5}$ concentrations from rural areas with those from urban/suburban areas can add significantly to our understanding of the impact on air quality of both urban sources and of medium to long-range fine aerosol transport. To assist with this approach, data from 10 pairs of rural and urban/suburban FRM sites throughout the MANE-VU region were selected and analyzed.

Table C-1 shows basic site description information including the approximate, straight-line distance between the site pairs.

Due to the difficulty in finding a significant number of urban-rural site pairs that operated on the same sampling schedule, sites with a mixture of schedules were used to insure samples representative of the entire MANE-VU region. As a result, three of the 20 sites employed an everyday schedule while two sites sampled every sixth day (the remainder sampled every third day). Data from the three everyday sites were edited so as to include data from the 1-in-3 schedule only. In all, a total of 1098 data points were possible from the 10 site pairs for 2002. Of the 1098 possible point-pairs, 951 (87%) were valid and were used in this analysis.

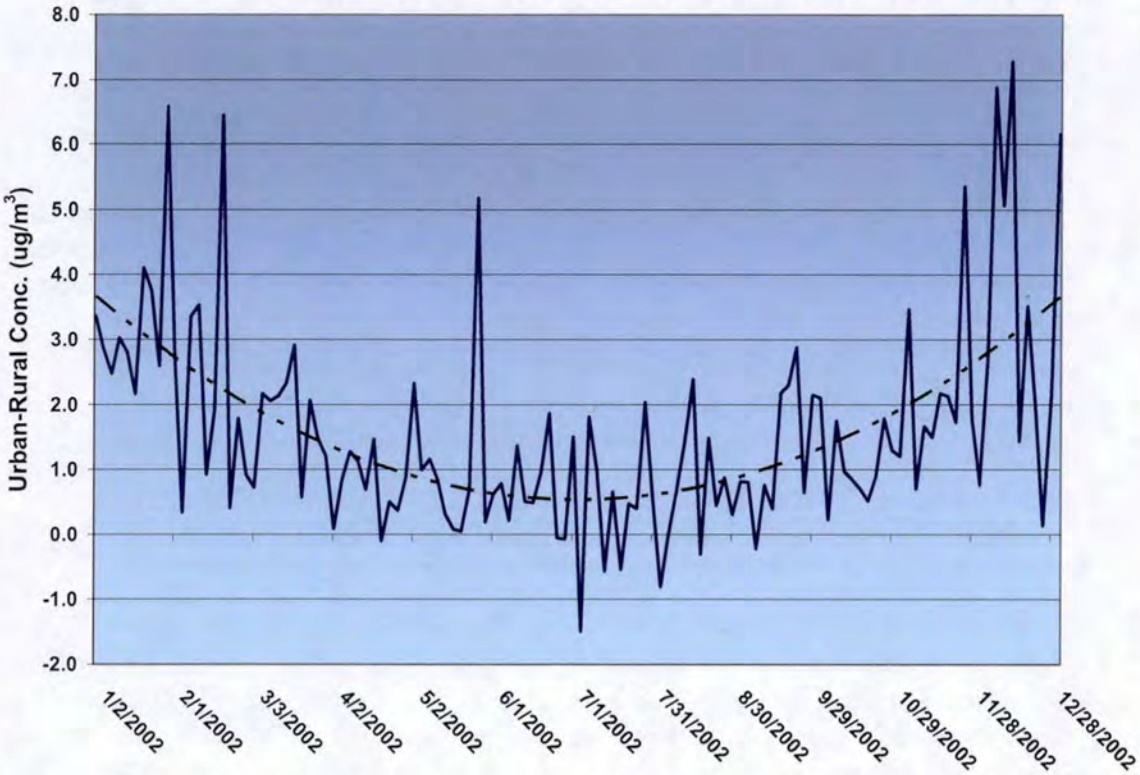
Table C-1. MANE-VU urban-rural site pair information

State	Site No	City	Land use	Location type	Longitude	Latitude	Inter-site Distance (mi)
DE	100051002		Agricultural	Rural	-75.55560	38.98470	
DE	100010002	Seaford	Residential	Suburban	-75.61310	38.64440	24.0
MA	250154002	Ware	Forest	Rural	-72.33472	42.29833	
MA	250130016	Springfield	Commercial	Urban & Center City	-72.59140	42.10890	17.6
MD	240030014		Agricultural	Rural	-76.65310	38.90250	
MD	245100049	Baltimore	Residential	Urban & Center City	-76.63750	39.26170	25.2
ME	230052003	Cape Elizabeth	Residential	Rural	-70.20778	43.56083	
ME	230010011	Lewiston	Commercial	Urban & Center City	-70.21500	44.08940	37.0
NJ	340218001		Agricultural	Rural	-74.85470	40.31500	
NJ	340210008	Trenton	Residential	Urban & Center City	-74.76360	40.22220	7.7
NY	360010012	Albany	Agricultural	Rural	-73.75690	42.68070	
NY	360930003	Schenectady	Residential	Suburban	-73.94020	42.79960	11.7
NY	361030001	Babylon	Commercial	Rural	-73.42030	40.74580	
NY	360590013	Bethpage	Residential	Suburban	-73.49060	40.76080	3.3
NY	360130011	Westfield	Agricultural	Rural	-79.60250	42.29080	
PA	420490003	Erie	Commercial	Suburban	-80.03860	42.14180	22.2
PA	420030093		Residential	Rural	-80.02080	40.60720	
PA	420030021	Pittsburgh	Residential	Suburban	-79.94140	40.41360	14.0
PA	420290100		Commercial	Rural	-75.76860	39.83440	
DE	100031012	Newark	Residential	Suburban	-75.76170	39.69190	10.0

As expected, urban/suburban areas, with their rich supply of emission sources, almost always reported higher concentrations than their nearby sister sites in rural areas. Of the 951 valid data pairs, 660 showed higher urban/suburban levels while 291 cases showed higher rural levels.

One interesting aspect of the 2002 urban-rural data concerns the pattern in seasonal differences between such site pairs. Figure C-2 shows the difference (urban-rural) between the 10 site pairs as a time series.

Figure C-2. Difference in FRM data between 10 urban-rural site pairs for 2002



Although some rural-to-urban seasonal differences are to be expected, the variation in the magnitude of this difference is surprising. In the warm/hot months, the mean rural/urban difference amounts to no more than ~0.7 $\mu g/m^3$ (based on a best-fit 2[nd] order polynomial curve), which is a relatively small differential. However, during the cool/cold months that difference climbs to almost 4 $\mu g/m^3$, demonstrating a total annual seasonal variation of at least 3 $\mu g/m^3$. Because the mean annual concentration of all sites is 12.6 $\mu g/m^3$, an annual variation of 3 $\mu g/m^3$ becomes significant.

One explanation for the observed seasonal variation concerns the temporal distribution of local and transported emissions. In the summertime, MANE-VU sites repeatedly experience sulfate events due to transport from regions to the south and west. During such events, rural and urban sites throughout MANE-VU record high (i.e., >15 $\mu g/m^3$) daily average $PM_{2.5}$ concentrations. During summer stagnation events, atmospheric ventilation is poor and local emissions are added to the transported burden with the result that concentrations throughout the region (rural and urban) are relatively uniform. There are enough of these events to drive the urban-rural difference down to less than 1 $\mu g/m^3$ during warm/hot months.

During the wintertime, strong local inversions frequently trap local emissions during the overnight and early morning periods, resulting in elevated urban concentrations. Rural areas experience those same inversions but have relatively fewer local sources so that wintertime concentrations in rural locations tend to be lower than those in nearby urban areas. Medium and long-range fine aerosol transport events do occur during the winter but at a much reduced rate compared to summertime. So, it is the interplay between local and distant sources as well as meteorological conditions that drive the observed seasonal urban-rural difference in FRM concentrations.

C.3. Seasonal relationship between $PM_{2.5}$ and NO_X

Because nitrogen oxides (NO_X) can be a good indicator of regional as well as local emissions, NO_X data for the MANE-VU region was downloaded from USEPA's AQS. Ultimately, data from six widely separated MANE-VU NO_X sites were selected (one site each in CT, DC, MA, NH, PA and VT). Sites were selected both for high data capture rates and geographic location. The NO_X data were then aggregated into regional averages on a daily basis and compared to $PM_{2.5}$ FRM data from 34 "everyday" sampling sites (which were also averaged on a regional basis).

During 2002, there were virtually no periods when regional mean $PM_{2.5}$ concentrations rose above 20 $\mu g/m^3$ and were not accompanied by rising (or already high) NO_X concentrations. However, as seen in Figure C-3, NO_X concentrations vary widely on an annual basis and tend to occur out-of-sync with fine particle concentrations.

Although the min/max extremes of these two pollutants are offset in time, they are highly correlated during some parts of the year. For example, Figure C-4 shows the regional $PM_{2.5}$ and NO_X data for the coldest (Jan., Feb., Nov., and Dec.) and hottest (May, June, July and Aug.) seasons of 2002. Wintertime NO_X and $PM_{2.5}$ concentrations are rather well correlated (r^2=0.67) while summertime concentrations are not at all linked. This dichotomy can be explained by several coincident effects including: 1) reduced UV radiation during cold months (which prevents photolysis of NO_2 to O_3); 2) the increase in space heating requirements from stationary sources (which preferentially increases morning NO_X emissions; increased NO_X emissions due to "cold-start" mobile source engines and 3) decreased mixing height depths due to reduced solar input (which allows morning concentrations to build quickly). Note that the Spring/Fall $PM_{2.5}$ vs. NO_X correlation (not shown) lies about mid-way between the winter/summer values shown in Figure C-4.

Figure C-3. Regional $PM_{2.5}$ and NO_X in 2002

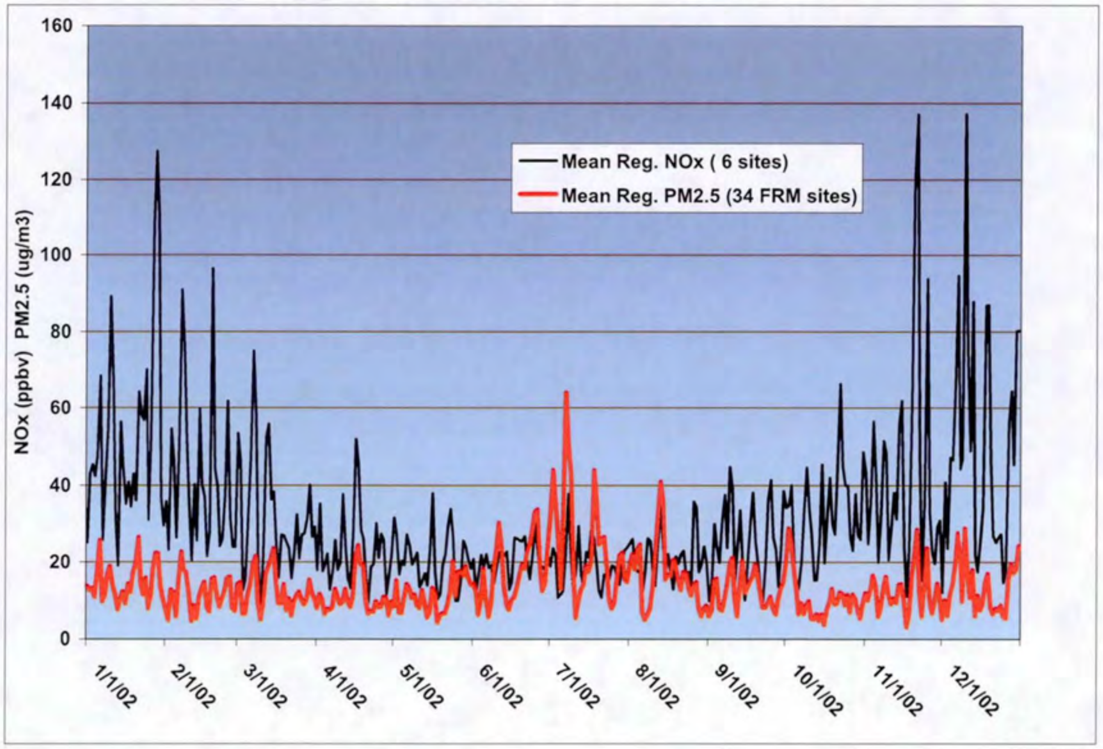
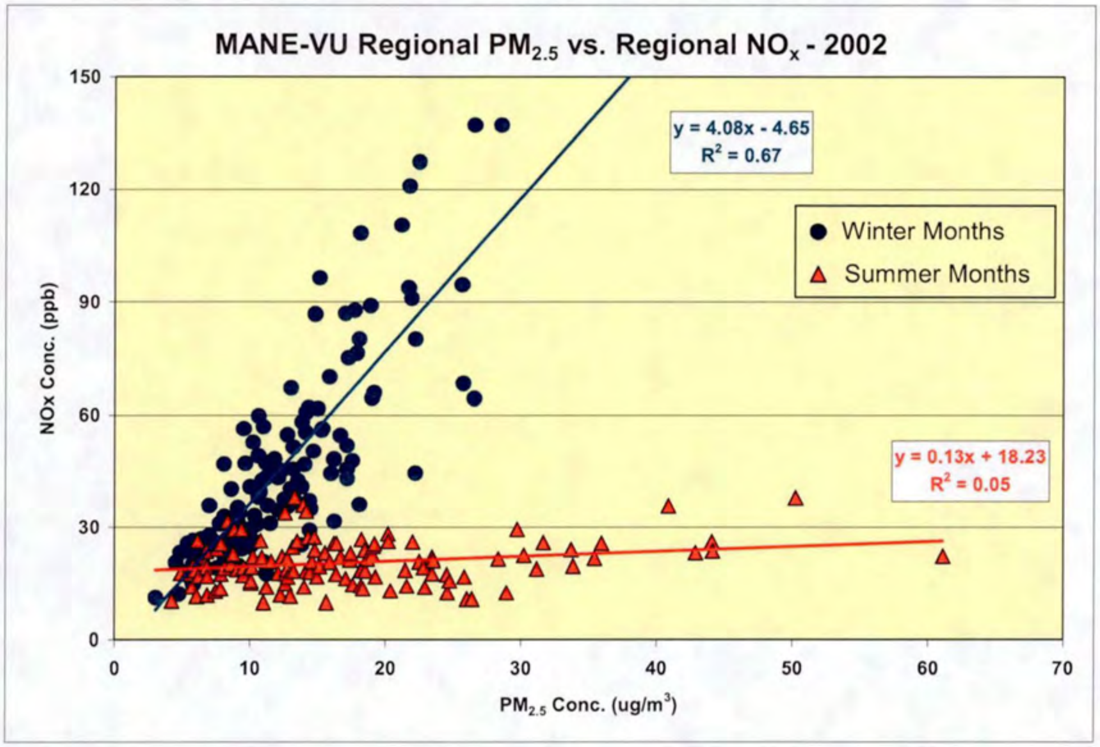


Figure C-4. $PM_{2.5}$ vs. NO_X correlation by season



ATTACHMENT DD

Technical Support Document on Measures to Mitigate the Visibility Impacts of Construction Activities in the MANE-VU Region

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Technical Support Document on Measures to Mitigate the Visibility Impacts of *Construction Activities in the MANE-VU Region*
Draft: September 1, 2006

1. Introduction

Each state must develop a long-term (10-15 years) strategy for making reasonable progress towards the national goal stated in 40 CFR section 51.300(a), "preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution." States are required to develop long-term strategies for each mandatory Class I Federal area located within the state and each mandatory Class I Federal area located outside the state that may be affected by sources within the state. According to 40CFR section 51.308(d)(3)(v)(B), states must consider "measures to mitigate the impacts of construction activities" in developing its long-term strategies for regional haze.

The purpose of this technical support document is to assist States in considering measures in the MANE-VU Region to mitigate the impacts of construction activities. This document provides background information on the air quality impacts of construction activities, presents relevant emissions inventory and contribution assessment results, describes potential control measures, and summarizes state regulations currently in place in the MANE-VU Region.

2. Air Quality Impacts of Dust and Diesel Usage from Construction Activities

According to the EPA (www.epa.gov/ttn/chief/ap42/ch13), construction activities may have a significant, albeit temporary, impact on local air quality. Construction activities are sources of fugitive dust and air pollutants from the use of diesel powered equipment.

There are two primary mechanisms of generating fugitive dust, pulverization of surface materials by mechanical equipment and entrainment of dust by wind. Large dust particles typically settle out near the source, creating potential nuisance issues. Particles larger than 100μm generally settle out within six to nine meters from the source while particles between 20 and 100μm typically fall out within a few hundred feet of the source. Smaller particles, especially particles smaller than 10μm (PM_{10}) can persist in the atmosphere, possibly contributing to diminished visibility.

Construction activities that can contribute substantial dust emissions include land clearing, drilling and blasting, ground excavation, hauling dirt, and the construction of roads and buildings. Equipment traffic over temporary roads at construction sites can make up a large portion of the emissions. The use of diesel fuel in construction equipment causes the emission of Carbon Monoxide (CO), Volatile Organic Compounds (VOCs), Nitrogen Oxides (NOx), and Particulate Matter (PM) into the air. These pollutants may contribute to reduced visibility. Construction activities that contribute to the release of the above mentioned pollutants include, idling, the use of high sulfur fuel and diesel, the lack of exhaust controls, and the use older vehicles that are not properly maintained.

In contrast to other fugitive dust sources, such as dust generated from unpaved roads and agricultural tilling practices, construction activities are temporary with a definable beginning and end, and vary significantly over different phases of the construction project. Dust and diesel emissions from construction sites vary daily depending on the level of activity, specific operations, specific machinery used, and meteorological conditions. Other factors that play a role in dust emissions include the silt (particles smaller than 75μm in diameter) content of the soil, soil moisture, the speed and weight of construction equipment. Dust emissions are positively correlated with silt content and the weight of vehicles and negatively correlated with soil moisture content.

3. Relevant Emissions Inventory Results

The Mid-Atlantic Regional Air Management Association (MARAMA), on behalf of MANE-VU, developed a "Fugitive Dust Construction Area Source Category Calculation Methodology Sheet," for use by MANE-VU States. The calculation methodology sheet describes how States may calculate emissions of particulate matter from residential, non-residential, and road construction activities. The calculation methodology sheet, which was most recently updated in December 2004, is available online at http://www.marama.org/visibility/Calculation_Sheets/FugitiveDustConstruction122004.doc.

States submitted $PM_{2.5}$ and PM_{10} data on emissions from construction activities of various types, which were compiled in the MANE-VU 2002 Inventory. Under contract by MARAMA, E.H. Pechan and Associates summed the $PM_{2.5}$ and PM_{10} data for the categories of residential construction, road construction, and industrial/commercial/institutional construction. These category values were added together to determine the Total Construction Emissions for each state, shown in Tables 1 and 2 and Total Off-Highway Diesel Emissions for each state shown in Tables 3 and 4. Each table below shows the Total Emissions of $PM_{2.5}$ and PM_{10} from all sources of pollution, including point source, area, non-road, and on-road in units of tons per year. In the case of non-diesel construction activities, the percentages of construction emissions from area sources and the percentage of construction emissions from all sources were calculated and shown in Tables 1 and 2 for $PM_{2.5}$ and PM_{10} respectively. In the case of diesel emissions the total emissions from all sources are followed by the Total Nonroad Source Emissions, and then the Total Off-Highway Diesel Emissions, the Construction Emissions as a percent of Nonroad Inventory and finally the Construction Emissions as a percent of Total Inventory were calculated and shown in Tables 3 and 4 for $PM_{2.5}$ and PM_{10} respectively.

Table 1: 2002 $PM_{2.5}$ emissions from construction activities (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from all sources of $PM_{2.5}$ (tons/year)	Total Area Source Emissions $PM_{2.5}$ (tons/year)[1]	Total Construction Emissions $PM_{2.5}$ (tons/year)	Construction Emissions as a % of Area Sources Emissions	Construction Emissions as a % of Total Inventory
Connecticut	18365.9	14247.3	932.7	6.5	5.1
Delaware	8210.2	3203.6	268.6	8.4	3.3
District of Columbia	1388.8	804.8	156.9	19.5	11.3
Maine	40824.9	32773.7	373.4	1.1	0.9
Maryland	38929.7	27318.3	2835.1	10.4	7.3
Massachusetts	51864.4	42067.5	2530.8	6.0	4.9
New Hampshire	21996.8	17532.0	352.9	2.0	1.6
New Jersey	31595.3	19349.6	88.3	0.5	0.3
New York	108952.6	87154.2	7039.8	8.1	6.5
Pennsylvania	108811.6	74924.7	7694.7	10.3	7.1
Rhode Island	2901.3	2064.2	301.8	14.6	10.4
Vermont	12300.3	11064.5	264.5	2.4	2.2
MANE-VU	446142.0	332504.5	22839.4	7.5	5.1

[1] SCC 23110xxxx

Table 2: 2002 PM_{10} emissions from construction activities (Data Source: 2002 MANE-VU Modeling Inventory, version 3.0)

State	Total Emissions from all sources of PM_{10} (tons/year)	Total Area Source Emissions PM_{10} (tons/year)[1]	Total Construction Emissions PM_{10} (tons/year)	Construction Emissions as a % of Area Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	53430.1	48280.7	9327.4	19.3	17.5
Delaware	18857.7	13038.6	2712.1	20.8	14.4
District of Columbia	3962.6	3269.2	784.3	24.0	19.8
Maine	178918.5	168953.4	3733.8	2.2	2.1
Maryland	112193.1	95060.2	28350.7	29.8	25.3
Massachusetts	205629.6	192838.7	25306.1	13.1	12.3
New Hampshire	48531.8	43328.1	3529.2	8.1	7.3
New Jersey	76893.3	61600.9	882.8	1.4	1.1
New York	398048.9	369594.6	70397.9	19.0	17.7
Pennsylvania	449572.9	391896.9	76946.6	19.6	17.1
Rhode Island	9439.7	8294.6	3018.0	36.4	32.0
Vermont	57633.7	56130.6	2645.1	4.7	4.6
MANE-VU	1613112.0	1452286.6	227634.0	16.6	14.3

[1] SCC 23110xxxx

Table 3: 2002 $PM_{2.5}$ emissions from diesel emissions (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from All Sources $PM_{2.5}$ (tons/year)	Total Nonroad Source Emissions $PM_{2.5}$ (tons/year)	Total Off-Highway Diesel Emissions $PM_{2.5}$ (tons/year)[1]	Construction Emissions as a % of Nonroad Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	18365.9	1793.9	582.5	32.5	3.2
Delaware	8210.2	925.6	215.3	23.3	2.6
District of Columbia	1612.8	298.7	235.9	79.0	14.6
Maine	40824.9	1329.4	261.8	19.7	0.6
Maryland	38929.7	4357.1	1161.6	26.7	3.0
Massachusetts	51864.4	3226.4	1032.0	32.0	2.0
New Hampshire	21996.8	965.4	268.0	27.8	1.2
New Jersey	31595.3	4997.2	1437.4	28.8	4.5
New York	108952.6	8820.9	2556.2	29.0	2.3
Pennsylvania	108811.6	8440.1	1862.7	22.1	1.7
Rhode Island	2901.3	443.1	128.7	29.0	4.4
Vermont	12300.3	485.8	109	22.4	0.9
MANE-VU	446365.9	36083.6	9851.2	27.3	2.2
[1] SCC 2270002xxx					

Table 4: 2002 PM_{10} emissions form diesel emissions (Data Source: 2002 MANE-VU Modeling Inventory, Version 3.0)

State	Total Emissions from All Sources PM_{10} (tons/year)	Total Nonroad Source Emissions PM_{10} (tons/year)	Total Off-Highway Diesel Emissions PM_{10} (tons/year)[1]	Construction Emissions as a % of Nonroad Source Emissions	Construction Emissions as a % of Total Inventory
Connecticut	53430.1	1952.1	633.2	32.4	1.2
Delaware	18857.7	1021.4	234.0	22.9	1.2
District of Columbia	6986.7	310.2	243.2	78.4	3.5
Maine	178918.5	1436.8	269.9	18.8	0.2
Maryland	112193.1	4936.0	1262.7	25.6	1.1
Massachusetts	205629.6	3531.2	1121.7	31.8	0.5
New Hampshire	48531.8	1057.8	291.3	27.5	0.6
New Jersey	76893.3	5495.1	1562.3	28.4	2.0
New York	398048.9	9605.3	2778.5	28.9	0.7
Pennsylvania	449572.9	9737.9	2024.7	20.8	0.5
Rhode Island	9439.7	500.2	139.9	28.0	1.5
Vermont	57633.7	529.9	118.5	22.4	0.2
MANE-VU	1616136.2	40113.9	10679.9	26.6	0.7
[1] SCC 2270002xxx					

Data on area source emissions and the total emissions for $PM_{2.5}$ and PM_{10} are also shown in Tables 1 and 2. Both tables show that construction dust is a major contributor to total emissions of $PM_{2.5}$ and especially PM_{10} with 5.1% and 14.3% emission contribution respectively. The MANE-VU states with the largest contribution to $PM_{2.5}$ emissions are the District of Columbia, Rhode Island, Maryland, and Pennsylvania. The MANE-VU states with the largest contribution to PM_{10} emissions are the Rhode Island, Maryland, and the District of Columbia.

Data on off-highway and nonroad diesel emissions sources for $PM_{2.5}$ and $_{10}$ are also shown in Tables 3 and 4. These tables show that diesel emissions do not contribute significantly to $PM_{2.5}$ and PM_{10} emissions with 2.2% and 0.7% respectively. However, they do make a contribution to PM emissions. According to Table 3, the District of Columbia, New Jersey, and Pennsylvania contribute the most to $PM_{2.5}$ diesel emissions of all the MANE-VU states. The District of Columbia, New Jersey, and Rhode Island contribute the most to PM_{10} diesel emissions in MANE-VU states as seen in Table 4. Construction emissions are a large percentage of the total PM inventory in urban areas, for example in the District of Columbia has the highest percentage of construction emissions as a percentage of nonroad source emissions and the total inventory.

It should be noted that "a fugitive dust transport fraction" is applied to emissions numbers for construction activities to account for dust settling out of the air close to the sources. This application essentially reduces fugitive dust emissions to approximately one-fourth of the emissions values before they are used in photochemical transport models. As a result of this application, photochemical models produce more consistent results with ambient air quality monitoring data. In addition, the EPA has recently recommended that a new emissions factor be used in determining fugitive dust emissions from construction activities. MANE-VU States have agreed to use the new emissions factor, and, as a result, the values for $PM_{2.5}$ and PM_{10} emissions from construction activities are significantly lower in Version 3.0 of the 2002 MANE-VU Modeling Inventory, compared to Version 2.0 of the 2002 MANE-VU Modeling Inventory.

4. Ambient Air Quality Monitoring Data

The Northeast States for Coordinated Air Use Management (NESCAUM), on behalf of MANE-VU, analyzed ambient air quality data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network in several areas within and near Class I Areas in the Northeast and Mid-Atlantic Region. Figure 1 shows the relative contributions of sulfate, nitrate, organic carbon, crustal material, elemental carbon, and Rayleigh scattering to visibility impairment on the 20% clearest and 20% haziest days in 1999. Construction activities contribute only a fraction to the crustal material emissions that were measured and diesel emissions from construction sites contribute to elemental carbon, nitrate, and organic carbon.

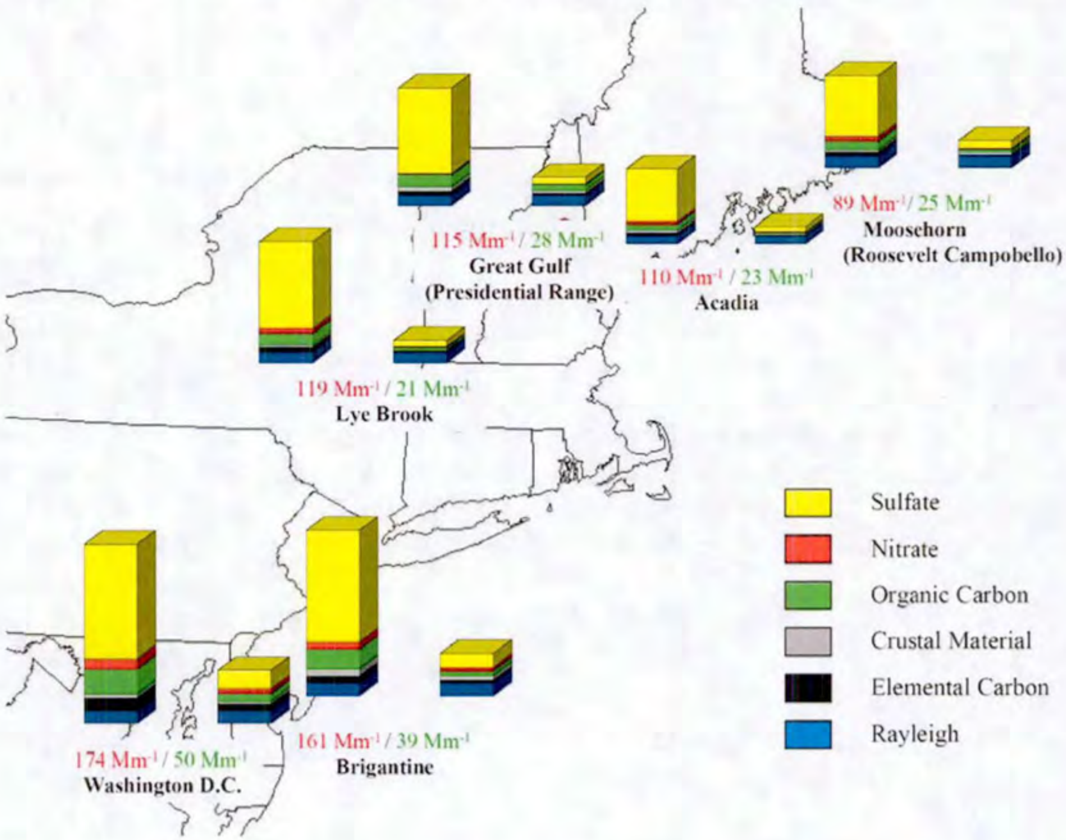


Figure 1: Speciated contribution to total atmospheric light extinction in or near Class I Areas in the Northeast and Mid-Atlantic states on 20 percent of days with the worst (left bar) and best (right bar) visibility conditions during 1999. (Source: Technical Memorandum #1: Updated Statistics for the MANE-VU Region, prepared by the Northeast States for Coordinated Air Use Management, on behalf of MANE-VU in February 2002. The memorandum is available online at http://bronze.nescaum.org/regionalhaze/memoranda/Memo1-VisData.pdf.)

On the 20% haziest days in 1999, sulfate was the greatest contributor to visibility impairment at all of the sites analyzed, and sulfate and Rayleigh scattering were the largest contributors on the 20% clearest days in 1999. Crustal material, including dust from construction activities and other sources of dust, was only a minor contributor to haze on the 20% clearest and haziest days in 1999.

Data from the IMPROVE monitoring network has also been analyzed to estimate the contribution of soil dust to $PM_{2.5}$ concentrations across the nation. Figure 2 shows the results of an analysis on 2001 IMPROVE data.

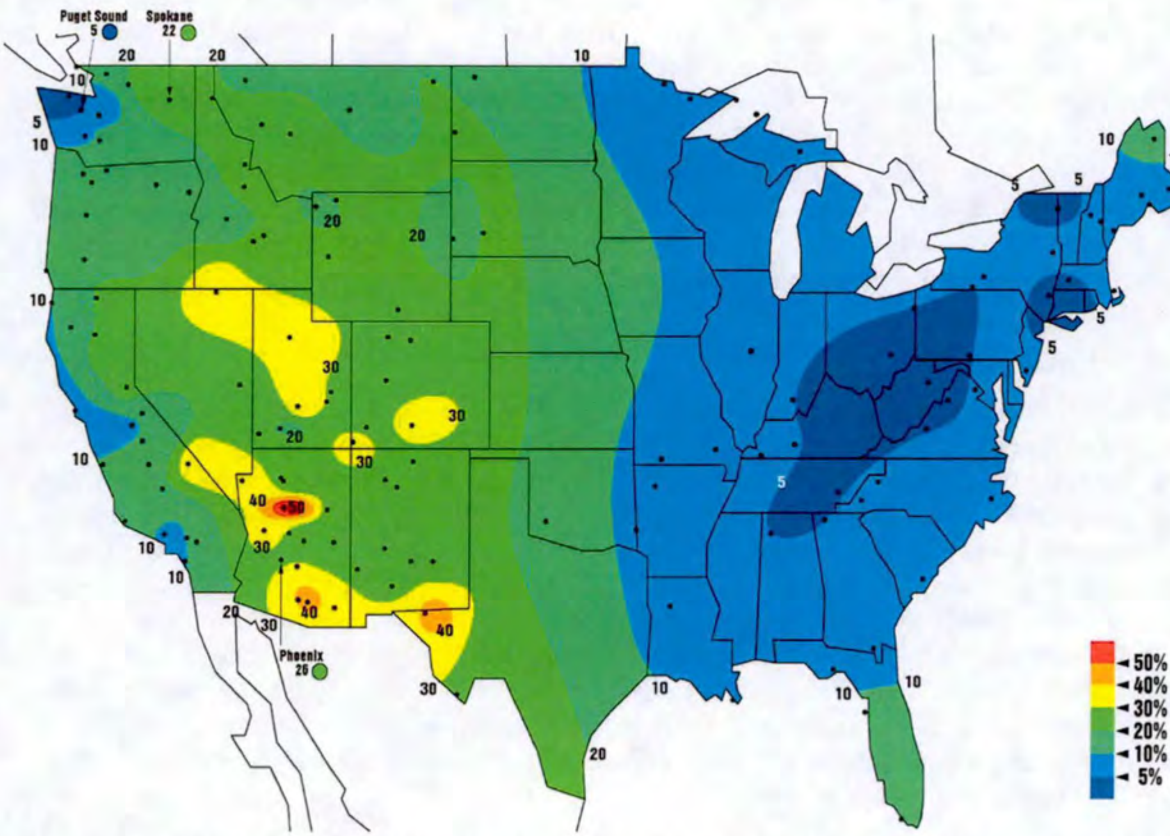


Figure 2: Annual Soil Fraction of Fine Particle Mass (2001). (Source: "Spatial and Seasonal Patterns in Speciated Fine Particle Concentration in the Rural United States," a presentation by Bret Schichtel of the National Park Service and William Malm, Marc Pitchford, Lowell Ashbaugh, Robert Eldred, and Rodger Ames, made available online by IMPROVE at http://vista.cira.colostate.edu/improve/Publications/GrayLit/gray_literature.htm.)

According to IMPROVE results, whereas soil dust contributes more than 50% of the $PM_{2.5}$ mass in parts of the western United States, dust contributes less than 10% in the Mid-Atlantic and Northeast Regions of the United States. Construction activities are not the only sources of construction dust in the Region. Other sources of fugitive dust, such as dust from paved and unpaved roads and agricultural tilling practices, are also significant sources. Since construction dust only partially comprises the total dust component and since soil dust is not a large contributor to ambient $PM_{2.5}$ concentrations, dust from construction activities is unlikely a large component of $PM_{2.5}$ concentrations measured in MANE-VU Class I Areas. These results confirm the NESCAUM findings that dust is not a major contributor to haze in the Region.

5. Potential Available Control Measures

There are several control options for reducing dust and diesel emissions from construction activities. The most common methods for controlling dust emissions include watering surface materials and minimizing surface wind speed using windbreaks or source enclosures. Chemicals can also be used to stabilize surface materials, but these methods can be expensive and/or have adverse ecological effects. Dust minimization techniques used when hauling dirt include covering trucks and rapidly cleaning up spillage. Early paving of permanent roads can also help control dust during certain construction activities. In the case of reducing diesel emissions, four options have been utilized with success. The use of cleaner fuels (e.g., low sulfur, emulsified diesel), the installation of exhaust controls (e.g., diesel oxidation catalysts), placing limitations on the time and location of idling machines, and assuring that heavy duty vehicles comply with state regulations (e.g., smoke standards).

6. Existing Regulations

Most MANE-VU states and the District of Columbia have regulations in place to control dust emissions from construction activities that are relevant to regional haze and certain MANE-VU states have regulations in place to control diesel emissions. MARAMA requested information regarding state control measures, and received responses from every MANE-VU state and the District of Columbia. The following descriptions of state regulations incorporate the information provided by Connecticut (Michael Geigert and Merrily Gere), Delaware (Jack Sipple), the District of Columbia (Rama Tangirala), Maine (Jeff Crawford), Maryland (Brian Hug), Massachusetts (Ken Santlal and Eileen Hiney), New Hampshire (Andy Bodnarik), New Jersey (Ray Papalski), New York (John Kent), Pennsylvania (Nancy Herb), Rhode Island (Ted Burns), and Vermont (Paul Wishinski). The following descriptions are provided as background information and are not intended to incorporate any regulations, policies, programs or projects into the State Implementation Plan.

6.1 Connecticut

Section 22a-174-18 of the Regulations of Connecticut State Agencies, "Control of particulate matter and visible emissions," addresses the control of airborne particulate matter and fugitive particulate matter in subsections (c) and (d). These regulations, which include dust control measures and visible emissions from diesel powered mobile sources, apply to road building and construction activities. Regulations are available online at http://www.dep.state.ct.us/air2/regs/mainregs.htm.

Two additional emissions control programs related to construction activities are currently underway in Connecticut. First, the Connecticut Clean Air Construction Initiative is a 10-year pilot project designed to reduce idling and operational emissions from construction equipment used to complete the I-95 New Haven Harbor Crossing Improvement Project also called the Q Bridge Project. Retrofits and idling restrictions for this project are required as part of contract specifications with the Connecticut Department of Transportation (CTDOT). Diesel retrofits and idling restrictions for construction vehicles were also written into a special act called the Connecticut Clean Diesel Plan by the Connecticut Department of Environmental Protection (CTDEP). The CTDEP hopes to work with CTDOT to expand this program to all state road construction projects. Currently, 150 diesel powered construction machines have been retrofits with oxidation catalysts and by the projects completion 200 machines will be retrofitted.

Second, a PM_{10} limited maintenance plan for the City of New Haven was approved by EPA. The plan includes some contingency measures that apply to New Haven under a state order. The measures focus on street paving and sweeping.

The Connecticut Department of Transportation has implemented diesel vehicle emission controls that Contractors and Sub-contractors are obligated to follow. Any non-road construction equipment with engine horsepower (HP) rating of 60 HP and above that are assigned to a contract for a period in excess of 30 consecutive calendar days must be retrofitted with Emission Control Devices and/or use Clean Fuels in order to reduce diesel emissions. Contractors must submit a certified list of non-road diesel powered construction equipment what will be retrofitted with emission control devices and/or use Clean Fuel and include the addition or deletion of non-road diesel equipment. The list has three parts and a monthly report must also be submitted by the contractor updating the above stated information. If these rules are not followed the contractor will be issued a Non-Compliance and given 24 hours to bring the equipment into compliance or removed it from the project. If the contractor still does not comply further and more extreme actions will be taken. For further information on this project contact the Connecticut Department of Transportation, regarding the I-95 New Haven Harbor Crossing Corridor Improvement Program.

Connecticut has regulations in place to control fugitive emissions from construction. In Section 22a-174-18(c) of regulations from the Department of Environmental Protection state that, "No person shall cause or allow the emission of visible particulate matter beyond the legal boundary of the property on which such emission occurs that either diminishes the health, safety or enjoyment of people using a building or structure located beyond the property boundary…No person shall emit particulate matter into the ambient air in such a manner as to cause a nuisance." The regulations also place strict controls on the type and amount of visible particulate matter that can be released by the owner or operator of the equipment. These regulations are available online at: http://www.dep.state.ct.us/air2/regs/mainregs/sec18.pdf

6.2 Delaware

Delaware Air Quality Management (AQM) Regulation 6, "Particulate Emissions from Construction and Materials Handling," addresses control measures for particulate emissions from construction and materials handling operations to minimize air pollution. This regulation is available online at http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/reg_6.pdf.

Delaware has no regulations or laws to control emissions from diesel equipment at construction sites.

6.3 District of Columbia

Chapter 6 of the Title 20 D.C. Municipal Regulations (20 DCMR), addresses control measures for particulate matter. Section 605 of 20 DCMR "Control of Fugitive Dust" specifically addresses the fugitive dust control measures that apply to roads, parking lots, vehicles transporting dusty materials, loading & unloading and demolition of buildings activities. Additionally, Section 903 of the Title 20 DCMR addresses odorous or other nuisance air pollutants.

There are no regulations or laws in place to control emissions from diesel at construction sites in Washington D.C. However, there are restriction on the use of heavy duty diesel engines produced for the 2005 and 2006 model years and heavy duty vehicles containing these engines. These vehicles are not allowed to be registered in the District of Columbia without the applicant presenting documentation that the California Air Resources Board has issued an Executive Order for the vehicle or engine certifying that it complies with the applicable exhaust emission standards under the California Code of Regulations. The emission standards for these engines are referenced to CARB Title 13, section 1956.8 which are available online at http://www.calregs.com/linkedslice/default.asp?SP=CCR-1000&Action=Welcome.

6.4 Maine

The Department of Environmental Protection (DEP) Regulations Chapter 101, "Visible Emissions," establishes opacity limitations for emissions from several categories of air contaminant sources, including fugitive emissions. DEP Regs Chapter 101 can be applied to construction activities and is available online at http://www.maine.gov/sos/cec/rules/06/096/096c101.doc

Maine has no regulations or laws to control emissions from diesel equipment at construction sites.

6.5 Maryland

COMAR 26.11.06.03D addresses "Particulate Matter from Materials Handling and Construction." This regulation, available online at http://www.dsd.state.md.us/comar/26/26.11.06.03.htm, states that during construction activities there must be "reasonable precautions to prevent particulate matter from becoming airborne" and lists possible control measures.

Maryland has no regulations or laws to control emissions from diesel equipment at construction sites.

6.6 Massachusetts

Control measures to mitigate the emission of particulate matter from construction activities are included in the Massachusetts Department of Environmental Protection Air Pollution Patrol regulations. According to regulation 310 CMR 7.09, "No person having control of any dust or odor generating operations such as construction work shall permit emissions therefrom which cause or contribute to air pollution," and written notification to the Department is required ten working days prior to the initiation of construction.

According to regulation 310 CMR 7.06, "No person shall cause, suffer, allow, or permit excessive emission of visible air contaminants, other than water, from a diesel engine." In addition regulation 310 CMR 7.11 states that, "All motor vehicles registered in the Commonwealth shall comply with pertinent regulations of the Registry of Motor Vehicles relative to exhaust and sound emissions."

Regulation 310 CMR 7.06, 7.09 and 7.11 are available online at http://www.mass.gov/dep/air/laws/7b.htm#09

6.7 New Hampshire

Fugitive dust control measures for construction activities are included in CHAPTER Env-A 1000, "Prevention, Abatement, and Control of Open Source Air Pollution," PART Env-A 1002, "Fugitive Dust." Subsection Env-A 1002.04, "Precautions to Prevent, Abate, and Control Fugitive Dust," lists potential dust control measures and is available online at http://www.gencourt.state.nh.us/rules/env-a1000.html.

New Hampshire has no regulations or laws to control emissions from diesel equipment at construction sites.

6.8 New Jersey

Fugitive emissions are regulated under the New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 8 (NJAC 7:27-8 et seq.); Permits and Certificates, available on-line at http://www.state.nj.us/dep/aqm/rules.htm. Dust control measures for construction are not specifically mentioned. Any off-site impacts from construction activities are also prevented by NJAC 7-27-5 et seq. - Prohibition of Air Pollution that prevents any activity from being injurious to human health or welfare at any off-site location.

New Jersey has recently passed the Diesel Retrofit Law which is expected to reduce particulate emissions from some equipment that will be used in municipal construction or maintenance projects. The 2005 diesel retrofit law regulates publicly-owned off-road equipment in New Jersey by requiring retrofitting with exhaust particulate emissions control systems. The Department of Environmental Protection is charged with designating Best Available Retrofit Technology and defining specific types of equipment to be retrofitted. The law limits the choices of BART to those verified under the EPA and CARB diesel emissions control strategy verification programs. A constitutionally dedicated portion of the State Corporate Business Tax serves as the funding source to reimburse the retrofit costs.

6.9 New York

The New York State Department of Environmental Conservation Rules and Regulations Part 211, "General Prohibitions" includes a clause that places limits on particulate emissions, 211.3, "Visible emissions limited." The regulation is available online at http://www.dec.state.ny.us/website/regs/part211.html

In addition, the New York State Department of Transportation (NYSDOT) Environmental Procedures Manual Chapter 1.1 Section 15, "Construction Related Air Quality Impacts," addresses air quality issues associated with construction activities and includes possible control measures. This manual is available online at http://www.dot.state.ny.us/eab/epm.html.

New York has no regulations or laws to control emissions from diesel equipment at construction sites.

6.10 Pennsylvania

25 PA Code, Chapter 123, Sections 123.1, "Prohibition of certain fugitive emissions," and 123.2, "Fugitive particulate matter," regulate emissions from construction and other related activities. These regulations were adopted on September 10, 1971 and have been "SIP approved." These regulations are available online at
http://www.pacode.com/secure/data/025/chapter123/s123.1.html and
http://www.pacode.com/secure/data/025/chapter123/s123.2.html.

Pennsylvania does not have regulations to control emissions from diesel equipment at construction sites. However, permits are required for the operation of diesel and nonroad engines. Section 2 of the both the General Plan Approval And/Or General Operating Permit (BAQ-GPA/GP 9) and the General Plan Approval And/Or General Operating Permit (BAQ-GPA/GP 11), states that nonroad and diesel engines must have the best available technology (BAT) installed and in operation and compliance so that the diesel engine is in compliance with regulated emissions standards. Both General Permits (GPs) require the permittee to maintain accurate records of the amount of time the engine is in operation per month, including the amount of fuel used for each unit. GP 9 is more specific about the emissions limits for diesel engines and these are different depending on when construction commenced and the location of the construction. GP 9 and GP11 are available online at
http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp.htm.

6.11 Rhode Island

The RI Department of Environmental Management Air Pollution Control Regulation No. 5, "Fugitive Dust," regulates fugitive dust generated by numerous operations that include construction activities. The regulation is available online at
http://www.dem.ri.gov/pubs/regs/regs/air/air05_96.pdf.

Rhode Island has no regulations or laws to control emissions from diesel equipment at construction sites.

6.12 Vermont

Regulation 5-231 (4) in Vermont's Air Pollution Control Regulations addresses fugitive particulate matter emissions. The regulation states that reasonable precautions must be taken to prevent particulate matter from becoming airborne during the construction of buildings and non-public roads and the handling, transport, and storage of materials. This regulation is available online at http://www.anr.state.vt.us/air/docs/apcregs.pdf.

In addition to this rule, most of Vermont's new source permits include references to fugitive emissions. New source permits typically include language such as, "The Permittee shall take reasonable precautions at all times to control and minimize emissions of fugitive particulate matter from operations at the Facility," and list possible control measures.

Vermont has no regulations or laws to control emissions from diesel equipment at construction sites.

7. Conclusions

The following statements summarize the main points of this technical support document.

- Although a temporary source, fugitive dust and diesel emissions from construction activities can have an affect on local air quality.
- While construction activities are responsible for a relatively large fraction of direct $PM_{2.5}$ and PM_{10} emissions in the Region, the impact on visibility is less because dust settles out of the air relatively close to the sources.
- Ambient air quality data shows that soil dust makes up only a minor fraction of the $PM_{2.5}$ measured in MANE-VU Class I Areas, and impacts of diesel emissions in these rural areas are also a small part of total $PM_{2.5}$.
- The use of measures such as clean fuels, retrofit technology, best available technology, specialized permits, and truck staging areas (to limit the adverse impacts of idling) can help decrease the effects of diesel emissions on local air quality.
- MANE-VU States have rules in place to mitigate potential impacts of construction on visibility in Class I Areas.

ATTACHMENT EE

Temporary Permit for PSNH Merrimack Station

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Temporary Permit

Permit No: **TP-0008**
Date Issued: March 9, 2009
Date Reissued: August 2, 2010

This certifies that:

Northeast Utilities
Public Service of New Hampshire
780 North Commercial Street
Manchester, NH 03101

has been granted a Temporary Permit for a

Flue Gas Desulphurization System

at the following facility and location:

Public Service of New Hampshire
Merrimack Station
97 River Rd.
Bow, NH 03304-3314

Facility ID No: **3301300026**
Application No: **FY07-0103** received June 7, 2007 - Temporary Permit TP-0008
10-0136, received on June 30, 2010 - Request for the reissuance of Temporary Permit

which includes devices that emit air pollutants into the ambient air as set forth in the permit application referenced above which was filed with the New Hampshire Department of Environmental Services, Air Resources Division (Division) in accordance with RSA 125-C of the New Hampshire Laws. Request for permit renewal is due to the Division at least 90 days prior to expiration of this permit and must be accompanied by the appropriate permit application forms.

This permit is valid upon issuance and expires on **September 30, 2011**.

COPY

Director, Air Resources Division

TABLE OF CONTENTS

ABBREVIATIONS

AAL	Ambient Air Limit
AEL	Alternative Emission Limit
AP-42	Compilation of Air Pollutant Emission Factors
ARD	Air Resources Division
ASTM	American Society for Testing and Materials
ATS	Allowance Tracking System
BACT	Best Available Control Technology
BHP (or bhp)	Brake Horse Power
BTU	British Thermal Units
CAA	Clean Air Act, 42 U.S.C. § 7401, et seq.
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstracts Service
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
CTM	Conditional Test Method
DES	New Hampshire Department of Environmental Services
DER	Discrete Emission Reduction
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
Env-Wm	New Hampshire Code of Administrative Rules – Waste Management Division
ECS	Emission Control System
ERC	Emission Reduction Credit
ETS	Emissions Tracking System
FGD	Flue Gas Desulphurization
gal/hr	Gallons per hour
HAP	Hazardous Air Pollutant
HHV	High Heat Value
HCl	Hydrochloric acid
hr	Hour
kscfm	1,000 standard cubic feet per minute
kGal	1,000 gallons
KVDC	Kilovolt Direct Current
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb/hr	Pounds per hour
LNB	Low NO_x Burner
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas (Propane)
MACT	Maximum Achievable Control Technology
mmBtu	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt

ABBREVIATIONS (cont.)

NAAQS	National Ambient Air Quality Standard
NG	Natural Gas
NHDES (or DES)	New Hampshire Department of Environmental Services
NMOC	Non-Methane Organic Compound
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmdv	part per million by dry volume
PSD	Prevention of Significant Deterioration
PSI	Pounds per Square Inch
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

Facility Specific Temporary Permit Conditions

I. Facility Description of Operations

Public Service of New Hampshire - Merrimack Station is a fossil fuel-fired electricity generating facility, owned and operated by Public Service of New Hampshire (PSNH), a subsidiary of Northeast Utilities. The facility is comprised of two utility boilers, two combustion turbines operating as load shaving units, an emergency generator, an emergency boiler, and coal handling systems including primary and secondary coal crushers, coal piles, coal conveyor systems, and coal unloading from railcars. The facility operations also include various activities that are classified as insignificant or exempt activities.

The two utility boilers (MK1 and MK2) primarily burn bituminous coal, the two combustion turbines primarily burn No. 1 fuel oil or JP-4, the emergency generator burns No. 2 fuel oil or diesel fuel, and the emergency boiler burns No. 2 fuel oil or diesel fuel. PSNH – Merrimack Station ignites the utility boilers with No. 2 fuel oil.

Each boiler stack is equipped with continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS). PSNH – Merrimack Station has installed control equipment and implemented operational changes to reduce emissions, including trials of low sulfur coals to control sulfur dioxide (SO_2) emissions, selective catalytic reduction (SCR) systems to control nitrogen oxide (NO_x) emissions, and electrostatic precipitators (ESP) to control particulate matter (PM) emissions. PSNH has also initiated mercury reduction trials including carbon injection and the use of low mercury coals.

PSNH – Merrimack Station operates a fly ash reinjection system in each of the two Boilers.

II. Project Description

The Owner has filed a Temporary Permit application requesting to install a wet, limestone-based flue gas desulphurization (FGD) system to control mercury emissions from Electric Generating Units MK1 and MK2. The FGD system will also provide a co-benefit by removing sulfur dioxide emissions. The application was filed in accordance with RSA 125-O:13,I, which requires this facility to file an initial permit application by June 8, 2007. This permit establishes limits on mercury and sulfur dioxide emissions based on the requirements of RSA 125-O:13 and 40 CFR 51.308, respectively. This permit also contains applicable monitoring, performance testing, recordkeeping and reporting requirements for the purpose of ensuring that the facility can comply with the requirements of RSA 125-O:13 and 40 CFR 51.308.

Once the FGD system is constructed and operational, initial stack testing on MK1 and MK2 will be used to (1) determine whether the facility complies with the applicable mercury and sulfur dioxide limits; and (2) to establish any necessary operating parameters to ensure that the mercury and sulfur dioxide limits will be met on an ongoing basis. Periodic stack testing and/or continuous emission monitors will be used to verify that the parameters used to monitor and control mercury and sulfur dioxide emissions continue to be valid.

The facility currently operates under the application shield provisions of Env-A 609.08, *Application Shield* and in accordance with permits FP-T-0054 (MK1), TP-B-0462 (MK2), PO-B-0034 (CT1), PO-B-0035 (CT2), PO-B-1788 (Emergency Generator), TP-B-0490 (Emergency Boiler), PO-B-2416 (Primary Coal Crusher) and PO-B-2417 (Secondary Coal Crusher), which are currently in the process of being streamlined into a Title V Operating Permit. These previously issued permits will be referenced as "Previous Permits" throughout this document. This Temporary Permit includes new conditions associated with this project, and where necessary, identifies conditions of the Previous Permits that will either be modified or superseded as a result of this project. All terms and conditions of the Previous Permits not specifically identified in this permit remain in effect unchanged. Upon issuance of this permit, the Owner shall comply with all unchanged terms and conditions of the Previous Permits and all terms and conditions of this permit.

III. Permitted Activities

In accordance with all of the applicable requirements identified in this permit, the Owner is authorized to operate the devices and or processes identified in Sections IV and V within the terms and conditions specified in this Permit.

IV. Significant Activities Identification and Stack Criteria

A. Significant Activity Identification

The activities identified in Table 1 below are subject to and regulated by this Permit:

Table 1 - Significant Activity Identification			
Emission Unit Number	**Description of Emission Unit**	**Maximum Gross Heat Input Rating**	**Maximum Operating Conditions**
MK1	Steam Generating Unit 1 (Installed in 1960) Front wall firing	Bituminous Coal: 1,238 MMBtu/hr	a. Maximum fuel consumption rate of bituminous coal shall be limited to 48.5 tons/hr, not to exceed 425,289 tons during any consecutive 12 month period[1]. b. No. 2 fuel oil consumption shall be limited to 1,656 gallons per hour, not exceed 14.5 million gallons during any consecutive 12 month period[2].
MK2	Steam Generating Unit 2 (Installed in 1968) Opposed wall firing	Bituminous Coal: 3,473 MMBtu/hr	a. Maximum fuel consumption rate of bituminous coal shall be limited to 136.2 tons/hr, not to exceed 1,193,078 tons during any consecutive 12 month period[3]. b. No. 2 fuel oil consumption shall be limited to 1,656 gallons per hour, not exceed 14.5 million gallons during any consecutive 12 month period[4].

[1] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[2] No. 2 fuel oil is used to ignite individual fires before establishing the main coal fires. The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[3] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[4] No. 2 fuel oil is used to ignite individual fires before establishing the main coal fires. The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

Table 1 - Significant Activity Identification			
Emission Unit Number	**Description of Emission Unit**	**Maximum Gross Heat Input Rating**	**Maximum Operating Conditions**
MKLC1	Limestone Processing and Handling System	Not Applicable	Limestone processing rate of the wet limestone ball mills of less than 25 tons per hour[5].

B. Stack Criteria

The following devices at the Facility shall have exhaust stacks that discharge vertically, without obstruction, and meet the criteria in Table 2:

Table 2 – Stack Criteria				
Stack Number	**Emission Unit Number**	**Emission Unit Description**	**Minimum Stack Height (Feet) Above Ground Level**	**Maximum Inside Stack Diameter (Feet)**
STMK2 (Bypass Stack)	MK1	Steam Generating Unit No. 1	317	14.5
STMK3	MK1 and/or MK2 with MK2-PC7	Steam Generating Units No. 1 and/or No. 2 with FGD System	445	21.5

1. The Owner may change the stack criteria described in Table 2 with notification to DES provided that:
   i. An air quality impact analysis is performed either by the facility or DES (if requested by the facility in writing) in accordance with Env-A 606 and the "Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire," and
   ii. The analysis demonstrates that emissions from the modified stack will continue to comply with all applicable emission limitations and ambient air limits.
2. All air modeling data and analyses shall be kept on file for review by DES upon request.

V. Pollution Control Equipment/Method Identification

The devices and/or processes identified in Table 3 are considered pollution control equipment for each identified emissions unit:

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[5] Only one wet ball mill will be operated at a time. The second wet ball mill serves as a backup unit.

Table 3 – Pollution Control Equipment/Method Identification		
Pollution Control Equipment Number	Description of Equipment/Method	Emission Unit Number Controlled
MK1-PC1	Electrostatic Precipitator (ESP) #1 on MK1	MK1
MK1-PC2	ESP #2 on MK1	MK1
MK1-PC3	Selective Catalytic Reduction (SCR) deNO$_x$ System	MK1
MK2-PC4	ESP #1 on MK2	MK2
MK2-PC5	ESP #2 on MK2	MK2
MK2-PC6	SCR deNO$_x$ System	MK2
MK2-PC7	Flue Gas Desulphurization (FGD) System	MK1 and MK2

VI. Applicable Requirements

A. Operational and Emission Limitations

The Owner shall be subject to the operational and emission limitations identified in Table 4 below.

Table 4 – Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
1.	Env-A 1403	Devices subject to RSA 125-I and Env-A 1400	Devices or processes, subject to RSA 125-I and Env-A 1400, shall comply with Env-A 1400 *(Regulated Toxic Air Pollutants).*
2.	Env-A 1403.01(d)	Devices subject to RSA 125-I and Env-A 1400	Documentation for the demonstration of compliance shall be retained and shall be made available to DES for inspection upon request.
3.	Env-A 1404.01	Devices subject to RSA 125-I and Env-A 1400	a. The Owner of a new or modified device or process requiring a permit under this chapter shall submit an application for a temporary permit in accordance with Env-A 607.03. b. Pursuant to RSA 125-I:5,I, the owner shall not operate the device or process until a temporary permit is issued.
4.	Env-A 1405.01	Devices subject to RSA 125-I and Env-A 1400	The Owner of any device or process that emits an RTAP shall determine compliance with the AAL by using one of the methods provided in Env-A 1405. Upon request, the Owner of any device or process that emits an RTAP shall provide documentation of compliance with the AAL to DES.
5.	Env-A 1002.04 Fugitive Dust	MKLC1	The Owner shall prevent, abate, and control fugitive dust emissions using best management practices[6].

[6] To comply with this provision, PSNH – Merrimack Station shall use Best Management Practices to manage and minimize fugitive dust, as established in the PSNH Merrimack Station Environmental Management System Plan for Fugitive Emissions.

Table 4 – Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
6.	40 CFR 51.308(e)(1)	MK2	a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system. b. 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 will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time. c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. 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.
7.	40 CFR 51.308(e)(1)	MK2	Beginning on July 1, 2013, the Owner shall not operate MK2 unless MK2-PC7 is in operation.
8.	40 CFR 51.308 Regional Haze Plan	MK1	a. Beginning on July 1, 2013, when MK2-PC7 (FGD system) is in operation, SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal). Compliance with this percent reduction shall be determined on a calendar month average by comparing the SO_2 emission rates as measured by CEMS on the inlet and outlet of the FGD system. b. 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 will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK1. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time. c. DES shall establish the maximum sustainable rate of SO_2 emissions reductions based on a statistical analysis of the data submitted to DES pursuant to paragraph b. above. This established rate shall be incorporated as a permit condition for MK1. Under no circumstances shall the SO_2 removal efficiency for MK1 be less than 90 percent.
9.	40 CFR 51.308	MK1	Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) if MK2-PC7 is capable of stable operation.
10.	40 CFR 51.308	MK1	Beginning on July 1, 2013, the Owner shall not operate MK1 through STMK2 (bypass stack) for more than 840 hours in any consecutive 12-month period.

Table 4 – Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
11.	Env-A 1606.01(a)(1)	MK1 & MK2	For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.8 pounds per million BTU gross heat content at any time.
12.	Env-A 1606.01(a)(2)	MK1 & MK2	For coal burning devices placed in operation before April 15, 1970, the sulfur content of the coal shall not exceed 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period.
13.	RSA 125-O:13, II	Affected Sources as defined in RSA 125-O:12	Beginning on July 1, 2013, total mercury emissions from the affected sources shall be at least 80 percent less on an annual basis than the baseline mercury input, as defined in RSA 125-O:12, III.
14.	RSA 125-O:13, III	MK1 & MK2	Prior to July 1, 2013, the Owner shall test and implement, as practicable, mercury reduction control technologies or methods to achieve early reductions in mercury emissions below the baseline mercury emissions. The Owner shall report the results of any testing to DES and shall submit a plan for DES approval before commencing implementation.
15.	RSA 125-O:13-V	MK1 & MK2	a. Mercury reductions (achieved through the operation of the FGD system) greater than 80 percent shall be sustained insofar as the proven operational capability of the system, as installed, allows. b. DES, in consultation with the Owner, shall determine the maximum sustainable rate of mercury emissions reductions and incorporate such rate as a permit condition for MK1 and MK2. This requirement in no way affects the ability of the Owner to earn over-compliance credits consistent with RSA 125-O:16, II.
16.	RSA 125-O:13, VI	MK1 & MK2	The purchase of mercury emissions allowances or credits from any established emissions allowance or credit program shall not be allowed for compliance with the mercury reduction requirements of this permit or the requirements of RSA 125:O:13.
17.	RSA 125-O:13, VII	MK1 & MK2	If the mercury reduction requirement in Item 13 above is not achieved in any year after the July 1, 2013 implementation date, and after full operation of the FGD technology, then the Owner may utilize early emissions reduction credits or over-compliance credits, or both, to make up any shortfall, and thereby be in compliance.
18.	RSA 125-O:13, VIII	MK1 & MK2	If the mercury reduction requirement in Item 13 above is not achieved by the Owner in any year after the July 1, 2013 implementation date despite the Owner's installation and full operation of FGD technology, consistent with good operational practice, and the owner's exhaustion of any available early emissions reduction or over-compliance credits, then the owner shall be deemed in violation of this section unless it submits a plan to DES, within 30 days of such noncompliance, and subsequently obtains approval of that plan for achieving compliance within one year from the date of such noncompliance. DES may impose conditions for approval of such plan.

Table 4 – Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
19.	RSA 125-O:17	MK1 & MK2	Variances from mercury emissions reduction requirements: a. The Owner may request a variance from the mercury emissions reduction requirements of this permit and RSA 125-O:13, by submitting a written request to DES. The request shall provide sufficient information concerning the conditions or special circumstances on which the variance request is based to demonstrate to the satisfaction of DES that variance from the applicable requirements is necessary. b. Where an alternative schedule is sought, the Owner shall submit a proposed schedule which demonstrates reasonable further progress and contains a date for final compliance as soon as practicable. If DES deems such a delay is reasonable under the cited circumstances, it shall grant the requested variance. c. Where an alternative reduction requirement is sought, the Owner shall submit information to substantiate an energy supply crisis, a major fuel disruption, an unanticipated or unavoidable disruption in the operations of the affected sources, or technological or economic infeasibility. DES, after consultation with the New Hampshire Public Utilities Commission, shall grant or deny the requested variance. If requested by the Owner, DES shall provide the owner with an opportunity for a hearing on the request.
20.	RSA 125-O:16, I	MK1 & MK2	Economic Performance Incentives/Generation and Use of Early Emissions Reduction Credits: a. DES shall issue to the Owner early emissions reduction credits in the form of credits or fractions thereof for each pound of mercury or fraction thereof reduced below the baseline mercury emissions, on an annual basis, in the period prior to July 1, 2013. b. Ratios of early reductions credits to pounds of mercury reduced shall be as follows: i. 1.5 credits per pound reduced prior to July 1, 2008; ii. 1.25 credits per pound for reductions between July 1, 2008 and December 31, 2010; and iii. 1.1 credits per pound for reductions between January 1, 2011 and July 1, 2013. c. Reductions shall be calculated based upon the results of stack tests conducted, measurement by continuous emission monitoring, or other methodology approved by DES to confirm emissions during the time of operation of mercury reduction technology. d. Early emissions reduction credits may be banked by the Owner or utilized after July 1, 2013 to meet the reduction requirement of RSA 125-O:13, II as allowed under RSA 125-O:13, VII. e. Early emissions reduction credits are not sellable or transferable to non-affected sources; however, upon the July 1, 2013 compliance date, the Owner may request a one-for-one conversion of early emissions reduction credits to over-compliance credits.

Table 4 – Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
			f. Should a federal rule applicable to mercury emissions at one or more of the affected sources be enacted with an implementation date prior to July 1, 2013, then early reduction credits may only be earned for emissions reductions that exceed the level required by the federal rule of the affected sources in aggregate or the baseline mercury emissions level, whichever is lower, at the same ratios listed in subparagraph (b) above. g. Early emissions reduction credits shall not be used for compliance with the requirement of RSA 125-O:13, II prior to the installation of FGD technology, and shall not be used as a means to delay the installation of the FGD technology.
21.	RSA 125-O:16, II	MK1 & MK2	Economic Performance Incentives/ Use of Over-Compliance Credits: a. DES shall issue to the Owner over-compliance credits in the form of credits or fractions thereof for each pound of mercury or fraction thereof reduced in excess of the emissions reduction requirement of RSA 125-O:13, II, on an annual basis, following the compliance date of July 1, 2013. b. The ratios of over-compliance credits to excess pounds of mercury reduced shall be as follows: i. 0.5 credits per pound reduced for reductions between 80 and 85 percent; ii. 1 credit per pound reduced for reductions between 85 and 90 percent reduction; and iii. 1.5 credits per pound reduced for reductions of 90 percent or greater. c. Over-compliance credits may be banked for future use. The requirements of RSA 125-O:13, V shall not alter the emissions levels at which over-compliance credits are earned. d. Should a federal rule applicable to mercury emissions at one or more of the affected sources be enacted, then over-compliance credits may only be earned for emissions reductions that exceed the level required by the federal rule of the affected sources in aggregate or the requirement of RSA 125-O:13, II, whichever is lower, at the same ratios listed in subparagraph (b) above. e. At the request of the Owner, over-compliance credits may be surrendered by the owner to the department and SO2 allowances shall be transferred to the owner at a rate of 55 tons SO2 allowances for every one over-compliance credit. Transfer shall be limited to a maximum of 20,000 total tons SO2 allowances transferred in a given year, defined as the sum of all SO2 allowances received by the affected sources under RSA 125-O:4, IV(a)(2) and IV(a)(3), and under this subparagraph. SO2 allowances shall be credited to the affected sources' accounts in the following year in accordance with RSA 125-O:4, IV(a)(4).

Table 4 – Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
22.	Env-A 604.02	MKLC1	The limestone processing rate of the wet limestone ball mills shall not exceed 25 tons per hour[7].

B. Initial Compliance Demonstration Requirements

The Owner shall demonstrate initial compliance with the emission limitations specified in Table 4 for the parameters contained in Table 5 below, within 60 days after achieving stable FGD operation with both MK1 and MK2 exhausting through stack STMK3. The Owner shall perform the initial compliance demonstration requirements listed in Table 5 below. In addition, the Owner shall perform all monitoring and testing requirements in Table 6 to ensure compliance with emissions and operating limitations contained in Table 4.

Table 5: Initial Compliance Demonstration Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Basis**
1.	MK1 & MK2 with MK2-PC7	Performance tests for mercury	a. The Owner shall conduct initial performance tests for mercury to demonstrate compliance with the respective mercury emissions limitation in Table 4, Item 13. b. Testing shall be conducted and the results reported in accordance with 40 CFR 60, Sections 60.8(a), (b), (d), (e), and (f), and Appendix A. The following test methods or DES approved alternatives shall be used for the pollutants specified: i. Method 1 or 2 to determine exit velocity of stack gases; ii. Method 3 or 3A to determine carbon dioxide, oxygen, excess air, and molecular weight (dry basis) of stack gases; iii. Method 4 to determine moisture content (volume fraction of water vapor) of stack gases;	Within 60 days after achieving stable FGD operation with both MK1 and MK2 exhausting through stack STMK3	Env-A 802 & 40 CFR 60.8 (a), (b), (d)-(f)

[7] The limestone processing equipment subject to this requirement consists of two wet limestone ball mills. Only one wet limestone ball mill is operated at a time. The second wet limestone ball mill will serve as a backup unit.

Table 5: Initial Compliance Demonstration Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Basis**
			iv. For mercury, in accordance with the mercury monitoring requirement of RSA 125-O:15 and Table 6, Item 3 of this permit.		
2.	MK1 & MK2	Performance Test for SO_2	a. The Owner shall conduct an initial performance test for SO_2 to demonstrate compliance with the respective SO_2 emissions limitation in Table 4, Items 6 and 8. b. Testing shall be conducted and the results reported in accordance with 40 CFR 60, Sections 60.8(a), (b), (d), (e), and (f), and Appendix A. The following test methods or DES approved alternatives shall be used for the pollutants specified: i. Use of certified CEMS monitors. With the use of CEMS monitors, compliance will be determined based on a monthly average of CEMS data.	Within 60 days after achieving stable FGD operation with both MK1 and MK2 exhausting through stack STMK3	Env-A 802 & 40 CFR 60.8 (a), (b), (d)-(f)
3.	MK1 & MK2	General Stack Testing Requirements	Compliance testing shall be planned and carried out in accordance with the following schedule: a. At the request of DES, submit to DES a pretest protocol at least 30 days prior to the commencement of testing which includes the following information: i. Calibration methods and sample data sheets; ii. Descriptions of the test methods to be used; iii. Pre-test preparation procedures; iv. Sample collection and analysis procedures; v. Process data to be collected; and vi. Complete test program description. b. At the request of DES, participate in a pretest conference with a DES representative at least 15 days prior to the test date. c. Emission testing shall be carried out under the observation of a DES representative. d. Within 60 days after completion of testing or within 15 days of receipt of test report, submit a copy of the test report to DES.	Initial performance test and subsequent testing	Env-A 802.03, 802.04, 802.05, & 802.11
4.	MK1 & MK2	General Stack Testing Requirements	*Operating Conditions During a Stack Emissions Test* A compliance test shall be conducted under one	Initial performance test and	Env-A 802.10

Table 5: Initial Compliance Demonstration Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Basis**
			of the following operating conditions: a. Between 90 and 100 % of maximum operating capacity; b. A production rate at which maximum emissions occur; or c. At such operating conditions agreed upon during a pre-test meeting conducted pursuant to Env-A 802.05.	subsequent tests	

C. Monitoring/Testing Requirements

1. The Owner is subject to the monitoring/testing requirements as contained in Table 6 below:

Table 6 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	MK1 & MK2	Continuous Emissions Monitoring Systems	*Site-Specific Monitoring Plan - Continuous Emissions Monitoring Systems* a. The Owner shall submit a CEMS monitoring plan describing the proposed systems. The monitoring plan shall contain the information required under Env-A 808.04(c) and address all applicable monitoring requirements of Env-A 808, 40 CFR Part 60, and 40 CFR Part 75. b. The CEMS monitoring plan in item a above, shall at a minimum, address the following operating scenarios: i. CEMS monitoring for units MK1 and MK2 when both units MK1 and MK2 are operating and emissions are discharged through the common exhaust stack STMK3; ii. CEMS monitoring for compliance with the SO_2 limitation specified in Table 4, Item 6 and 8; iii. Monitoring for unit MK1 when emissions are discharged through stack STMK2 (bypass stack).	At least 90 days prior to the installation of the CEM system	Env-A 808.04(a)
2.	MK1 & MK2	Continuous Emissions Monitoring Systems	*Quality Assurance/Quality Control Plan Requirements* The Owner of a source required by this part to install, operate, and maintain an opacity or gaseous	As specified within regulation	Env-A 808.06

Table 6 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			CEMS shall: a. Prepare a quality assurance/quality control (QA/QC) plan, which shall contain written procedures for implementation of its QA/QC program for each CEMS; b. File the QA/QC plan with DES no later than the time specified in Env-A 808.05(e) after the initial startup of each CEMS; c. Review the QA/QC plan and all data generated by its implementation at least once each year; d. Revise or update the QA/QC plan, as necessary, based on the results of the annual review, by: ii. Documenting any changes made to the CEMS or changes to any information provided in the monitoring plan; iii. Including a schedule of, and describing, all maintenance activities that are required by the CEMS manufacturer or that might have an effect on the operation of the system; iiii. Describing how the audits and testing required by this part will be performed; and iiv. Including examples of the reports that will be used to document the audits and tests required by this part; e. Make the revised QA/QC plan available for review by DES at any time; and f. Within 30 days of completion of the annual QA/QC plan review, certify in writing that the Owner will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reasons for each change; g. Revision of the QA/QC plan is required if the results of emission report reviews, inspections, audits, review of the QA/QC plan, or any other information available to DES show that the plan does not meet the criteria specified in 40 CFR 60, Appendix F, Procedure 1, section 3; and h. The QA/QC plan shall be considered an update to the CEMS monitoring plan		

Table 6 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			required by Env-A 808.04.		
3.	MK1 & MK2	Mercury Emissions	*Monitoring of Mercury Emissions* a. Prior to the availability and operation of CEMS, and subsequent to the baseline emissions testing under RSA 125-O:14, II, stack tests or another methodology approved by DES shall be conducted twice per year to determine mercury emissions levels from the affected sources. b. Any stack tests performed shall employ a federally recognized and approved methodology, proposed by the Owner and employing a test protocol approved by DES. c. When a federal performance specification takes effect and a mercury CEMS capable of meeting the federal specifications becomes available, a mercury CEMS, approved by DES, shall be installed on STMK3 as deemed appropriate by DES.	Twice per year or until a mercury CEMS is in operation and approved by DES	RSA 125-O:15
4.	MK1 & MK2	Stack flow, NO_x, SO_2, and CO_2 (or O_2), opacity	The new stack (STMK3 from the FGD) serving units MK1 and MK2 shall be equipped with flow monitoring, NO_x, SO_2, and CO_2 or O_2 CEMS and a continuous opacity monitor (COMS)[8]. The CEMS and COMS shall meet 40 CFR 75 requirements.	Continuously	Env-A 808.02(a) (new) and 40 CFR 75 §75.10(a)(2), §75.12, and Env-A 1211.03(f)
5.	MK2-PC7	FGD Operating Parameters	a. The Owner shall continuously monitor the scrubber liquor pH and FGD absorber exit gas temperature. b. The Owner shall calibrate or validate the accurate operation of the instruments measuring the parameters a minimum of once annually in accordance with manufacturer's recommended procedures or alternative procedures as approved by DES. All records of the calibrations or validations shall be kept and made available upon request.	Continuously	RSA 125-C:6, XI
6.	MK2-PC7	FGD Data Acquisition System	The Owner shall have a data acquisition system for the FGD absorber exit gas temperature and scrubber liquor pH monitors, which calculates and monitors hourly averages and daily averages.	Continuously	RSA 125-C:6, XI

8 Due to excessive moisture in the flue gas exiting the FGD system, the COMS will be installed prior to the stack.

Table 6 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
7.	MK1 & MK2	Sulfur Test Method for Coal	The owner or operator shall use Method ASTM D 4239-00 to determine the sulfur content of coal in pounds of sulfur per million BTU gross heat content.	Each shipment of coal	Env-A 806.04

D. Recordkeeping Requirements

The Owner is subject to the Recordkeeping requirements as contained in Table 7 below:

Table 7 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
1.	*Record Retention and Availability* The Owner shall keep the required records on file. These records shall be available for review by DES upon request.	Retain for a minimum of 5 years	Emissions Units specified in Table 1 and Pollution Control Equipment specified in Table 3	Env-A 902
2.	*General Recordkeeping Requirements for Process Operations* The Owner shall keep monthly records of: a. The quantity of limestone used as documented by limestone delivery records; and b. The hours of operation of the wet limestone ball mills.	Monthly	MKLC1 MK2-PC7	Env-A 903.02
3.	The Owner shall maintain the standard operating and maintenance procedures for the air pollution control equipment in a convenient location (e.g., control room/technical library) and make them readily available to DES upon request.	Maintain at facility at all times	MK2-PC7	Env-A 906.01
4.	*CEMS and Other Approved Monitoring Methods Recordkeeping Requirements* a. The Owner shall record and maintain the information pursuant to 40 CFR Part 75, which includes the certification, quality assurance, and quality control records. b. The Owner shall record and maintain CEMS records according to the most stringent requirements of Env-A 808 and 40 CFR Part 75.	As specified by regulation	MK1, MK2, MK2-PC7	Env-A 903.04 Env-A 808 40 CFR Part 75

Table 7 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
5.	The Owner shall record the hours of operation of MK1 and MK2 as follows: a. Total hours of MK1 and MK2 each; and b. Total hours of MK1 when discharging through STMK2 (bypass stack)	Monthly	MK1 and MK2	Env-A 906
6.	The owner or operator shall maintain the following sulfur analysis records: a. Records showing the maximum weight percentage sulfur and quantity of each fuel delivery shipment received; and b. Records showing either: 1. The analytical method used and the specified fuel analysis results of the shipment or consignment from which the shipment came; or 2. Delivery records sufficient to allow for traceability of the analytical results corresponding to each shipment received by the stationary source, showing: i. The date of delivery; ii. The quantity of delivery; iii. The type of fuel; iv. The maximum weight percentage sulfur; and v. The name, address, and telephone number of the company making the delivery.	Each shipment of coal	MK1 & MK2	Env-A 806.05

E. Reporting Requirements

The Owner is subject to the reporting requirements identified in Table 8 below:

Table 8 – Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
1.	*Performance Test Reports* The Owner shall submit a report to DES documenting the results of the compliance stack emission test. The compliance stack emission test report shall contain the following information: a. All the information required for the pre-test protocol as described in Env-A 802.04; b. All test data; c. All calibration data; d. Process data agreed by DES and the Owner to be collected; e. All test results; f. A description of any discrepancies or problems that occurred during testing or sample analysis; g. An explanation of how discrepancies or problems were treated and their effect on the final results; and h. A list and description of all equations used in the test report, including sample calculations for each equation used.	No later than 60 days after a performance test	MK1, MK2 & MK2-PC7	Env-A 802.11
2.	*Quarterly Reports* The Owner shall submit to DES no later than 30 calendar days after the end of the calendar quarter, the information required in Table 7, Item 4.	Quarterly – 30 calendar days after the end of the calendar quarter	MK1, MK2, MK2-PC7	40 CFR 75, Env-A 808.11
3.	*Semi-annual Report* The Owner shall submit to DES the following information on a semi-annual basis: a. Hours of operation of MK1 and MK2 as required in Table 7, Item 5; and b. Limestone records as required in Table 7, Item 2.	Semi-annual	MK1, MK2, MKLC1	Env-A 910
4.	*Annual Emissions Compliance Report for Mercury* The Owner shall submit to DES a report of annual mercury emissions from the affected sources to demonstrate compliance with Item 13 of Table 4. This report shall include all references and methodologies used to calculate the total mercury emissions from the affected sources.	Annually by April 15th of each calendar year	Affected Sources as defined in RSA 125-O:12	Env-A 910

Table 8 – Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
5.	*Quarterly Coal Report* The Owner shall submit to DES no later than 30 calendar days after the end of the calendar quarter, the information required in Table 7, Item 6. Submittal of the "Monthly Report of Cost and Quality of Fuel for Electric Plants," will satisfy the requirements of this condition.	Quarterly – 30 calendar days after the end of the calendar quarter	MK1 & MK2	Env-A 910.01

VII. Administrative Permit Amendments

A. Pursuant to Env-A 612.01, the Owner may implement the changes addressed in the request for an administrative permit amendment as defined in Part Env-A 100 immediately upon submittal of the request.

B. Pursuant to Env-A 612.01, the Director shall take final action on a request for an administrative permit amendment in accordance with the provisions of Env-A 612.01(b) and (c).

VIII. Minor Permit Amendments

A. Pursuant to Env-A 612.03, the owner or operator of a source or device shall submit to the department a request for a minor permit amendment for any proposed change to an existing permit condition which will not result in an increase in the amount of a specific air pollutant currently emitted by the source or device and will not result in the emission of any regulated air pollutant or regulated toxic air pollutant currently not emitted by the source or device.

B. The request for a minor permit amendment shall:
1. Be in the form of a letter to the department;
2. Describe the proposed change; and
3. Describe any new applicable requirements that will apply if the change occurs.

C. The department shall take final action on a request for a minor permit amendment within 90 days of receipt of such a request.

D. The owner or operator may implement the proposed change immediately upon filing a request for minor permit amendment with the department.

IX. Significant Permit Amendments

A. Pursuant to Env-A 612.04, the owner or operator shall submit an application to the department for a significant permit amendment for any proposed change to the physical structure or operation of the source or device covered by the temporary permit which increases the amount of a specific air pollutant currently emitted by such source or device or which results in the emission of any regulated air pollutant currently not emitted by such source or device.

B. A request for a significant permit amendment shall include the following:

1. A complete application form, as described in Env-A 1703 through Env-A 1708, as applicable and provided by the department, containing all pertinent information with regard to the amendment including, if applicable, the information specified in Env-A 1709.

2. The fee(s) specified in Env-A 702 through Env-A 705, as applicable.

3. A description of:
   a. The proposed change;
   b. The emissions resulting from the change; and
   c. Any new applicable requirements that will apply if the change occurs: and

4. Where air pollution dispersion modeling is required for a source or device pursuant to Env-A 606.02, the information required pursuant to Env-A 606.03.

C. The department shall take take final action on a request for a significant permit amendment within 90 days of receipt of such a request, provided that the public notice and hearing procedures specified in Env-A 621 have been satisfied.

D. The owner or operator shall not implement the proposed change until the department issued the amended permit.

X. <u>Emission-Based Fee Requirements</u>

A. The Owner shall pay an emission-based fee quarterly for this facility as calculated each calendar year pursuant to Env-A 705.03.

B. The Owner shall determine the total actual annual emissions from the facility to be included in the emission-based multiplier specified in Env-A 705.03(a) for each calendar year in accordance with the methods specified in Env-A 616.

C. The Owner shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT * CPIm * ISF$$

Where:

FEE =	The annual emission-based fee for each calendar year as specified in Env-A 705.
E =	The emission-based multiplier is based on the calculation of total annual emissions as specified in Env-A 705.02 and the provisions specified in Env-A 705.03(a).
DPT =	The dollar per ton fee the DES has specified in Env-A 705.03(b).
CPIm=	The Consumer Price Index Multiplier as calculated in Env-A 705.03(c).
ISF =	The Inventory Stabilization Factor as specified in Env-A 705.03(d).

D. The Owner shall contact the DES each calendar year for the value of the Inventory Stabilization Factor.

E. The Owner shall contact the DES each calendar year for the value of the Consumer Price Index Multiplier.

F. The Owner shall submit, to the DES, payment of the emission-based fee and a summary of the calculations referenced in Sections X.B. and C. of this Permit for each calendar year. The total emission-based fee shall be paid in four equal installments on a quarterly basis. The quarterly payments shall be made in accordance with Env-A 705.04 on the 15^{th} day of the following months:

   1. July of the year to which the fee applies (e.g., January, February, March 2007 emission fees are due July 15, 2007);

   2. October of the year to which the fee applies (e.g., April, May, June 2007 emission fees are due on October 15, 2007).

   3. January of the following year (e.g., July, August, September 2007 emission fees are due on January 15, 2008);

   4. April of the following year (e.g., October, November, December 2007 emission fees are due on April 15, 2008).

   The Owner shall pay any remaining balance of the total annual emission-based fee no later than April 15^{th} of the following year.

   The emission-based fee and summary of the calculations shall be submitted to the following address:

   New Hampshire Department of Environmental Services
   Air Resources Division
   29 Hazen Drive
   P.O. Box 95
   Concord, NH 03302-0095
   ATTN.: Emissions Inventory

G. The DES shall notify the Owner of any under payments or over payments of the annual emission-based fee in accordance with Env-A 705.05.

XI. Permit Deviation

In accordance with 40 CFR 70.6(a)(3)(iii)(B), the Owner shall report to the DES all instances of deviations from Permit requirements, by telephone, fax, or e-mail (pdeviations@des.state.nh.us) within 24 hours of discovery of such deviation. This report shall include the deviation itself, including those attributable to upset conditions as defined in this Permit, the probable cause of such deviations, and any corrective actions or preventative measures taken.

Within 10 days of discovery of the permit deviation, the Owner shall submit a written report including the above information as well as the following: preventive measures taken to prevent future occurrences; date and time the permitted device returned to normal operation; specific device, process or air pollution control equipment that contributed to the permit deviation; type and quantity of excess emissions emitted to the atmosphere due to permit deviation; and an explanation of the calculation or estimation used to quantify excess emissions.

Said Permit deviation shall also be submitted in writing to the DES in the semi-annual summary report of monitoring and testing requirements due July 31st and January 31st of each calendar year. Deviations are instances where any Permit condition is violated and has not already been reported as an emergency pursuant to 40 CFR 70.6(g).

Reporting a Permit deviation is not an affirmative defense for action brought for noncompliance.

ATTACHMENT FF

Revisions to Env-A 1604, Sulfur Content Limitations for Liquid Fuels (Draft)

The ***MANE-VU Low-Sulfur Fuel Strategy*** calls for the following:

Reduce the sulfur content of distillate oil to 0.05% sulfur by weight (500 ppm) by no later than 2014, of #4 residual oil to 0.25-0.5% sulfur by weight by no later than 2018, and of #6 residual oil to no greater than 0.5% sulfur by weight by no later than 2018, and to reduce the sulfur content of distillate oil further to 15 ppm by 2018.

Proposed revisions to:

CHAPTER Env-A 1600 FUEL SPECIFICATIONS

PART Env-A 1604 SULFUR CONTENT LIMITATIONS FOR LIQUID FUELS

Env-A 1604.01 Maximum Sulfur Content Allowable in Liquid Fuels.

(a) The sulfur content of No. 2 oil and JP-4 aviation fuel shall not exceed 0.40 percent sulfur by weight.

(b) The sulfur content of No. 4 oil shall not exceed 1.00 percent sulfur by weight.

(c) The sulfur content of No. 5 oil, No. 6 oil, and crude oil shall not exceed the following limits:

(1) Where such fuel is used in Coos county, 2.20 percent sulfur by weight; and

(2) Where such fuel is used anywhere else in the state, 2.00 percent sulfur by weight.

(d) The sulfur content of aviation gasoline shall not exceed 0.05 percent sulfur by weight.

(e) The sulfur content of kerosene-1 oil shall not exceed 0.04 percent sulfur by weight.

(f) The sulfur content of kerosene-2 oil and Jet A, A-1, B, and JP-8 aviation fuels shall not exceed 0.30 percent sulfur by weight.

(g) The sulfur content of used oil shall not exceed 2.00 percent sulfur by weight.

(h) Beginning on July 1, 2013, and ending on June 30, 2017, the sulfur content of No. 5 oil, No. 6 oil, used oil, and crude oil shall not exceed 1.00 percent sulfur by weight.

(i) Beginning on July 1, 2013, and ending on June 30, 2017, the sulfur content of No. 2 oil shall not exceed 0.05 percent sulfur by weight.

(j) On or after July 1, 2017, the sulfur content of No. 2 oil shall not exceed 0.0015 percent sulfur by weight.

(k) On or after July 1, 2017, the sulfur content of No. 4 oil shall not exceed 0.25 percent sulfur by weight.

(l) On or after July 1, 2017, the sulfur content of No. 5 oil, No. 6 oil, used oil, and crude oil shall not exceed 0.50 percent sulfur by weight.

[proposed changes in *italics*]

ATTACHMENT GG

Chapter Env-A 2300, Mitigation of Regional Haze

EVIDENCE OF THE RULE'S ADOPTION

40 CFR Part 51, Appendix V, 2.1(b)

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

January 7, 2011

Carol J. Holahan, Director
c/o OLS, Division of Administrative Rules
State House Annex, Room 219
Concord, NH 03301

Re: Adoption of Final Rules, FP # 2010-113

Dear Director Holahan:

Please be advised that I, as Commissioner of the Department of Environmental Services, have adopted the following rules:

Env-A 2300: Mitigation of Regional Haze

The Joint Legislative Committee on Administrative Rules approved these rules at its meeting on January 7, 2011.

A copy of the adopted rules is being filed electronically, concurrent with the e-filing of this adoption letter. The original, signed adoption letter is being sent separately by messenger mail for your records.

I, Thomas S. Burack, Commissioner of the Department of Environmental Services, hereby certify that the enclosed are true copies of the rules I have adopted.

Sincerely,

Thomas S. Burack

Thomas S. Burack
Commissioner

Enclosures

cc: Gretchen Hamel, DES Legal Unit
DES Public Information and Permitting Office

ec: K. Allen Brooks, Chief, AGO-Environmental Protection Bureau
Karla McManus, DES ARD

COPY OF THE ACTUAL RULE

40 CFR Part 51, Appendix V, 2.1(d)

As of January 8, 2011, CHAPTER Env-A 2300 reads as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

Env-A 2301.03 Definitions.

(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

(h) "Total suspended particulate matter (TSP)" means particulate matter as measured by the high-volume method described in Appendix B of 40 CFR Part 50.

(i) "Visibility impairment" means "visibility impairment" as defined in 40 CFR 51.301, namely "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

PART Env-A 2302 EMISSION STANDARDS FOR MITIGATION OF REGIONAL HAZE

Env-A 2302.01 Emission Standards Applicable to Cyclone-Firing, Wet-Bottom Boilers.

(a) For any cyclone-firing, wet-bottom boiler subject to this chapter whose maximum heat input rate is less than or equal to 3,000 million BTUs per hour, the following emission rates shall apply:

(1) SO_2 emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600;

(2) NOx emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600; and

(3) Beginning on July 1, 2013, TSP emissions shall not exceed 0.08 lb per million BTUs, demonstrated by completion of periodic stack tests as specified in Env-A 2304.01(b) on the outlet side of the final emission control device.

(b) For any cyclone-firing, wet-bottom boiler subject to this chapter whose maximum heat input rate is greater than 3,000 million BTUs per hour, the following emission rates shall apply:

(1) SO_2 emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600;

(2) Beginning on July 1, 2013, NOx emissions shall not exceed 0.30 lb per million BTUs on a 30-day rolling average basis as recorded by a continuous emissions monitoring system (CEMS) as specified in Env-A 2303; and

(3) Beginning on July 1, 2013, TSP emissions shall not exceed 0.08 lb per million BTUs, demonstrated by completion of periodic stack tests as specified in Env-A 2304.01(b)on the outlet side of the final emission control device.

Env-A 2302.02 Emission Standards Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, the following emission rates shall apply:

(a) Beginning on July 1, 2013, SO_2 emissions shall not exceed 0.50 pound (lb) per million BTUs on a 30-day rolling average basis as recorded by a CEMS as specified in Env-A 2303;

(b) NOx emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600; and

(c) TSP emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600.

PART Env-A 2303 CONTINUOUS EMISSIONS MONITORING SYSTEMS

Env-A 2303.01 Requirements for Continuous Emissions Monitoring Systems. The owner or operator of a source whose emissions are required to be monitored and recorded by a CEMS as provided in Env-A 2302.01 or Env-A 2302.02 shall:

(a) Install, calibrate, operate, maintain, and perform quality assurance testing of the CEMS in accordance with Env-A 808; and

(b) Comply with recordkeeping requirements for CEMS specified in Env-A 903.04.

PART Env-A 2304 PERFORMANCE TESTING

Env-A 2304.01 Performance Testing Requirements Applicable to Cyclone-Firing, Wet-Bottom Boilers. For any cyclone-firing, wet-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions and NOx emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Periodic stack tests for TSP emissions shall be conducted in accordance with Env-A 802, subject to the following:

(1) For an initial period of 3 years, stack tests shall be conducted annually, with the first stack test to be completed by June 30, 2013;

(2) Beginning on July 1, 2015, stack tests shall be conducted every other year, with the fourth stack test to be completed by June 30, 2017; and

(3) At any facility where an affected unit shares a common stack with a second affected unit, the stack emissions shall be tested as from one source, by either of the following methods:

a. With both units operating simultaneously, a stack test on the combined emissions from both units, or

b. With one unit operating at a time, separate stack tests on the emissions from each unit.

Env-A 2304.02 Performance Testing Requirements Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions, NOx emissions, and TSP emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Any stack test required to demonstrate compliance with this part shall be conducted in accordance with Env-A 802.

Appendix

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

EVIDENCE THAT NEW HAMPSHIRE FOLLOWED ALL PROCEDURAL REQUIREMENTS

40 CFR Part 51, Appendix V, 2.1(e)

REQUEST FOR FISCAL IMPACT STATEMENT

STATE OF NEW HAMPSHIRE

DATE September 17, 2010

FROM Thomas S. Burack
Commissioner

AT (OFFICE) DES

SUBJECT Request for Fiscal Impact Statement

TO Legislative Budget Assistant

In accordance with NH RSA 541-A:5, enclosed please find a Request for Fiscal Impact Statement and a copy of the corresponding administrative rules for the following:

Env-A 2300: Mitigation of Regional Haze

Please fax the Fiscal Impact Statement to Gretchen Hamel at 271-8805.

If you have any questions, please contact Gretchen Hamel at 271-3137.

cc: Gretchen Hamel, Administrator, DES Legal Unit
ec: Karla McManus, ARD Planning and Rules Manager

OFFICE OF LEGISLATIVE BUDGET ASSISTANT
REQUEST FOR FISCAL IMPACT STATEMENT (FIS)

FIS Number ______ Rule Number Env-A 2300

1. Agency Name & Address: Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	2. RSA Authority: RSA 125-C:4, I(a), (b), (k) 3. Federal Authority: 42 U.S.C. §7491; 40 CFR 51.308 4. Type of Action: Adoption X Amendment ____ Repeal ____ Readoption ____ Readoption w/amendment ____ Interim rule ____ 5. Have the rules expired? Yes ☐ No ☒ Date Expired: ______

6. Short Title: Mitigation of Regional Haze

7. Contact Person:

Name:	Gretchen Hamel	Title:	Administrator, Legal Unit
Address:	Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	Phone #: Fax #:	271-3137 271-8805

(1) Summarize the rule.

Regional haze is a visibility impairment caused by the emission of air pollutants from numerous sources located over a wide geographic area. Section 169A of the Clean Air Act (42 U.S.C. §7491) mandates visibility protection for federal Class I federal areas, which include 156 national parks and wilderness areas. Regionally, Class I areas include the Great Gulf and Presidential Range - Dry River Wilderness and Acadia National Park. The proposed rules, Chapter Env-A 2300, Mitigation of Regional Haze, establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired power plants that contribute to regional haze. Subtitle Env-A already contains rules govern haze-causing pollutants, including SO2, NOx, and TSP; the proposed rules would supplement those requirements and make the emission limitations for the 3 named pollutants more stringent for the sources that would be subject to the rules. Specifically, the rules will establish new emission limits for SO2, NOx, and TSP to be effective on July 1, 2013 for any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a cyclone-firing, wet-bottom boiler fueled by coal (or any combination of fuels using coal) or a tangential-firing, dry-bottom boiler fueled by oil or gas (or any combination of oil or gas).

(2) Is the cost associated with this rule mandated by the rule or by state statute? If the cost is mandated by statute, then the rule itself may not have a cost or benefit associated with it. Please state either the statute or chapter law that is instigating this rule.

The State is required by 42 U.S.C. §7491 and 40 CFR Part 51, Subpart P Protection of Visibility (specifically, 40 CFR §51.308) to develop a program to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas in which impairment results from manmade air pollution. RSA 125-C:4 requires the commissioner to adopt rules relative to, *inter alia*, the prevention, control, abatement, and limitation of air pollution; primary and secondary ambient air quality standards; and procedures for air testing and monitoring and recordkeeping. The proposed rules are the most cost-effective way to comply with the state and federal statutory requirements. The rules are being adopted under RSA 125-C:4, I(a), (b), and (k) to implement RSA 125-C:1 and the federal regional haze requirements.

(3) Compare the cost of the proposed rule with the cost of the existing rule, if there is an existing rule.

The proposed rules could result in increased costs to the three emission units that will be subject to them. However, two of the three units will be capable of meeting the proposed emission requirements with existing emission controls and with additional controls already under construction as required by other state law, and the third will be capable of meeting these emission requirements with existing emission controls and with reasonable adjustments to the sulfur content of its residual fuel oil and/or to the fuel oil/natural gas ratio used in combustion. Because DES cannot predict the costs of fuel in 2013, no estimate of any potential cost increment can be made.

(4) Describe the costs and benefits to the state general fund which would result from this rule.

There would be no costs or benefits to the state general fund as a result of this rule.

(5) Explain and cite the federal mandate for the proposed rule, if there is such a mandate. How would the mandate affect state funds?

The Clean Air Act, Section 169A (42 U.S.C. §7491) states that Congress has declared "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." States' requirements to achieve this goal are established in 40 CFR Part 51, Subpart P (§§51.300-309). Required SIP elements are described in 40 CFR 51.308, Regional Haze Program Requirements. These include provisions at 40 CFR 51.308(e) for Best Available Retrofit Technology (BART), affecting certain older, fossil-fuel-fired power plants. If DES does not adopt the rules, New Hampshire will be out-of-compliance with the federal requirements for the regional haze program and EPA could impose sanctions, including the loss of federal transportation funding.

(6) Describe the cost and benefits to any state special fund which would result.

There would be no significant cost or benefit to any state special fund as a result of the proposed rules. Although the owner of the affected facilities pays emission-based fees, emissions are already controlled to approximately the same level as will be required.

(7) Describe the costs and benefits to the political subdivisions of the state.

There will be no costs to political subdivisions of the state as a result of the proposed rules, as none of the affected emissions units are owned or operated by political subdivisions. It is unlikely that there will be measurable benefits, although political subdivisions in areas expected to benefit from the rules could see an increase in tourism-related revenues.

(8) Describe the costs and benefits to the citizens of the state.

The proposed rules are not expected to result in any costs or benefits to citizens of the state in general. Citizens may benefit from improved visibility resulting from the lower emission limits for SO_2, NOx, and TSP which are being imposed as a result of the Clean Air Act, 42 U.S.C. §7491.

(9) Describe the costs and benefits to any independently owned business, including a description of the specific reporting and recordkeeping requirements upon those employing fewer than 10 employees.

The proposed rules are not expected to result in any costs or benefits to independently owned businesses, as the only business that owns emissions units that will be subject to the rule is PSNH.

The rules do not contain any reporting or recordkeeping requirements.

Adopt CHAPTER Env-A 2300 to read as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

Env-A 2301.03 Definitions.

(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

(h) "Total suspended particulate matter (TSP)" means particulate matter as measured by the high-volume method described in Appendix B of 40 CFR Part 50.

(i) "Visibility impairment" means "visibility impairment" as defined in 40 CFR 51.301, namely "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

FISCAL IMPACT STATEMENT

LBAO
FIS 10:126
09/22/10

Fiscal Impact Statement for Department of Environmental Services rules governing Mitigation of Regional Haze. [Env-A 2300]

1. **Comparison of the costs of the proposed rule(s) to the existing rule(s):**
   When compared to the existing rules, the proposed rules may increase costs to independently owned businesses by an indeterminable amount.

2. **Cite the Federal mandate. Identify the impact on state funds:**
   The Clean Air Act, Section 169A (42 USC § 7491) and 40 CFR Part 51, Subpart P Protection of Visibility require the state to develop a program to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory class I federal areas in which impairment results from manmade air pollution. If the proposed rules are not adopted, the State would be out of compliance with federal requirements that could result in the US Environmental Protection Agency imposing sanctions, including the loss of federal transportation funding.

3. **Cost and benefits of the proposed rule(s):**
   The Department notes there are three emission units, all owned by Public Service of New Hampshire (PSNH), that will be subject to these rules. PSNH may experience increased costs to the three emission units, however the Department indicates that two of the three units will be capable of meeting the proposed emission requirements with existing emission controls and with additional controls already under construction to meet state law. The Department further indicates the third emission unit will be able to meet the emission requirements with existing emission controls and reasonable adjustments to the sulfur content of its residual fuel oil and/or to the fuel oil/natural gas ratio used in combustion. The Department has no information on FY 2013 fuel costs to estimate any potential increase in cost.

   A. **To State general or State special funds:**
      None.

   B. **To State citizens and political subdivisions:**
      None.

   C. **To independently owned businesses:**
      See 3 above.

RULEMAKING NOTICE FILING

STATE OF NEW HAMPSHIRE

DATE September 22, 2010

FROM Thomas S. Burack
Commissioner

AT (OFFICE) DES

SUBJECT Rulemaking Notice

TO Office of Legislative Services
Division of Administrative Rules

Please accept for filing the enclosed Rulemaking Notice for the following rules:

Env-A 2300: Mitigation of Regional Haze

Questions from OLS regarding the Rulemaking Notice should be directed to Gretchen Hamel at 271-3137.

Questions from the public regarding the proposed rules, public hearing, or public comment period should be directed to Karla McManus at 271-6854.

Enclosures

cc: Gretchen Hamel, DES Legal Unit Administrator

ec: K. Allen Brooks, Chief, AGO-Environmental Protection Bureau
Karla McManus, DES ARD Planning and Rules Manager
ARD Distribution list

RULEMAKING NOTICE FORM

Notice Number		Rule Number	Env-A 2300

1. Agency Name & Address:	2. RSA Authority:	RSA 125-C:4, I(a), (b), (k)
	3. Federal Authority:	42 U.S.C. §7491; 40 CFR 51.308
Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	4. Type of Action:	
	Adoption	X
	Amendment	
	Repeal	
	Readoption	
	Readoption w/amendment	

5. Short Title: Mitigation of Regional Haze

6. (a) Summary of what the rule says and the effect of the rule on those regulated:

Regional haze is a visibility impairment caused by the emission of air pollutants from numerous sources located over a wide geographic area. Section 169A of the Clean Air Act (42 U.S.C. §7491) mandates visibility protection for federal Class I federal areas, which include 156 national parks and wilderness areas. Regionally, Class I areas include the Great Gulf and Presidential Range - Dry River Wilderness and Acadia National Park. The proposed rules, Chapter Env-A 2300, Mitigation of Regional Haze, establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired power plants that contribute to regional haze. Subtitle Env-A already contains rules govern haze-causing pollutants, including SO2, NOx, and TSP; the proposed rules would supplement those requirements and make the emission limitations for the 3 named pollutants more stringent for the sources that would be subject to the rules. Specifically, the rules will establish new emission limits for SO2, NOx, and TSP to be effective on July 1, 2013 for any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a cyclone-firing, wet-bottom boiler fueled by coal (or any combination of fuels using coal) or a tangential-firing, dry-bottom boiler fueled by oil or gas (or any combination of oil or gas).

6. (b) Brief description of the groups affected:

The only facilities impacted are owned by Public Service of New Hampshire (PSNH). Individuals, including tourists, whose views of the protected areas are impacted will benefit from the proposed rule.

6. (c) Specific section or sections of state statute or federal statute or regulation which the rule is intended to implement:

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

7. Contact person for copies and questions including requests to accommodate persons with disabilities:

Name:	Karla McManus	Title:	ARD Planning and Rules Manager
Address:	Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	Phone #:	271-6854
		Fax#:	271-1381
		E-mail:	Karla.McManus

The rules also can be viewed in PDF at
http://des.nh.gov/organization/commissioner/legal/rulemaking/index.htm

TTY/TDD Access: Relay NH 1-800-735-2964 or dial 711 (in NH)

8. Deadline for submission of materials in writing or, if practicable for the agency, in the electronic format specified: **Monday, November 8, 2010 at 4:00 p.m.**

☒Fax ☒E-mail ☐Other format (specify):

9. Public hearing scheduled for:

Date and Time: **Thursday, October 28, 2010, 9:30 a.m. - 12:30 p.m.**

Place: **Rooms 111-112-113-114, DES Offices, 29 Hazen Drive, Concord, NH**

10. Fiscal Impact Statement (Prepared by Legislative Budget Assistant): FIS # 10:126 , dated 09/22/10

1. Comparison of the costs of the proposed rule(s) to the existing rule(s):

When compared to the existing rules, the proposed rules may increase costs to independently owned businesses by an indeterminable amount.

2. Cite the Federal mandate. Identify the impact on state funds:

The Clean Air Act, Section 169A (42 USC § 7491) and 40 CFR Part 51, Subpart P Protection of Visibility require the state to develop a program to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory class I federal areas in which impairment results from manmade air pollution. If the proposed rules are not adopted, the State would be out of compliance with federal requirements that could result in the US Environmental Protection agency imposing sanctions, including the loss of federal transportation funding.

3. Cost and benefits of the proposed rule(s):

The Department notes that there are three emission units, all owned by Public Service of New Hampshire (PSNH), that will be subject to these rules. PSNH may experience increased costs to the three emission units, however the Department indicates that two of the three units will be capable of meeting the proposed emission requirements with existing emission controls and with additional controls already under construction to meet state law. The Department further indicates the third emission unit will be able to meet the emission requirements with existing emission controls and reasonable adjustments to the sulfur content of its residual fuel oil and/or to the fuel oil/natural gas ratio used in combustion. The Department has no information on FY 2013 costs to estimate any potential increase in cost.

A. To State general or State special funds:

None

B. To State citizens and political subdivisions:

None

C. To independently owned businesses:

None

11. Statement Relative to Part I, Article 28-a of the N.H. Constitution: The proposed rules do not create, expand, or modify any program or responsibility in such a way as to necessitate additional local expenditures by political subdivisions. The rules thus do not violate Part I, Article 28-a of the New Hampshire Constitution.

RULEMAKING REGISTER

NEW HAMPSHIRE
RULEMAKING REGISTER

OFFICE OF LEGISLATIVE SERVICES
ROOM 219, STATE HOUSE ANNEX
25 CAPITOL STREET
CONCORD, NEW HAMPSHIRE 03301-6312
Tel. (603) 271-3680
Fax (603) 271-7871 Website: www.gencourt.state.nh.us/rules/index.html TDD Access: Relay NH 1-800-735-2964

VOLUME XXX, Number 39, October 1, 2010

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CONTINUED MEETING: **Thursday, October 7, 2010 9:00 a.m.**
Rooms 306/308, Legislative Office Building

REGULAR MEETING: **Thursday, October 21, 2010 9:00 a.m.**
Rooms 306/308, Legislative Office Building

JLCAR MEETING DATES AND RELATED FILING DEADLINES OCTOBER-DECEMBER, 2010

The JLCAR has voted to hold its regularly scheduled monthly meetings for October through December, 2010 on the third Thursdays listed below. The minimum 14-day "deadline" prior to the regular JLCAR meeting is listed for agencies to file final proposals or proposed interim rules* for placement on the JLCAR agenda pursuant to RSA 541-A:12, I and RSA 541-A:19, V. The JLCAR has also scheduled continued meetings as listed below on select Thursdays to address any items postponed from the prior regular meetings.

*Note: *Register* publication, and notice filing deadlines, will still occur on Fridays, except as noted. RSA 541-A:19, V requires that an agency's interim rulemaking notice, whether in a newspaper or in the *Register*, must be published at least 7 days prior to the JLCAR meeting. Therefore, the deadline for filing a proposed interim rule with a *Register* notice will be earlier as listed below.

*Filing Deadline for Interim Rules w/ *Register* Notice	Regular Meeting Filing Deadline	Regular Meeting Date	Continued Meeting Date
--	--	September 16	October 7
October 1	October 7	October 21	November 4
October 29	November 4	November 18	December 2
November 24 (Wednesday)	December 2	December 16	None

Notice Number	2010-113	Rule Number	Env-A 2300
1. Agency Name & Address:		2. RSA Authority:	RSA 125-C:4, I(a), (b), (k)
		3. Federal Authority:	42 U.S.C. §7491; 40 CFR 51.308
Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095		4. Type of Action:	
		Adoption	X
		Amendment	
		Repeal	
		Readoption	
		Readoption w/amendment	

5. Short Title: Mitigation of Regional Haze

6. (a) Summary of what the rule says and the effect of the rule on those regulated:

Regional haze is a visibility impairment caused by the emission of air pollutants from numerous sources located over a wide geographic area. Section 169A of the Clean Air Act (42 U.S.C. §7491) mandates visibility protection for federal Class I federal areas, which include 156 national parks and wilderness areas. Regionally, Class I areas include the Great Gulf and Presidential Range - Dry River Wilderness and Acadia National Park. The proposed rules, Chapter Env-A 2300, Mitigation of Regional Haze, establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired power plants that contribute to regional haze. Subtitle Env-A already contains rules govern haze-causing pollutants, including SO2, NOx, and TSP; the proposed rules would supplement those requirements and make the emission limitations for the 3 named pollutants more stringent for the sources that would be subject to the rules. Specifically, the rules will establish new emission limits for SO2, NOx, and TSP to be effective on July 1, 2013 for any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a cyclone-firing, wet-bottom boiler fueled by coal (or any combination of fuels using coal) or a tangential-firing, dry-bottom boiler fueled by oil or gas (or any combination of oil or gas).

6. (b) Brief description of the groups affected:

The only facilities impacted are owned by Public Service of New Hampshire (PSNH). Individuals, including tourists, whose views of the protected areas are impacted will benefit from the proposed rule.

6. (c) Specific section or sections of state statute or federal statute or regulation which the rule is intended to implement:

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

7. Contact person for copies and questions including requests to accommodate persons with disabilities:

Name:	Karla McManus	Title:	ARD Planning and Rules Manager
Address:	Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	Phone #: Fax#: E-mail:	271-6854 271-1381 Karla.McManus

The rules also can be viewed in PDF at http://des.nh.gov/organization/commissioner/legal/rulemaking/index.htm

TTY/TDD Access: Relay NH 1-800-735-2964 or dial 711 (in NH)

NN 2010-113 Continued

8. Deadline for submission of materials in writing or, if practicable for the agency, in the electronic format specified: Monday, November 8, 2010 at 4:00 p.m.

☒Fax ☒E-mail ☐Other format (specify):

9. Public hearing scheduled for:

Date and Time: Thursday, October 28, 2010, 9:30 a.m. - 12:30 p.m.

Place: Rooms 111-112-113-114, DES Offices, 29 Hazen Drive, Concord, NH

10. Fiscal Impact Statement (Prepared by Legislative Budget Assistant): FIS # 10:126 , dated 09/22/10

1. Comparison of the costs of the proposed rule(s) to the existing rule(s):
   When compared to the existing rules, the proposed rules may increase costs to independently owned businesses by an indeterminable amount.

2. Cite the Federal mandate. Identify the impact on state funds:
   The Clean Air Act, Section 169A (42 USC § 7491) and 40 CFR Part 51, Subpart P Protection of Visibility require the state to develop a program to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory class I federal areas in which impairment results from manmade air pollution. If the proposed rules are not adopted, the State would be out of compliance with federal requirements that could result in the US Environmental Protection agency imposing sanctions, including the loss of federal transportation funding.

3. Cost and benefits of the proposed rule(s):
   The Department notes that there are three emission units, all owned by Public Service of New Hampshire (PSNH), that will be subject to these rules. PSNH may experience increased costs to the three emission units, however the Department indicates that two of the three units will be capable of meeting the proposed emission requirements with existing emission controls and with additional controls already under construction to meet state law. The Department further indicates the third emission unit will be able to meet the emission requirements with existing emission controls and reasonable adjustments to the sulfur content of its residual fuel oil and/or to the fuel oil/natural gas ratio used in combustion. The Department has no information on FY 2013 costs to estimate any potential increase in cost.

   A. To State general or State special funds:
      None

   B. To State citizens and political subdivisions:
      None

   C. To independently owned businesses:
      None

11. Statement Relative to Part I, Article 28-a of the N.H. Constitution: The proposed rules do not create, expand, or modify any program or responsibility in such a way as to necessitate additional local expenditures by political subdivisions. The rules thus do not violate Part I, Article 28-a of the New Hampshire Constitution.

NEW HAMPSHIRE
RULEMAKING REGISTER

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VOLUME XXX, Number 45, November 12, 2010

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REGULAR MEETING: **Thursday, November 18, 2010** 9:00 a.m.
Rooms 306/308, Legislative Office Building

CONTINUED MEETING: ****Thursday, December 2, 2010** 9:00 a.m.
Rooms 306/308, Legislative Office Building
*****Consensus of JLCAR members is to cancel this meeting.***

THANKSGIVING HOLIDAYS

Publication of November 24, 2010 Rulemaking Register

Thursday, November 25 and Friday, November 26 are state holidays. The Register that week will be published on Wednesday, November 24.

Deadline for December 3, 2010 Rulemaking Register

The deadline for filing rulemaking notices to be published in the December 3 Register will be the end of work day Wednesday, November 24.

EXTENSION OF PUBLIC COMMENT DEADLINE

Notice Number 2010-113 Rule Number Env-A 2300

1. Agency Name & Address: Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	2. RSA Authority: RSA 125-C:4, I(a), (b), (k) 3. Federal Authority: 42 U.S.C. §7491; 40 CFR 51.308 4. Type of Action: Adoption X Amendment ____ Repeal ____ Readoption ____ Readoption w/amendment ____

5. Short Title: Mitigation of Regional Haze

6. In accordance with RSA 541-A:11, III, the public comment deadline for this proposed rule has been extended past its scheduled date for which notice appeared in the Rulemaking Register on **October 1, 2010** under Notice Number **2010-113**.

7. New deadline for submission of materials in writing or, if practicable for the agency, in the electronic format specified: **Monday, November 22, 2010 at 4:00 p.m.**

☒Fax ☒E-mail ☐Other format (specify):

8. Contact person for copies and questions including requests to accommodate persons with disabilities:

Name:	Karla McManus	Title:	ARD Planning and Rules Manager
Address:	Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	Phone #:	271-6854
		Fax#:	271-1381
		E-mail:	Karla.McManus@des.nh.gov

The rules also can be viewed in PDF at http://des.nh.gov/organization/commissioner/legal/rulemaking/index.htm

TTY/TDD Access: Relay NH 1-800-735-2964 or dial 711 (in NH)

ANNOTATIONS TO INITIAL PROPOSAL FROM THE OFFICE OF LEGISLATIVE SERVICES

SEP 23 2010 11/8

MA

Consent Edit.

RULEMAKING NOTICE FORM

Notice Number 2010-113 | Rule Number Env-A 2300

1. Agency Name & Address:

Department of Environmental Services
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095

2. RSA Authority: RSA 125-C:4, I(a), (b), (k)

3. Federal Authority: 42 U.S.C. §7491; 40 CFR 51.308

4. Type of Action:
Adoption X
Amendment ____
Repeal ____
Readoption ____
Readoption w/amendment ____

5. Short Title: Mitigation of Regional Haze

6. (a) Summary of what the rule says and the effect of the rule on those regulated:

Regional haze is a visibility impairment caused by the emission of air pollutants from numerous sources located over a wide geographic area. Section 169A of the Clean Air Act (42 U.S.C. §7491) mandates visibility protection for federal Class I federal areas, which include 156 national parks and wilderness areas. Regionally, Class I areas include the Great Gulf and Presidential Range - Dry River Wilderness and Acadia National Park. The proposed rules, Chapter Env-A 2300, Mitigation of Regional Haze, establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired power plants that contribute to regional haze. Subtitle Env-A already contains rules govern haze-causing pollutants, including SO2, NOx, and TSP; the proposed rules would supplement those requirements and make the emission limitations for the 3 named pollutants more stringent for the sources that would be subject to the rules. Specifically, the rules will establish new emission limits for SO2, NOx, and TSP to be effective on July 1, 2013 for any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a cyclone-firing, wet-bottom boiler fueled by coal (or any combination of fuels using coal) or a tangential-firing, dry-bottom boiler fueled by oil or gas (or any combination of oil or gas).

6. (b) Brief description of the groups affected:

The only facilities impacted are owned by Public Service of New Hampshire (PSNH). Individuals, including tourists, whose views of the protected areas are impacted will benefit from the proposed rule.

6. (c) Specific section or sections of state statute or federal statute or regulation which the rule is intended to implement:

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

7. Contact person for copies and questions including requests to accommodate persons with disabilities:

Name: Karla McManus | Title: ARD Planning and Rules Manager

Address: Department of Environmental Services
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095

Phone #: 271-6854
Fax#: 271-1381
E-mail: Karla.McManus

The rules also can be viewed in PDF at
http://des.nh.gov/organization/commissioner/legal/rulemaking/index.htm

TTY/TDD Access: Relay NH 1-800-735-2964 or dial 711 (in NH)

8. Deadline for submission of materials in writing or, if practicable for the agency, in the electronic format specified: **Monday, November 8, 2010 at 4:00 p.m.**

☒Fax ☒E-mail ☐Other format (specify):

9. Public hearing scheduled for:

Date and Time: **Thursday, October 28, 2010, 9:30 a.m. - 12:30 p.m.**

Place: **Rooms 111-112-113-114, DES Offices, 29 Hazen Drive, Concord, NH**

10. Fiscal Impact Statement (Prepared by Legislative Budget Assistant): FIS # 10:126 , dated 09/22/10

1. Comparison of the costs of the proposed rule(s) to the existing rule(s):

When compared to the existing rules, the proposed rules may increase costs to independently owned businesses by an indeterminable amount.

2. Cite the Federal mandate. Identify the impact on state funds:

The Clean Air Act, Section 169A (42 USC § 7491) and 40 CFR Part 51, Subpart P Protection of Visibility require the state to develop a program to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory class I federal areas in which impairment results from manmade air pollution. If the proposed rules are not adopted, the State would be out of compliance with federal requirements that could result in the US Environmental Protection agency imposing sanctions, including the loss of federal transportation funding.

3. Cost and benefits of the proposed rule(s):

The Department notes that there are three emission units, all owned by Public Service of New Hampshire (PSNH), that will be subject to these rules. PSNH may experience increased costs to the three emission units, however the Department indicates that two of the three units will be capable of meeting the proposed emission requirements with existing emission controls and with additional controls already under construction to meet state law. The Department further indicates the third emission unit will be able to meet the emission requirements with existing emission controls and reasonable adjustments to the sulfur content of its residual fuel oil and/or to the fuel oil/natural gas ratio used in combustion. The Department has no information on FY 2013 costs to estimate any potential increase in cost.

A. To State general or State special funds:

None

B. To State citizens and political subdivisions:

None

C. To independently owned businesses:

None

11. Statement Relative to Part I, Article 28-a of the N.H. Constitution: The proposed rules do not create, expand, or modify any program or responsibility in such a way as to necessitate additional local expenditures by political subdivisions. The rules thus do not violate Part I, Article 28-a of the New Hampshire Constitution.

Edit. Delete.

Adopt CHAPTER Env-A 2300 to read as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

Env-A 2301.03 Definitions.

(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

(h) "Total suspended particulate matter (TSP)" means particulate matter as measured by the high-volume method described in Appendix B of 40 CFR Part 50.

(i) "Visibility impairment" means "visibility impairment" as defined in 40 CFR 51.301, namely "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

PART Env-A 2302 EMISSION STANDARDS FOR MITIGATION OF REGIONAL HAZE

Env-A 2302.01 Emission Standards Applicable to Cyclone-Firing, Wet-Bottom Boilers.

(a) For any cyclone-firing, wet-bottom boiler subject to this chapter whose maximum heat input rate is less than or equal to 3,000 million BTUs per hour, the following emission rates shall apply:

(1) SO_2 emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600;

(2) NOx emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600; and

(3) Beginning on July 1, 2013, TSP emissions shall not exceed 0.08 lb per million BTUs, demonstrated by completion of periodic stack tests as specified in Env-A 2304.01(b) on the outlet side of the final emission control device.

(b) For any cyclone-firing, wet-bottom boiler subject to this chapter whose maximum heat input rate is greater than 3,000 million BTUs per hour, the following emission rates shall apply:

(1) SO_2 emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600;

(2) Beginning on July 1, 2013, NOx emissions shall not exceed 0.37 lb per million BTUs on a calendar monthly average basis as recorded by a continuous emissions monitoring system (CEMS) as specified in Env-A 2303; and

(3) Beginning on July 1, 2013, TSP emissions shall not exceed 0.08 lb per million BTUs, demonstrated by completion of periodic stack tests as specified in Env-A 2304.01(b)on the outlet side of the final emission control device.

Env-A 2302.02 Emission Standards Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, the following emission rates shall apply:

(a) Beginning on July 1, 2013, SO_2 emissions shall not exceed 0.50 pound (lb) per million BTUs on a calendar monthly average basis as recorded by a CEMS as specified in Env-A 2303;

(b) NOx emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600; and

(c) TSP emissions shall not exceed limitations specified in permit conditions established in accordance with Env-A 600.

PART Env-A 2303 CONTINUOUS EMISSIONS MONITORING SYSTEMS

Env-A 2303.01 Requirements for Continuous Emissions Monitoring Systems. The owner or operator of a source whose emissions are required to be monitored and recorded by a CEMS as provided in Env-A 2302.01 or Env-A 2302.02 shall:

(a) Install, calibrate, operate, maintain, and perform quality assurance testing of the CEMS in accordance with Env-A 808; and

(b) Comply with recordkeeping requirements for CEMS specified in Env-A 903.04.

PART Env-A 2304 PERFORMANCE TESTING

Env-A 2304.01 Performance Testing Requirements Applicable to Cyclone-Firing, Wet-Bottom Boilers. For any cyclone-firing, wet-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions and NOx emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Periodic stack tests for TSP emissions shall be conducted in accordance with Env-A 802, subject to the following:

(1) For an initial period of 3 years, stack tests shall be conducted annually, with the first stack test to be completed by June 30, 2013;

(2) Beginning on July 1, 2015, stack tests shall be conducted every other year, with the fourth stack test to be completed by June 30, 2017; and

(3) At any facility where an affected unit shares a common stack with a second affected unit, the stack emissions shall be tested as from one source, by either of the following methods:

a. With both units operating simultaneously, a stack test on the combined emissions from both units, or

b. With one unit operating at a time, separate stack tests on the emissions from each unit.

Env-A 2304.02 Performance Testing Requirements Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions, NOx emissions, and TSP emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Any stack test required to demonstrate compliance with this part shall be conducted in accordance with Env-A 802.

Appendix

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

FINAL PROPOSAL FILING

STATE OF NEW HAMPSHIRE

Thomas S. Burack

FROM Thomas S. Burack DATE December 2, 2010

Commissioner AT (OFFICE) DES

SUBJECT Final Proposal #2010-~~13~~ 113

TO Office of Legislative Services
Division of Administrative Rules

In accordance with RSA 541-A:12, enclosed please find the Final Proposal Cover Sheet and copies of the corresponding rule for the following rules:

Env-A 2300: Mitigation of Regional Haze

If you have any questions, please contact Gretchen Hamel at 271-3137 or Karla McManus at 271-6854.

Enclosures

cc: Gretchen Hamel, DES Legal Unit

ec: Karla McManus, DES ARD

COVER SHEET FOR FINAL PROPOSAL

Notice Number	2010-113	Rule Number	Env-A 2300

1. Agency Name & Address: Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	2. RSA Authority: RSA 125-C:4, I (a), (b), (k) 3. Federal Authority: 42 U.S.C. §7491; 40 CFR 51.308 4. Type of Action: ☒ Adopt ☐ Amendment ☐ Repeal ☐ Readoption ☐ Readoption w/amendment

5. Short Title: Mitigation of Regional Haze

6. Contact person for copies and questions:

Name:	Karla McManus	Title:	ARD Planning and Rules Manager
Address:	Department of Environmental Services 29 Hazen Drive P.O. Box 95 Concord, NH 03302-0095	Phone #:	(603) 271-6854

7. Yes ☐ No ☒ Agency requests Committee legal counsel review and delayed Committee review pursuant to RSA 541-A:12, I-a

8. The rulemaking notice appeared in the Rulemaking Register on **October 1, 2010**

SEE THE INSTRUCTIONS--PLEASE SUBMIT 2 COPIES OF THIS COVER SHEET AND 2 COPIES OF THE FOLLOWING:
(and numbered correspondingly)

9. The "Final Proposal-Fixed Text", including the cross-reference table required by RSA 541-A:3-a, II as an appendix.

10. The full text of the RSA passage granting rulemaking authority.

11. Yes ☐ N/A ☒ Incorporation by Reference Statement(s) because this rule incorporates a document by reference for which an Incorporation by Reference Statement is required pursuant to RSA 541-A:12, III.

12. Yes ☒ N/A ☐ The "Final Proposal-Annotated Text" indicating how the proposed rule was changed because the text of the rule changed from the Initial Proposal pursuant to RSA 541-A:12, II(e).

13. Yes ☐ N/A ☒ The amended fiscal impact statement because the change to the text of the Initial Proposal affects the original fiscal impact statement (FIS) pursuant to RSA 541-A:5, VI.

Adopt CHAPTER Env-A 2300 to read as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

Env-A 2301.03 Definitions.

(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

(h) "Total suspended particulate matter (TSP)" means particulate matter as measured by the high-volume method described in Appendix B of 40 CFR Part 50.

(i) "Visibility impairment" means "visibility impairment" as defined in 40 CFR 51.301, namely "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

PART Env-A 2304 PERFORMANCE TESTING

Env-A 2304.01 Performance Testing Requirements Applicable to Cyclone-Firing, Wet-Bottom Boilers. For any cyclone-firing, wet-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions and NOx emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Periodic stack tests for TSP emissions shall be conducted in accordance with Env-A 802, subject to the following:

(1) For an initial period of 3 years, stack tests shall be conducted annually, with the first stack test to be completed by June 30, 2013;

(2) Beginning on July 1, 2015, stack tests shall be conducted every other year, with the fourth stack test to be completed by June 30, 2017; and

(3) At any facility where an affected unit shares a common stack with a second affected unit, the stack emissions shall be tested as from one source, by either of the following methods:

a. With both units operating simultaneously, a stack test on the combined emissions from both units, or

b. With one unit operating at a time, separate stack tests on the emissions from each unit.

Env-A 2304.02 Performance Testing Requirements Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions, NOx emissions, and TSP emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Any stack test required to demonstrate compliance with this part shall be conducted in accordance with Env-A 802.

Appendix

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

Adopt CHAPTER Env-A 2300 to read as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

Env-A 2301.03 Definitions.

(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

(h) "Total suspended particulate matter (TSP)" means particulate matter as measured by the high-volume method described in Appendix B of 40 CFR Part 50.

(i) "Visibility impairment" means "visibility impairment" as defined in 40 CFR 51.301, namely "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

PART Env-A 2304 PERFORMANCE TESTING

Env-A 2304.01 Performance Testing Requirements Applicable to Cyclone-Firing, Wet-Bottom Boilers. For any cyclone-firing, wet-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions and NOx emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Periodic stack tests for TSP emissions shall be conducted in accordance with Env-A 802, subject to the following:

(1) For an initial period of 3 years, stack tests shall be conducted annually, with the first stack test to be completed by June 30, 2013;

(2) Beginning on July 1, 2015, stack tests shall be conducted every other year, with the fourth stack test to be completed by June 30, 2017; and

(3) At any facility where an affected unit shares a common stack with a second affected unit, the stack emissions shall be tested as from one source, by either of the following methods:

a. With both units operating simultaneously, a stack test on the combined emissions from both units, or

b. With one unit operating at a time, separate stack tests on the emissions from each unit.

Env-A 2304.02 Performance Testing Requirements Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions, NOx emissions, and TSP emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Any stack test required to demonstrate compliance with this part shall be conducted in accordance with Env-A 802.

Appendix

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

ADOPTED RULE

Adopt CHAPTER Env-A 2300 to read as follows:

CHAPTER Env-A 2300 MITIGATION OF REGIONAL HAZE

Statutory Authority: RSA 125-C:4, I(a), (b), (k)

PART Env-A 2301 PURPOSE; APPLICABILITY; DEFINITIONS

Env-A 2301.01 Purpose. The purpose of this chapter is to establish emission standards for sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) at certain fossil-fuel-fired steam generating units in order to reduce emissions that contribute to regional haze. These rules are necessary to ensure compliance with §169A of the Act and regional haze program requirements established at 40 CFR 51.308, including but not limited to the provisions for Best Available Retrofit Technology (BART).

Env-A 2301.02 Applicability. This chapter shall apply to any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a:

(a) Cyclone-firing, wet-bottom boiler fueled by coal or any combination of fuels using coal; or

(b) Tangential-firing, dry-bottom boiler fueled by oil or gas or any combination of oil or gas.

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(a) "Best Available Retrofit Technology (BART)" means "best available retrofit technology" as defined in 40 CFR 51.301, namely "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

(b) "Coal" means "coal" as defined in Env-A 1211.02.

(c) "Gas" means "gas or gaseous fuel" as defined in Env-A 1211.02.

(d) "Maximum heat input rate" means "maximum heat input rate" as defined in Env-A 1211.02.

(e) "Oil" means any petroleum-based liquid fuel oil, including distillate and residual fuel oils.

(f) "Regional haze" means "regional haze" as defined in 40 CFR 51.301, namely "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."

(g) "Stack test" means the sampling, analysis, and reporting of emissions from a stationary point source in accordance with testing procedures specified in Env-A 802.

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PART Env-A 2304 PERFORMANCE TESTING

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(a) Performance testing for SO_2 emissions and NOx emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Periodic stack tests for TSP emissions shall be conducted in accordance with Env-A 802, subject to the following:

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(2) Beginning on July 1, 2015, stack tests shall be conducted every other year, with the fourth stack test to be completed by June 30, 2017; and

(3) At any facility where an affected unit shares a common stack with a second affected unit, the stack emissions shall be tested as from one source, by either of the following methods:

a. With both units operating simultaneously, a stack test on the combined emissions from both units, or

b. With one unit operating at a time, separate stack tests on the emissions from each unit.

Env-A 2304.02 Performance Testing Requirements Applicable to Tangential-Firing, Dry-Bottom Boilers. For any tangential-firing, dry-bottom boiler subject to this chapter, performance tests shall be conducted as follows:

(a) Performance testing for SO_2 emissions, NOx emissions, and TSP emissions shall meet the requirements specified in permit conditions established in accordance with Env-A 600; and

(b) Any stack test required to demonstrate compliance with this part shall be conducted in accordance with Env-A 802.

Appendix

Rule Section(s)	State Statute(s) Implemented	Federal Statute(s) Implemented
Env-A 2300	RSA 125-C:4, I(a), (b), (k)	42 U.S.C. §7491, 40 CFR §51.308

APPROVAL OF THE RULE BY THE JOINT LEGISLATIVE COMMITTEE ON ADMINISTRATIVE RULES

CAROL J. HOLAHAN
DIRECTOR

STATE OF NEW HAMPSHIRE

OFFICE OF LEGISLATIVE SERVICES

STATE HOUSE
107 NORTH MAIN STREET, ROOM 109
CONCORD, NEW HAMPSHIRE 03301-4951

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January 10, 2010

Received from Commissioner, Department of Environmental Services

the following certified rule(s) filed with the Director of Legislative Services, in accordance with RSA 541-A, the Administrative Procedures Act.

Document #	#9846
Relative to:	Env-A 2300 - Mitigation of Regional Haze.
Number of Pages:	3
Adopted Date:	01-07-11
Filing Date:	01-07-11
Effective Date:	01/08/2011
Expiration Date:	01/08/2019
Notes:	N/A

In all communications with this office concerning the above rule(s), please cite the appropriate document number, as indicated above.

Carol J. Holahan, Director
Office of Legislative Services

TDD Access: Relay NH 1-800-735-2964
DIRECTOR (603) 271-3432
LEGAL STAFF (603) 271-3435
FAX: (603) 271-6607
RESEARCH (603) 271-3326
ADMINISTRATIVE RULES (603) 271-3680

ATTACHMENT HH

Title V Operating Permit for PSNH Merrimack Station (Proposed)

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Title V Operating Permit

Permit No: **TV-0055**
Date Issued: **March 15, 2010**

Proposed

This certifies that:
Northeast Utilities
Public Service of New Hampshire
780 North Commercial Street
Manchester, NH 03101

has been granted a Title V Operating Permit for the following facility and location:
Public Service of New Hampshire
Merrimack Station
97 River Rd.
Bow, NH 03304-3314
Facility ID No: **3301300026**
ORIS Code: **2364**
Application No: **FY96-TV048**, received on July 1, 1996, Original Title V Operating Permit application

This Title V Operating Permit is hereby issued under the terms and conditions specified in the Title V application referenced above filed with the New Hampshire Department of Environmental Services under the signature of the following responsible official certifying to the best of their knowledge that the statements and information therein are true, accurate and complete.

Responsible Official:
John MacDonald (603) 634-2236

Technical Contact:
Laurel Brown (603) 634-2331

Designated Representative:
John MacDonald (603) 634-2236
Alternate Designated Representative:
William Smagula (603) 634-2851
Authorized Account Representative:
John MacDonald (603) 634-2236
Alternate Authorized Account Representative:
William Smagula (603) 634-2851

This Permit is issued by the New Hampshire Department of Environmental Services, Air Resources Division pursuant to its authority under New Hampshire RSA 125-C, D, J, and O, and in accordance with the provisions of the Code of Federal Regulations, Title 40, Part 70.

This Permit is effective upon issuance and expires on **xxxx.**

____
Director, Air Resources Division

TABLE OF CONTENTS

ABBREVIATIONS

AAL	Ambient Air Limit
AEL	Alternative Emission Limit
AP-42	Compilation of Air Pollutant Emission Factors
ARD	Air Resources Division
ASTM	American Society for Testing and Materials
ATS	Allowance Tracking System
BACT	Best Available Control Technology
BHP (or bhp)	Brake Horse Power
BTU	British Thermal Units
CAA	Clean Air Act, 42 U.S.C. § 7401, et seq.
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstracts Service
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DER	Discrete Emission Reduction
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
Env-Wm	New Hampshire Code of Administrative Rules – Waste Management Division
ECS	Emission Control System
ERC	Emission Reduction Credit
ETS	Emissions Tracking System
FR	Federal Register
gal/hr	Gallons per hour
HAP	Hazardous Air Pollutant
HHV	High Heat Value
HCl	Hydrochloric acid
hr	Hour
kscfm	1,000 standard cubic feet per minute
kGal	1,000 gallons
KVDC	Kilovolt Direct Current
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb/hr	Pounds per hour
LNB	Low NO_x Burner
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas (Propane)
MACT	Maximum Achievable Control Technology
mg/L	Milligrams per liter
mmBtu	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt
NAAQS	National Ambient Air Quality Standard

ABBREVIATIONS (cont.)

NATS	NOx Allowance Tracking System
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NG	Natural Gas
NHDES (or DES)	New Hampshire Department of Environmental Services
NMOC	Non-Methane Organic Compound
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PCB	Polychlorinated biphenyls
PE	Potential Emission
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmdv	part per million by dry volume
PSD	Prevention of Significant Deterioration
PSI	Pounds per Square Inch
PTE	Potential to Emit
PUC	Public Utilities Commission
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
T-12M	Tons during any consecutive 12-month period
TAP	Toxic Air Pollutant
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
USEPA	United States Environmental Protection Agency
VER	Voluntary Emission Reduction
VOC	Volatile Organic Compound

Facility Specific Title V Operating Permit Conditions

I. Facility Description of Operations

PSNH - Merrimack Station is a fossil fuel-fired electricity generating facility, owned and operated by Public Service of New Hampshire (PSNH), a subsidiary of Northeast Utilities. The facility is comprised of two utility boilers, two combustion turbines operating as load shaving units, an emergency generator, an emergency boiler, and primary and secondary coal crushers. The facility operations also include various activities that are classified as insignificant or exempt activities.

The two utility boilers (MK1 and MK2) primarily burn bituminous coal; the two combustion turbines primarily burn No. 1 fuel oil or JP-4; the emergency generator burns No. 2 fuel oil or diesel fuel, and the emergency boiler burns No. 2 fuel oil or low sulfur diesel fuel. PSNH – Merrimack Station ignites the two utility boilers with No. 2 fuel oil.

Each utility boiler stack is equipped with continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS). PSNH – Merrimack Station emits NOx, SO_2, CO, VOCs, PM, CO_2, RTAPs, and HAPs. PSNH – Merrimack Station has installed control equipment and implemented operational changes to reduce emissions, including selective catalytic reduction (SCR) systems to control NOx emissions, and electrostatic precipitators (ESP) to control PM emissions.

PSNH – Merrimack Station operates a fly ash re-injection system in each of the two Boilers. Flyash is reinjected from the ash hoppers into the cyclone boilers for up to 24 hours per day and each day of the year. This is considered normal operation of the flyash injection system.[1]

II. Permitted Activities

In accordance with all of the applicable requirements identified in this permit, the Permittee is authorized to operate the devices and or processes identified in Sections III, IV, V and VI within the terms and conditions specified in this Permit.

III. Significant Activities Identification and Stack Criteria

A. Significant Activity Identification

The activities identified in the following table (Table 1) are subject to and regulated by this Title V Operating Permit:

[1] Particulate matter emissions from the boiler are generally lower when flyash is not reinjected into the boiler.

Table 1 Significant Activity Identification			
Emission Unit Number	Description of Emission Unit	Maximum Gross Heat Input Rate or Maximum Power Output	Maximum Operating Conditions
MK1	Steam Generating Unit 1 (Installed in 1960) Front wall firing	Bituminous Coal: 1,238 mmBtu/hr	A) Maximum fuel consumption rate of bituminous coal shall be limited to 48.5 tons/hr, not to exceed 425,289 tons during any consecutive 12-month period[2] B) No. 2 fuel oil consumption shall not exceed 14.5 million gallons during any consecutive 12 month period.
MK2	Steam Generating Unit 2 (Installed in 1968) Opposed wall firing	Bituminous Coal: 3,473 mmBtu/hr	A) Maximum fuel consumption rate of bituminous coal shall be limited to 136.2 tons/hr, not to exceed 1,193,078 tons during any consecutive 12-month period[3]. B) No. 2 fuel oil consumption shall not exceed 14.5 million gallons during any consecutive 12 month period.
MKCT1	Combustion Turbine #1 (Installed in 1968) One-end only firing	No. 1 fuel oil or JP-4: 319 mmBtu/hr	Maximum fuel consumption rate shall not exceed 2,279 gal/hr[4] .
MKCT2	Combustion Turbine #2 (Installed in 1969) One-end only firing	No. 1 fuel oil or JP-4: 319 mmBtu/hr	Maximum fuel consumption rate shall not exceed 2,279 gal/hr[5] .
MKPCC	Primary Coal Crusher System consisting of two crushers that operate in parallel (Installed in 1960)	NA	Maximum operating rate of MKPCC shall be limited to 885 ton/hr coal.
MKSCC	Secondary Coal Crusher System consisting of two crushing systems employing two crushers (for a total of four	NA	Maximum operating rate of MKSCC shall be limited to 690 ton/hr coal.

[2] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[3] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[4] The heating value of JP-4 and No. 1 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[5] The heating value of JP-4 and No. 1 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

Table 1 Significant Activity Identification			
Emission Unit Number	Description of Emission Unit	Maximum Gross Heat Input Rate or Maximum Power Output	Maximum Operating Conditions
	crushers) operating in parallel (Installed in 1960)		
MKEG	Emergency Generator (Installed in 1988)	Diesel fuel or No. 2 fuel oil: 3.93 mmBtu/hr	A) Maximum fuel consumption rate of diesel fuel shall not exceed 28.7 gal/hr.[6] B) Maximum fuel consumption rate of No. 2 fuel oil shall not exceed 28.1 gal/hr.[7]
MKEB	Emergency Boiler (Temporary – Each installation)	No. 2 fuel oil (with a maximum sulfur content of 0.4% by weight), or on-road low sulfur diesel oil (with a maximum sulfur content of 0.05% by weight): 96 mmBtu/hr	A) Maximum fuel consumption rate of No. 2 fuel oil shall not exceed 520 gal/hr and 11,760 gal/day[8]; or B) Maximum fuel consumption rate of on-road low sulfur diesel oil shall not exceed 701 gal/hr

B. Stack Criteria

A. The following devices at the Facility shall have exhaust stacks that discharge vertically, without obstruction, and meet the criteria in Table 2:

Table 2 – Stack Criteria				
Stack Number	Emission Unit Number	Emission Unit Description	Minimum Stack Height (Feet) Above Ground Level	Maximum Inside Stack Diameter (Feet)
STMK1	MK1	Steam Generating Unit No. 1	225	8.6
STMK2	MK2	Steam Generating Unit No. 2	317	14.5
STMKCT1	MKCT1	Combustion Turbine #1	20	10.5 x 14
STMKCT2	MKCT2	Combustion Turbine #2	20	10.5 x 14
STMKEG	MKEG	Emergency Generator	12	0.5
STMKEB	MKEB	Emergency Boiler	22.33	4.0

[6] The heating value of the fuel is assumed to be 137,000 Btu/gal. The fuel consumption rates vary based on the actual heat content of the fuel burned.

[7] The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[8] The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

B. Stack criteria described in Table 2 may be changed without prior approval from the Division provided that:
   1. An air quality impact analysis is performed either by the facility or the Division (if requested by the facility in writing) in accordance with Env-A 606, Air Pollution Dispersion Modeling Impact Analysis Requirements, and the "Guidance and Procedure for Performing Air Quality Impact Modeling in New Hampshire," and
   2. The analysis demonstrates that emissions from the modified stack will continue to comply with all applicable emission limitations and ambient air limits.

C. All air modeling data and analyses shall be kept on file at the facility for review by the Division upon request.

D. The Owner or Operator shall provide written notification to the Division of the stack change within 15 days after making the change. Such notification shall include:
   1. A description of the change; and
   2. The date on which the change occurred.

IV. Insignificant Activities Identification

All activities at this facility that meet the criteria identified in Env-A 609.04(d), shall be considered insignificant activities. Emissions from the insignificant activities shall be included in the total facility emissions for the emission-based fee calculation described in Section XXIII. of this Permit.

V. Exempt Activities Identification

All activities identified in Env-A 609.03(c) shall be considered exempt activities and shall not be included in the total facility emissions for the emission based fee calculation described in Section XXIII of this permit.

VI. Pollution Control Equipment/Method Identification

The devices and/or processes identified in Table 3 are considered pollution control equipment or techniques for each identified emissions unit:

Table 3 – Pollution Control Equipment/Method Identification		
Pollution Control Equipment Number	Description of Equipment/Method	Emission Unit Number
MK1-PC1	Electrostatic Precipitator (ESP) #1 on MK1	MK1
MK1-PC2	ESP #2 on MK1	MK1
MK1-PC3	Selective Catalytic Reduction (SCR) System	MK1
MK2-PC4	ESP #1 on MK2	MK2
MK2-PC5	ESP #2 on MK2	MK2
MK2-PC6	SCR System	MK2

VII. Alternative Operating Scenarios

While operating under an alternative operating scenario, the Permittee shall comply with all applicable requirements specified in this permit, including but not limited to, state and federal operational and emission limitations specified in Section VIII.A and H, monitoring, and testing requirements specified in Section VIII. I, recordkeeping requirements specified in Section VIII. J and reporting requirements specified in Section VIII.K. Pursuant to 40 CFR 70.6 (a)(9), the Permittee shall keep all applicable records pertaining to the alternative operating scenario during such operation. The Permittee shall keep a record of the scenario under which it is operating.

A. Trial Test Burns with Other Fuels (Temporary Permits FP-T-0054 & TP-B-0462)

Prior to the use of any fuel other than bituminous coal, No. 2 fuel oil or other fuels previously reviewed and approved by DES, PSNH – Merrimack Station shall submit a proposal to DES, which shall include, but not be limited to the following:

1. Type of fuel;
2. Analysis data of the fuel proposed, which shall include proximate and ultimate analysis, volatile and semi-volatile analyses (i.e., EPA Method 8240, 8250, 8260, or 8270) and metals analysis (i.e., Method 3050 and mercury).
3. Specification of baseline operating conditions at PSNH - Merrimack Station including coal feed rate, percent moisture of coal feed, oil firing rate, ESP and SCR operating conditions, and emissions values of SO_2, NOx, particulate matter (TSP and PM_{10}, if available), CO (if available), and opacity;
4. A comprehensive test plan, which shall present the proposed operating conditions for the trial burn, to include but not be limited to the following:
   a) Length of fuel trial;
   b) New fuel rate;
   c) Means of measuring new fuel feed rate;
   d) Description of new fuel feed process;
   e) New fuel preparations prior to burning;
   f) Percent moisture of new fuel feed;
   g) Time table for operation stability;
   h) Coal feed rate;
   i) Coal percent moisture;

j) ESP and SCR operating conditions;

k) Expected emission values of opacity, SO_2, NOx , particulate matter (TSP and PM_{10}, if available), and CO;

l) The test plan shall also address the continuous tracking or operational data prior to the fuel trial, during the fuel trial, and for a short time after the fuel trial. SO_2, NOx, and opacity can be monitored using the existing CEMs.

m) A compliance stack test protocol for TSP emissions using US EPA Methods 1 through 4, Method 5, Method 17, or a DES approved alternative, when requested by DES.

n) Operational parameters to be monitored and recorded, which shall include, but not be limited to steam flows, boiler temperatures, ammonia flow, and oxygen;

o) The effects of the new fuel on flyash characteristics and resulting effect on the ESP and SCR operations;

p) The effects of the new fuel on bottom ash characteristics;

q) Specification and description of expected operational and combustion conditions when the trial burn has reached stable conditions with the new fuel feed; and

r) A timetable or schedule with approximate dates of the trial test burn.

5. Based on information regarding the proposed trial fuel burn provided by PSNH – Merrimack Station, the DES may request additional specific information on the proposed trial burn operations. In addition, metal emission stack testing may be required dependent upon DES review of the new fuel metal analysis.

6. If the new fuel is to be consumed on a regular basis, PSNH – Merrimack Station shall apply for a Temporary Permit or apply for an amendment to this Title V Operating Permit, as determined by DES. If the new fuel results in a major modification, NSR or PSD program requirements may apply, as well as a public notice, and comment period.

7. DES shall respond within 30 days of receipt of a proposal with approval, conditional approval, denial, or request for additional information.

8. DES Waste Management Division may have additional requirements and concerns and shall be contacted by PSNH – Merrimack Station prior to the initiation of any trial burn, if applicable.

9. A summary report shall be submitted to DES within 60 days after the end of the trial fuel burn, which should include a summary of operational results and trends, emission values to include CEM and stack test data, and proposed future use of the trial fuel.

B. Fly Ash Re-injection (Temporary Permit Nos. FP-T-0054, TP-B-0462):

Fly ash has historically been, and is currently re-injected at PSNH – Merrimack Station as part of normal operation. As necessary, based on operational and/or technical drivers, including available options for storage and beneficial reuse, PSNH – Merrimack Station is authorized to cease fly ash re-injection, as an alternative operating scenario.

C. Early Mercury Emission Reduction Methods (RSA 125-O:13) (State Enforceable Only):

Prior to July 1, 2013, PSNH is authorized to test and implement mercury reduction control technologies or methods, including sorbent injection, to achieve early reductions in mercury emissions below the baseline mercury emissions, as an alternative operating scenario. Prior to any testing, PSNH shall submit a trial plan to DES for review and approval. The plan must contain, at a minimum, the following information:

1. Description of the early mercury emission reduction control methodology.

2. Expected values of mercury, SO_2, and TSP emissions, and opacity.

3. Compliance stack test protocol in accordance with Env-A 800 for TSP emissions testing using Method 1 through 4, Method 5, or a DES approved alternative or other pollutant testing, when requested by DES. If this testing is also to demonstrate the effectiveness of the mercury reduction method and amount of reduction, then compliance testing for mercury shall be conducted using a DES approved method.

4. The effects of the methodology on fly ash characteristics, bottom ash characteristics, and ESP operation.

5. Based on information regarding the proposed trial mercury emission reduction methodology, DES may request additional specific information on the proposed methodology.

6. If the new methodology is to be used on a regular basis, PSNH must submit the necessary information for a permit application, as applicable.

7. A summary report shall be submitted to DES within 60 days after stack testing is completed. The report shall include a summary of operational results and trends, emissions values including CEM, COM, and stack test data, and proposed future use of the methodology.

VIII. Applicable Requirements

A. State-only Enforceable Operational and Emission Limitations

The Permittee shall be subject to the state-only operational and emission limitations identified in Table 4 below.

Table 4 – State-Only Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
1.	Env-A 1403	All devices subject to RSA 125-I and Env-A 1400	All devices or processes, subject to RSA 125-I and Env-A 1400, shall comply with Env-A 1400 *(Regulated Toxic Air Pollutants).*
2.	Env-A 1403.01(d)	All devices subject to RSA 125-I and Env-A 1400	Documentation for the demonstration of compliance shall be retained at the facility and shall be made available to DES for inspection upon request.
3.	Env-A 1404.01	All devices subject to RSA 125-I and Env-A 1400	A) The owner of a new or modified device or process requiring a permit under this chapter shall submit an application for a temporary permit in accordance with Env-A 607.03. B) Pursuant to RSA 125-I:5,I, the owner shall not operate the device or process until a temporary permit is issued.
4.	Env-A 1405.01	All devices subject to RSA 125-I and Env-A 1400	The owner of any device or process that emits an RTAP shall determine compliance with the AAL by using one of the methods provided in Env-A 1405. Upon request, the owner of any device or process that emits an RTAP shall provide documentation of compliance with the AAL to DES.
5.	Env-A 1405.02	MK1 & MK2	Ammonia slip stream emissions from the SCR units shall not exceed 10 ppmdv at 3% oxygen (dry basis), as measured at the stack outlet.
6.	Env-A 1002.04 Fugitive Dust	Facility wide	The Permittee shall prevent, abate, and control fugitive dust emissions, including fugitive coal dust using best management practices such as wetting, covering, shielding, or vacuuming.[9]
7.	RSA 125-O:13,I. Compliance	MK1 & MK2	The owner shall install and have operational scrubber technology to control mercury emissions at Merrimack Units 1 and 2 no later than July 1, 2013.
8.	RSA 125-O:13,II. Compliance	Affected sources as defined in RSA 125-O:12, namely MK1, MK2, SR4, & SR6	Beginning on July 1, 2013, total mercury emissions from the affected sources shall be at least 80 percent less on an annual basis than the baseline mercury input, as defined in RSA 125-O:12,III.
9.	RSA 125-O:13,III. Compliance	MK1 & MK2	Prior to July 1, 2013, the owner shall test and implement, as practicable, mercury reduction control technologies or methods to achieve early reductions in mercury emissions below the baseline mercury emissions. The owner shall report the results of any testing to the DES and shall submit a plan for DES approval before commencing implementation of mercury reduction control technologies or methods.

[9] To comply with this provision, PSNH – Merrimack Station shall use Best Management Practices to manage and minimize fugitive coal dust. See the Best Management Practice policies established in the PSNH Generation Environmental Management System Plan for Fugitive Plant Emissions.

Table 4 – State-Only Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
10.	RSA 125-O:13,V. Compliance	MK1 & MK2	Mercury reductions (achieved by the scrubber technology) that are greater than 80 percent, shall be sustained in so far as the proven operational capability of the system, as installed allows. DES in consultation with the owner shall determine the maximum sustainable rate of mercury emission reductions for each of the boilers and incorporate such emission reductions rate as a permit condition of operational permits issued by DES for units MK1 & MK2.
11.	RSA 125-O:13,VI. Compliance	MK1 & MK2	The purchase of mercury emissions allowances or credits from any established emissions allowance or credit program shall not be allowed for compliance with the mercury reduction requirements of RSA 125-O:16,II.
12.	RSA 125-O:13,VII. Compliance	MK1 & MK2	If the mercury reduction requirement of RSA 125-O:13,II. is not achieved in any year after the July 1, 2013 implementation date, and after full operation of the scrubber technology, then the owner may utilize early emissions reduction credits or over-compliance credits, or both, to make up any shortfall, and thereby be in compliance.
13.	RSA 125-O:13,VIII. Compliance	MK1 & MK2	If the mercury reduction requirement of RSA 125-O:13,II. is not achieved in any year after the July 1, 2013 implementation date despite the owner's installation and full operation of scrubber technology, consistent with good operational practice, and the owner's exhaustion of any available early emissions reduction or over-compliance credits, then the owner shall be deemed in violation of this section unless it submits a plan to the DES, within 30 days of such non-compliance, and subsequently obtains approval of that plan for achieving compliance within one year from the date of such non-compliance. The DES may impose conditions for approval of such plan.

Table 4 – State-Only Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
14.	RSA 125-O:16,I. Economic Performance Incentives	MK1 & MK2	A) DES shall issue to the owner early emissions reduction credits in the form of credits or fractions thereof for each pound of mercury or fraction thereof reduced below the baseline mercury emissions, on an annual basis, in the period prior to July 1, 2013. B) Ratios of early reduction credits to pounds of mercury reduced shall be as follows: i) 1.5 credits per pound reduced prior to July 1, 2008; ii) 1.25 credits per pound for reductions between July 1, 2008 and December 31, 2010; and iii) 1.1 credits per pound for reductions between January 1, 2011 and July 1, 2013. C) Reductions shall be calculated based upon the results of stack tests conducted, measurement by continuous emission monitoring, or other methodology approved by the DES to confirm emissions during the time of operation of mercury reduction technology. D) Early emissions reduction credits may be banked by the owner or utilized after July 1, 2013 to meet the reduction requirement of RSA 125-O:13,II. as allowed under RSA 125-O:13,VII. E) Early emissions reduction credits are not sellable or transferable to non-affected sources; however, upon the July 1, 2013 compliance date, the owner may request a one-for-one conversion of early emissions reduction credits to over-compliance credits. F) Should a federal rule applicable to mercury emissions at one or more of the affected sources be enacted with an implementation date prior to July 1, 2013, then early reduction credits may only be earned for emissions reductions that exceed the level required by the federal rule of the affected sources in aggregate or the baseline mercury emissions level, whichever is lower, at the same ratios listed in B), above. G) Early emissions reduction credits shall not be used for compliance with the requirement of RSA 125-O:13,II. prior to the installation of scrubber technology, and shall not be used as a means to delay the installation of the scrubber technology.

Table 4 – State-Only Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
15.	RSA 125-O:16,II. Economic Performance Incentives	MK1 & MK2	A) DES shall issue to the owner over-compliance credits in the form of credits or fractions thereof for each pound of mercury or fraction thereof reduced in excess of the emissions reduction requirement of RSA 125-O:13,II., on an annual basis, following the compliance date of July 1, 2013. B) The ratios of over-compliance credits to excess pounds of mercury reduced shall be as follows: i) 0.5 credits per pound reduced for reductions between 80 and 85 percent; ii) 1 credit per pound reduced for reductions between 85 and 90 percent reduction; and iii) 1.5 credits per pound reduced for reductions of 90 percent or greater. C) Over-compliance credits may be banked for future use. The requirements of RSA 125-O:13,V. shall not alter the emissions levels at which over-compliance credits are earned. D) Should a federal rule applicable to mercury emissions at one or more of the affected sources be enacted, then over-compliance credits may only be earned for emissions reductions that exceed the level required by the federal rule of the affected sources in aggregate or the requirement of RSA 125-O:13,II., whichever is lower, at the same ratios listed in B), above. E) At the request of the owner of an affected source, over-compliance credits may be surrendered by the owner to the DES and SO_2 allowances shall be transferred to the owner at a rate of 55 tons SO_2 allowances for every one over-compliance credit. Transfer shall be limited to a maximum of 20,000 total tons SO_2 allowances transferred in a given year, defined as the sum of all SO_2 allowances received by the affected sources under RSA 125-O:4,IV(a)(2) and IV(a)(3), and under this subparagraph. SO_2 allowances shall be credited to the affected sources' accounts in the following year in accordance with RSA 125-O:4,IV(a)(4).

B. Federally Enforceable Operational and Emission Limitations

1. The Permittee shall be subject to the federally enforceable operational and emission limitations identified in Table 6 below:

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
1.	Temporary Permit FP-T-0054 & Temporary Permit TP-B-0462	MK1 & MK2	No. 2 fuel oil is used to light off fires in MK1 and MK2 before establishing the main coal fires.
2.	Env-A 1606.01(a) (formerly Env-A 402.04(a) and (b)) Coal Sulfur Limits	MK1 & MK2	For coal-burning devices placed in operation before April 15, 1970: A) The sulfur content of coal fired in MK1 and MK2 shall not exceed 2.0 lb/mmBtu averaged over any consecutive 3-month period; and B) The sulfur content of coal fired in MK1 and MK2 shall not exceed 2.8 lb/mmBtu.
3.	Env-A 1604.01(a) (formerly Env-A 402.02(a)) & 40 CFR 60 Subpart Dc §60.42c(d) Sulfur Content Limits for Liquid Fuels	MKEB & Facility Wide	The maximum sulfur content of No. 2 fuel oil and JP-4 aviation fuel shall not exceed 0.40% sulfur by weight.[10]
4.	Temporary Permit FP-T-0054 MK1-Maximum Fuel Consumption Rates	MK1	A) Coal: The maximum bituminous coal consumption rate for MK1 shall be limited to 48.5 tons per hour and shall not exceed 425,289 tons during any consecutive 12 month period.[11] B) No. 2 Fuel Oil: The maximum No. 2 fuel oil consumption rate to MK1 shall be limited to 1,656 gallons per hour and shall not to exceed 14.5 million gallons during any consecutive 12 month period.[12]

[10] DES has streamlined the sulfur content limits for liquid fuel. The MKEB is required by 40 CFR 60 Subpart Dc §60.42c(d) to use fuel oil with a sulfur content less than 0.5% sulfur by weight. This requirement to use fuel oil with a sulfur content of less than 0.40% by weight is a more stringent requirement.

[11] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption rates vary based on the actual heat content of the fuel burned.

[12] The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
5.	Temporary Permit TP-B-0462 MK2-Maximum Fuel Consumption Rates	MK2	A) Coal: The maximum bituminous coal consumption rate for MK2 shall be limited to 136.2 tons per hour and shall not exceed 1,193,078 tons during any consecutive 12 month period.[13] B) No. 2 Fuel Oil: The maximum No. 2 fuel oil consumption rate to MK2 shall be limited to 1,656 gallons per hour and shall not to exceed 14.5 million gallons during any consecutive 12 month period.[14]
6.	Temporary Permit FP-T-0054 MK1-ESP Operation	MK1	A) All available sections of each ESP on Unit #1 (MK1-PC1 and MK1-PC2) shall be in service at greater than 35 MW load. No more than a total of 7 sections in the two ESP units shall be out of service at greater than 35 MW load. If more than 7 sections are out of service at greater than 35 MW load, the owner or operator must notify (e.g., call or e-mail) DES within 24 hours of discovery unless the DES offices are closed then the next DES business day. At DES' request, PSNH shall be required to conduct particulate matter testing if more than 7 sections are out of service. During startup and when Unit #1 is below 35 MW of generation, 16 of 22 fields in MK1-PC1 must be in service and 4 of 10 fields in MK1-PC2 must be in service. B) PSNH –Merrimack Station shall continuously operate and maintain the ESP systems to minimize particulate matter emissions to meet permit conditions and to maintain compliance with Env-A 2000. The operation and maintenance shall include normal rounds by a qualified operator for checking and cleaning of the hoppers and transport lines. PSNH – Merrimack Station shall inspect and perform necessary maintenance on the ESP during each planned outage. All critical maintenance activities performed and corrective actions taken on the ESP systems shall be recorded and shall be made available for review at the request of DES.

[13] The heating value of bituminous coal is assumed to be 12,750 Btu/lb. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[14] The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
7.	Temporary Permit TP-B-0462 MK2-ESP Operation	MK2	A) All available sections of each ESP on Unit #2 (MK2-PC4 and MK2-PC5) shall be in service at greater than 120 MW of generation. If more than 8 sections are out of service at greater than 120 MW load, the owner or operator must notify (e.g., call or e-mail) DES within 24 hours of discovery unless the DES offices are closed then the next DES business day. At DES' request, PSNH shall be required to conduct particulate matter testing if more than 8 sections are out of service. During startup and when Unit #2 is below 120 MW of generation, 4 of 12 fields in MK2-PC4 must be in service and 12 of 24 fields in MK2-PC5 must be in service. B) PSNH –Merrimack Station shall continuously operate and maintain the ESP systems to minimize particulate matter emissions to meet permit conditions and to maintain compliance with Env-A 2000. The operation and maintenance shall include normal rounds by a qualified operator for checking and cleaning of the hoppers and transport lines. PSNH – Merrimack Station shall inspect and perform necessary maintenance on the ESP during each planned outage. All maintenance activities performed and corrective actions taken on the ESP systems shall be recorded and shall be made available for review at the request of DES.
8.	Temporary Permits FP-T-0054 & TP-B-0462 MK1 & MK2 Opacity Limits	MK1 & MK2	In accordance with Env-A 2002.01, during normal operation, the average opacity shall not exceed 40% for any continuous 6-minute period, except under the following conditions. In accordance with Env-A 2002.04(b), the average opacity may exceed 40% during periods of startup, shutdown, malfunction, soot blowing, grate cleaning, and cleaning of fires, for a non-overlapping set or sets of time up to 60 minutes in any 8-hour period. The hourly average opacity may not exceed 30% opacity except during the eight hours preceding the generator being phased on-line (boiler startup) or the eight hours after the generator being tripped off-line (boiler shutdown).

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
9.	Env-A 404.01 State Acid Rain Deposition Control Program & Temporary Permits FP-T-0054 and TB-B-0462	MK1 & MK2	The total sulfur dioxide emissions from PSNH - Merrimack Station (MK1 & MK2), Newington Station (Unit 1), and Schiller Station (Units 4, 5, & 6) shall not exceed 55,150 tons per calendar year.
10.	Env-A 2002.06 (formerly Env-A 1202.05(b)) and Temporary Permit FP-T-0054 MK1 TSP Emission Limit	MK1	A) The maximum allowable total suspended particulate matter (TSP) emission rate from MK1, including emissions rates experienced during periods of flyash re-injection, shall be limited to 0.27 lb/mmBtu. The maximum TSP emission rate is obtained from use of the equation below: $E = 0.880 * I^{-0.166}$ Where: E = maximum allowable particulate matter emission rate in lb/mmBtu; and I = maximum gross heat input rate in mmBtu/hr. B) Maximum TSP emissions from MK1 shall not exceed 1,463.1 tons during any consecutive 12 month period.[15]
11.	Env-A 2003.06 (formerly Env-A 1202.05(b)) and Temporary Permit TP-B-0462 MK2 TSP Emission Limit	MK2	A) The maximum allowable total suspended particulate matter (TSP) emission rate from MK2, including emissions rates experienced during periods of flyash re-injection, shall be limited to 0.227 lb/mmBtu. The maximum TSP emission rate is obtained from use of the equation below: $E = 0.880 * I^{-0.166}$ Where: E = maximum allowable particulate matter emission rate in lb/mmBtu; and I = maximum gross heat input rate in mmBtu/hr. B) Maximum TSP emissions from MK2 shall not exceed 3,458.6 tons during any consecutive 12 month period.[16]
12.	40 CFR §76.6(a)(2), Env-A 1211.03(d)(1), RACT Order ARD-97-001 Condition D.1.a.ii, and Env-A 1211.18	MK2	The maximum NOx emissions from MK2 shall not exceed the following: A) 0.86 lb NOx/mmBtu heat input on an annual average basis pursuant to 40 CFR 76.6(a)(2); B) 15.4 tons per 24-hour calendar day pursuant to 1211.03(d)(1); and C) 29.1 tons per calendar day pursuant to RACT Order ARD-97-001 Condition D.1.a.ii issued in accordance with Env-A 1211.18 when combined with MK1 (See Condition VIII, E.1.).
13.	RACT Order ARD-97-001 Condition D.1.c, Condition	MK1	The maximum NOx emissions from MK1 shall not exceed the following: A) 1.22 lb NOx/mmBtu heat input on a 7-calendar day average basis[17] pursuant to RACT Order ARD-97-001 Condition D.1.c issued in

[15] The maximum TSP emission limitation for MK1 of 1,463.1 tons during any consecutive 12-month period is calculated based on the lb/mmBtu limitation pursuant to Env-A 2002.06 (without rounding) multiplied by the maximum design capacity of 1238 mmBtu/hr multiplied by 8760 hours/yr and divided by 2000 lb/ton.

[16] The maximum TSP emission limitation for MK2 of 3458.6 tons during any consecutive 12-month period is calculated based on the lb/mmBtu limitation pursuant to Env-A 2002.06 (without rounding) multiplied by the maximum design capacity of 3473 mmBtu/hr multiplied by 8760 hours/yr and divided by 2000 lb/ton.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
	D.1.b, and Condition D.1.a.ii issued in accordance with Env-A 1211.18		accordance with Env-A 1211.18; B) 18.1 tons per 24-hour calendar day when MK2 is not in full operation[18] pursuant to RACT Order ARD-97-001 Condition D.1.b issued in accordance with Env-A 1211.18 (See Condition VIII, E.2.); and C) 29.1 tons per calendar day when combined with MK2 pursuant to RACT Order ARD-97-001 Condition D.1.a.ii issued in accordance with Env-A 1211.18 (See Condition VIII, E.1.1).
14.	State Permits to Operate PO-B-0034 & PO-B-0035	MKCT1 & MKCT2	Maximum fuel consumption rate of No.1 fuel oil or JP-4 shall not exceed 2,279 gal/hr and 19.96 million gallons during any consecutive 12-month period for each CT.[19]
15.	Env-A 2002.01 (formerly Env-A 1202.01)	MKCT1 & MKCT2	Average opacity from the CTs shall not be in excess of 40% for any continuous 6 minute period.
16.	State Permit to Operate PO-B-1788	MKEG	Maximum fuel consumption rate of No. 2 fuel oil shall not exceed 28.7 gal/hr and 14,350 gallons during any consecutive 12 month period.[20]
17.	Env-A 1211.02(j) (formerly Env-A 1211.01(j))	MKEG	Each emergency generator shall be limited to a maximum of 500 hours of operation during any consecutive 12-month period. The combined theoretical potential NOx emissions of all emergency generators at PSNH – Merrimack Station are limited to less than 25 tons for any consecutive 12-month period. If either of these conditions is exceeded, all such emergency generators become immediately subject to Env-A 1211.11.
18.	Env-A 2002.02	MKEG	Average opacity from the MKEG shall not be in excess of 20% for any continuous 6 minute period.

[17] This rolling 7-day average shall be calculated by adding up 7 consecutive 24-hour calendar day averages and dividing the sum by 7. Each 24-hour calendar day average shall be calculated using valid CEM data only. Hours when there are no fires in the boiler and the CEM is not activated shall not be included in the 24-hour calendar day average. The rolling 7-day average shall be calculated using days when there is valid CEM data only. Days when there are no fires in the boiler and the CEM is not activated shall not be included in the 7-day average.

[18] Full operation is defined as a unit operating with the CEM activated collecting valid data for all 24 hours in a calendar day. The CEM is activated and starts collecting valid data when fires are put in the boiler.

[19] The heating value of the fuel is assumed to be 140,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[20] The heating value of the fuel is assumed to be 137,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
19.	Env-A 2002.02, Env-A 2002.04, & 40 CFR 60 Subpart Dc Section 60.43c(c) and (d)	MKEB	A) Pursuant to Env-A 2002.02, the owner or operator shall not cause or allow average opacity in excess of 20% for any continuous 6-minute period except as specified in Condition C) below. B) Pursuant to 40 CFR 60.43c (c) and (d), no owner or operator shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. This opacity standard applies at all times, except during periods of startup, shutdown or malfunction. C) Pursuant to Env-A 2002.04 (a), for steam generating units subject to 40 CFR 60, no more than one of the following two exemptions shall be taken: 1. During periods of startup, shutdown and malfunction, average opacity shall be allowed to be in excess of 20% for one period of 6 continuous minutes in any 60-minute period; or 2. During periods of normal operation, soot blowing, grate cleaning, and cleaning of fires, average opacity shall be allowed to be in excess of 20% but not more than 27% for one period of 6 continuous minutes in any 60-minute period. D) Pursuant to Env-A 2002.04 (d), (e), and (f), exceedances of the opacity standard in Env-A 2002 shall not be considered violations if the Owner or Operator demonstrates to DES that such exceedances: 1. Were the result of the adherence to good boiler operating practices which, in the long term, result in the most efficient or safe operation of the boiler; 2. Occurred during periods of cold startup of a boiler over a continuous period of time resulting in efficient heat-up and stabilization of its operation and the expeditious achievement of normal operation of the unit; 3.Occurred during periods of continuous soot blowing of the entire boiler tube section over regular time intervals as determined by the operator and in conformance with good boiler operating practice; or 4. Were the result of the occurrence of an unplanned incident in which the opacity exceedance was beyond the control of the operator and in response to such incident, the operator took appropriate steps in conformance with good boiler operating practice to eliminate the excess opacity as quickly as possible.
20.	Env-A 2002.08 (formerly Env-A 1202.07)	MKEG	The TSP emission rate shall not exceed 0.30 lb/mmBtu based on a 24-hour calendar day.[21]

[21] The Owner or Operator shall demonstrate compliance with this requirement by using an approved EPA AP-42 emission factor and EPA/DES approved heat input content (Btu/gal). This calculation shall be maintained on file at the facility.

Table 5 - Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
21.	State Permits to Operate PO-BP-2416 & PO-BP-2417	MKPCC & MKSCC	Based on the maximum coal usage allowed in MK1 and MK2, the maximum annual coal throughput shall be limited to 1,618,367 tons during any consecutive 12-month period.
22.	State Permits to Operate PO-BP-2416 & PO-BP-2417	MKPCC & MKSCC	The primary crusher is located underground beneath the rail car track hopper and is fully enclosed to reduce fugitive emissions. The secondary coal crushers are fully enclosed in an aboveground building to reduce fugitive emissions. The coal crusher systems shall be inspected and maintained regularly. Any failures of these enclosures to prevent fugitive emissions shall be repaired, as necessary.
23.	Env-A 2103.02 (formerly Env-A 1203.05)	MKPCC & MKSCC	Visible fugitive emissions or visible stack emissions shall not exceed an average of 20% opacity for any continuous 6 minute period, except one period of 6 continuous minutes in any 60-minute period during startup, shutdown, or malfunction.
24.	40 CFR 72, 73, 75, 76, and 77.	MK1 & MK2	PSNH – Merrimack Station shall comply with the applicable Federal Acid Rain Program provisions.
25.	40 CFR 68 and 1990 CAA Section 112(r)(1) Accidental Release Program Requirements	Facility wide	The facility is subject to the Purpose and General Duty clause of the 1990 Clean Air Act, Section 112(r)(1). General Duty includes the following responsibilities: (A) Identify potential hazards that may result from such releases using appropriate hazard assessment techniques; (B) Design and maintain a safe facility; (C) Take steps necessary to prevent releases; and (D) Minimize the consequences of accidental releases that do occur. The facility stores quantities of ammonia above the threshold level and has submitted a risk management plan to the Part 68 implementing agency as required by the 1990 Clean Air Act, Section 112(r)(7)(ii). Administrative controls will be established by PSNH – Merrimack Station in order to monitor that inventories of regulated substances (except for ammonia) are maintained below the specified threshold quantities. If, in the future, PSNH – Merrimack Station wishes to store quantities of other regulated substances above the threshold levels, a risk management plan shall be submitted to the Part 68 implementing agency in a timely manner, prior to exceeding threshold quantity levels.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	**Regulatory Cite**	**Applicable Emission Unit**	**Applicable Requirement**
26.	Temporary Permit TP-B-0490	MKEB	The maximum gross heat input rate of the Emergency Boiler is limited to less than or equal to 96.0 mmBtu/hr.
27.	RSA 125-C:6, RSA 125-C:11, Env-A 606.04, & Temporary Permit TP-B-0490	MKEB	A) Pursuant to Env-A 606.04, the owner or operator shall limit the maximum fuel consumption rate of MKEB to the following: 1) For No. 2 fuel oil, 520 gal/hr and 11,760 gal/day[22]; or 2) For on-road low sulfur diesel oil, 701 gal/hr. B) To avoid NSR/PSD, the owner or operator shall limit the maximum fuel consumption rate of MKEB to the following: 1) For No. 2 fuel oil, 1,405,000 gallons per consecutive 12-month period; or 2) For on-road low sulfur diesel oil, 2,490,000 gallons per consecutive 12-month period; or 3) For any combination of the above fuels, fuel consumption rates such that the emissions do not exceed the significance levels contained in Table 5, Item 33.
28.	RSA 125-C:6, RSA 125-C:11, Env-A 606.04, & Temporary Permit TP-B-0490	MKEB	A) The Emergency Boiler is allowed to operate for training purposes or performance testing with MK1 or MK2 in operation. B) The Emergency Boiler is allowed to operate with either or both Combustion Turbines #1 & #2 in operation and the Emergency Generator in operation.
29.	Temporary Permit TP-B-0490	MKEB	The Emergency Boiler can be replaced each year with a similar unit at or below the fuel consumption limits in Table 1 and which satisfies the stack height requirements in Table 2.
30.	40 CFR 60 Subpart Dc § 60.42c(i)	MKEB	The fuel oil sulfur limits apply at all times, including periods of startup, shutdown, and malfunction.
31.	Env-A 606.04 & 40 CFR 60 Subpart Dc § 60.42c(d)	MKEB	The sulfur content of on-road low sulfur diesel oil shall not exceed 0.05 percent sulfur by weight.[23]

[22] The heating value of No. 2 fuel oil is assumed to be 140,000 Btu/gal. The heating value of on-road low sulfur diesel fuel is assumed to be 137,000 Btu/gal. The fuel consumption rates may vary based on the actual heat content of the fuel burned.

[23] DES has streamlined the sulfur content requirements for on-road low sulfur diesel oil. MKEB is required by 40 CFR 60.42c(d) to use fuel oil with a sulfur content less than 0.5% sulfur by weight. To comply with the SO_2 NAAQS as demonstrated through air dispersion modeling conducted pursuant to Env-A 606.04, the on-road low sulfur diesel oil must have a sulfur content that does not exceed 0.05% sulfur by weight. The 0.05% sulfur by weight limit required by Env-A 606.04 (modeling for SO2 NAAQS) is more stringent than the 0.5% sulfur by weight limit specified in 40 CFR 60.42c(d). Note that no additional limit on sulfur content beyond that required by Env-A 1604.01(a) (0.4% sulfur by weight) is necessary for compliance with the SO_2 NAAQS for No. 2 fuel oil.

<table>
<tr><th colspan="4">Table 5 – Federally Enforceable Operational and Emission Limitations</th></tr>
<tr><th>Item No.</th><th>Regulatory Cite</th><th>Applicable Emission Unit</th><th>Applicable Requirement</th></tr>
<tr><td>32.</td><td>Env-A 606.04 and Temporary Permit TP-B-0490</td><td>MKEB</td><td>Pursuant to Env-A 606.04, the owner or operator shall limit the hourly[24] emissions from MKEB as provided in the Table below:
<table>
<tr><th>Pollutant</th><th>Short-term limit (lb/hr)[25]</th></tr>
<tr><td>NOx</td><td>13.72</td></tr>
<tr><td>SO2</td><td>38.96</td></tr>
<tr><td>CO</td><td>3.43</td></tr>
<tr><td>PM10</td><td>2.26</td></tr>
<tr><td>VOC</td><td>0.14</td></tr>
</table></td></tr>
<tr><td>33.</td><td>Temporary Permit TP-B-0490 (PSD/NSR Avoidance)</td><td>MKEB</td><td>To avoid NSR/PSD, the owner or operator shall limit the consecutive 12-month emissions from MKEB as provided in the Table below:
<table>
<tr><th>Pollutant</th><th>Tons per consecutive 12-month period[26]</th></tr>
<tr><td>NOx</td><td>25.0</td></tr>
<tr><td>SO2</td><td>40.0</td></tr>
<tr><td>CO</td><td>100.0</td></tr>
<tr><td>PM10</td><td>15.0</td></tr>
<tr><td>VOC</td><td>25.0</td></tr>
</table></td></tr>
<tr><td>34.</td><td>40 CFR 61 Subpart M, Env-A 504.01(e) and Env-A 1800 Asbestos Management and Control</td><td>Facility wide</td><td>PSNH – Merrimack Station shall comply with the asbestos requirements of Env-A 1800 and 40 CFR 61.145 during demolition and/or renovation.</td></tr>
<tr><td>35.</td><td>40 CFR 63 Subpart YYYY MACT for Stationary Combustion Turbines</td><td>MKCT1 & MKCT2</td><td>The MACT is applicable to the combustion turbines, but no emission limitations, operating requirements or monitoring, recordkeeping, or reporting requirements are specified for existing units.</td></tr>
</table>

[24] The TSP and PM10 emission limits have been streamlined. Env-A 2002.08 limits TSP emissions to 0.30 lb/mmBtu. The PM10 hourly and annual emission limits of 2.26 lb/hr and 15 tpy are more stringent.

[25] Short term emissions limits of criteria pollutants in pounds per hour (lb/hr) are based on United States Environmental Protection Agency (EPA) AP-42 5th Edition January 1995, Section 1.3 Fuel Combustion (Updated 9/98) Tables 1.3-1, 1.3-2, and 1.3-3.

[26] Consecutive 12-month period emissions limits are the significance levels to keep the PSNH - Merrimack Station below major modification levels requiring Non-Attainment Review or Prevention of Significant Deterioration Review.

Table 5 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
36.	Env-A 2002.08 (formerly Env-A 1202.07)	MKCT1 & MKCT2	The maximum allowable total suspended particulate matter (TSP) emission rate from each device shall be limited to 0.34 lb/mmBtu. The maximum TSP emission rate is obtained from use of the equation below: $E = 0.880 * I^{-0.166}$ Where: E = maximum allowable particulate matter emission rate in lb/mmBtu; and I = maximum gross heat input rate in mmBtu/hr.
37.	Env-A 2002.08 (formerly Env-A 1202.07)	MKEB	The TSP emission rate from MKEB shall not exceed 0.30 lb/mmBtu.
38.	Env-A 1211.12 NOx RACT	MKEB	The maximum NOx emission rate from MKEB shall not exceed 0.20 lb/mmBtu based on a 24-hour calendar day average.

C. Annual SO_2 Allowance Programs (40 CFR 72, 40 CFR 73, Env-A 611.07, and Env-A 2900)

1. SO_2 Allowance Allocation

a) In accordance with 40 CFR Part 73, SO_2 allowances pursuant to the Federal Acid Rain Program for this facility are allocated as indicated in the following table:

Table 6 – Federal Annual SO_2 Allowance Allocations (tons) (40 CFR 73.10 Table 2)		
	2000 - 2009	2010 and Beyond
MK1	4288	4296
MK2	9242	9257

b) Pursuant to Env-A 2906.02 [State-only enforceable], *Allocation of SO2 Allowances*, for 2007 and subsequent years, PSNH's Schiller, Merrimack and Newington stations shall transfer the SO_2 Allowances allocated pursuant to the Federal Acid Rain Program to DES, and DES shall transfer SO_2 allowances (7,289 tons) calculated pursuant to Env-A 2900 plus any potential bonus allowances calculated pursuant to Env-A 2906.07, *Bonus Allocation of SO2 Allowances*, back to PSNH's Schiller, Merrimack, and Newington stations. The amount of SO_2 Allowances allocated to PSNH Merrimack shall be determined according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology*.

2. Compliance

   a) Pursuant to 40 CFR 73.35, the Permittee shall comply with the SO_2 emission limitation requirements.

   b) At the end of each calendar year, the Permittee shall hold sufficient SO_2 allowances equivalent to the SO_2 emissions during that calendar year.

3. General Provisions

   Pursuant to Env-A 611.07, SO_2 allowances lawfully held or acquired by the Permittee shall be governed by the following:

   a) Emissions from the affected units shall not exceed any SO_2 allowances held by the affected unit;

   b) The number of SO_2 allowances held by the Permittee shall not be limited;

   c) The Permittee shall not use SO_2 allowances to avoid compliance with any other applicable requirement of either state or federal rules or of the provisions of the Clean Air Act; and

   d) Any SO_2 allowances held by the Permittee shall be accounted for according to the procedures established in the applicable provisions of 40 CFR 72, 40 CFR 73, and 40 CFR 76.

4. Excess Emissions

   Pursuant to 40 CFR 72.9(e), if the Permittee has excess emissions, the Permittee shall submit a proposed offset plan as required under 40 CFR 77 and pay the penalty and any interest without demand pursuant to 40 CFR 77.

5. Allowance Transfer

   The Permittee shall transfer allowances according to the procedures in 40 CFR 73.50.

D. Ozone Season NOx Budget Trading Program (Env-A 3200)

1. The NOx allowances shall be allocated to PSNH - Merrimack Station for each subsequent control periods according to the methodology in Env-A 3207.04, *Allowance Allocation Methodology*.

2. Ozone Season NOx Emissions Cap

   a) Pursuant to Env-A 3200, PSNH - Merrimack Station shall not emit NOx emissions during any control period in excess of the amount of NOx allowances held in Merrimack Station's NATS compliance account for that control period as of the allowance transfer deadline of November 30.

b) Pursuant to Env-A 3200, PSNH - Merrimack Station may obtain additional NOx allowances to comply with the NOx Budget Program.

3. Allowance Transfer and Use

   a) Pursuant to Env-A 3209.01, *Marketable Emissions Authorization*, an allowance shall be a marketable emissions authorization that may be bought, sold, or traded at any time during any year, not just the current year.

   b) Pursuant to Env-A 3209.02, *Limited Authorization,* an allowance shall only be used for compliance with the NOx Budget Program in a designated compliance year by being in a compliance account as of the allowance transfer deadline of November 30, or by being transferred into the compliance account by an allowance transfer submitted by the allowance transfer deadline.

   c) PSNH - Merrimack Station shall comply with the NOx allowance transfer and use provisions pursuant to Env-A 3209, *Allowance Transfer and Use.*

   d) Pursuant to Env-A 3209.09, *Price Disclosure,* subject to a claim of confidentiality in accordance with Env-A 103, PSNH - Merrimack Station shall make available to any person, all information regarding transaction cost and allowance price.

4. Allowance Banking

   a) Pursuant to Env-A 3210.01, *Retention of Unused Allowances,* the banking of allowances shall be permitted to allow the retention of unused allowances from one year to a future year in either a compliance account, an overdraft account, or a general account.

   b) Pursuant to Env-A 3210.02, *Account Designation,* unused allowances as of the end of the allowance transfer deadline shall be retained in the compliance, overdraft, or general account and designated as banked allowances after the NATS administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to Env-A 3215, *End-of-Season Reconciliation.*

   c) Pursuant to Env-A 3210.03, *Requirements for Use*, banked allowances may be used in the current year on a 1-for-1 basis.

5. End-of-Season Reconciliation

   a) Pursuant to Env-A 3206.01, *Limited Authorization*, PSNH - Merrimack Station shall, no later than November 30th of each calendar year, hold a quantity of NOx allowances in PSNH - Merrimack Station's current year NATS account that is equal to or greater than the total NOx emitted from PSNH - Merrimack Station during the period May 1st through September 30th of the subject year.

   b) PSNH - Merrimack Station shall determine compliance and reconcile allowances by November 30th of each year for the control period of that year pursuant to Env-A 3215.

6. Authorized Account Representative (Env-A 3211.04)

   a) Only the AAR or alternate AAR shall request transfers of allowances in a NATS account.

   b) The AAR or alternate AAR shall be responsible for all transactions and reports submitted to the NATS.

   c) The alternative AAR shall have the same authority as the primary representative, however, all correspondence from the NATS administrator shall be directed to the primary AAR.

   d) Pursuant to Env-A 3211.05 (f), PSNH - Merrimack Station shall replace an AAR by submitting a revised Account Certificate of Representation to the NATS administrator along with the information contained in Env-A 3211.05(b) and (c) and the name of the AAR who is being replaced.

7. Conversion of Allowances to DERs

   Pursuant to Env-A 3207.05, PSNH - Merrimack Station may convert unused allowances to DERs in accordance with Env-A 3206.02(e) for use as NSR offsets during the ozone season and the procedures for DER generation pursuant to Env-A 3103. Upon conversion, PSNH - Merrimack Station shall surrender those converted allowances as if they had been used for actual emissions. Under no circumstances, except as noted above, shall unused allowances be converted to, or used as, DERs or ERCs.

8. Prohibition on Property Rights (Env-A 3207.07)

   a) Neither an allowance nor any future allocations, which are subject to modification by DES, shall constitute a security or other form of property.

   b) An allowance shall not be used prior to the control period for which the allowance is allocated.

9. Excess Emissions and Enforcement Provisions (Env-A 3217)

   a) If emissions exceed the allowances held by PSNH - Merrimack Station by the allowance transfer deadline (November 30th), the NATS administrator shall automatically deduct three tons of allowances from the next control period for every ton of excess emissions from PSNH - Merrimack Station's compliance account or overdraft account.

   b) In accordance with RSA 125-J:4-a., for purposes of enforcement of the NOx Budget Program, in determining the number of days of violation, any excess emissions for the control period shall presume that each day in the control period of 153 days, constitutes a day in violation unless PSNH - Merrimack Station can demonstrate, through use of verifiable emissions data that a lesser number of days should be considered. In addition, each ton of excess emissions shall constitute a separate violation.

E. Non-Ozone Season NOx Allowances and NOx RACT Orders (NOx RACT Orders ARD-97-001 and ARD-98-001)

1. Pursuant to NOx RACT Order No. ARD-97-001, Condition D.1.a.ii., no later than May 31, 1999, PSNH - Merrimack Station shall comply with a NOx emissions cap no greater than 29.1 tons per calendar day for the combined NOx emissions from MK1 and MK2. This requirement shall not supersede future requirements for MK2 as listed in Env-A 1211.03(f) (formerly) (now it is Env-A 1211.03(d)) and any amendments, thereto.

2. Pursuant to NOx RACT Order No. ARD-97-001, Condition D.1.b., when MK2 is not in full operation, PSNH - Merrimack Station shall comply with a NOx emissions cap of 18.1 tons per calendar day for the NOx emissions from MK1 by May 31, 1995. This cap applies indefinitely into the future, until such time that it is modified or rescinded by DES and approved by EPA as a State Implementation Plan revision. This requirement shall not supersede future requirements for MK1. "Full operation" shall be defined as a unit operating with the CEM activated collecting valid data for all 24 hours on a calendar day. The CEM is activated and starts collecting valid data when fires are put in the boiler.

3. Pursuant to NOx RACT Order No. ARD-97-001, Condition D.1.c., PSNH - Merrimack Station shall comply with a NOx emission rate limit of 1.22 lb/mmBtu based on a rolling 7-day average for MK1 by May 31, 1995. This emission rate limit applies indefinitely into the future, until such time that it is modified or rescinded by DES and approved by EPA as a State Implementation Plan revision. This requirement shall not supersede future requirements for MK1. This rolling 7-day average shall be calculated by adding up 7 consecutive 24-hour calendar day averages and dividing the sum by 7. Each 24-hour calendar day average shall be calculated using valid CEM data only. Hours when there are no fires in the boiler and the CEM is not activated shall not be included in the 24-hour calendar day average. The rolling 7-day average shall be calculated using days when there is valid CEM data only. Days when there are no fires in the boiler and the CEM is not activated shall not be included in the 7-day average.

4. Pursuant to NOx RACT Order No. ARD-97-001, Condition D.1.d., PSNH – Merrimack Station shall demonstrate compliance with all of the above alternative emission limits (AEL) by monitoring the hourly emissions from MK1 and MK2 in accordance with Env-A 1211.22 (formerly Env-A 1211.21). "Alternative emission limits" or AEL shall be defined as limits other than those listed in Env-A 1211, and the above limits in Items 1., 2., and 3. are not alternatives to each other.

5. Pursuant to NOx RACT Order ARD-97-001, Condition D.1.e., within 30 days following the end of each calendar quarter, PSNH – Merrimack Station shall report any excess emissions (emissions greater than the above AEL) which occurred.

6. Pursuant to NOx RACT Order ARD-97-001, Condition D.1.f., PSNH – Merrimack Station shall comply with the remainder of the original compliance plan as listed in C.5.b. – C.5.e. of the NOx RACT Order No. ARD-97-001 (Items 7 through 10 below).

7. Pursuant to NOx RACT Order ARD-97-001, Condition C.5.b., PSNH – Merrimack Station shall comply with the requirement in Env-A 1211.03(c)(1)b.2. of maintaining an emission rate from MK2 at or below 1.40 lb/MMBtu based on a 24-hour calendar day average and with the requirements in Env-A 1211.03(d) of maintaining emissions from MK2 at or below 35.4 tons/day and 12,921 tons/year during the period May 31, 1995 through May 31, 1999 by the installation of Selective Catalytic Reduction (SCR).

8. Pursuant to NOx RACT Order ARD-97-001, Condition C.5.c.i., PSNH – Merrimack Station shall initially comply with the requirement in Env-A 1211.13(b) of maintaining emission rates from MKCT1 and MKCT2 at or below 0.90 lb/MMBtu based on an hourly average; and Condition C.5.c.ii., based on the results of future periodic testing, PSNH – Merrimack Station shall maintain future compliance by emissions averaging (if necessary) between MK1, MK2, MKCT1, and MKCT2.

9. Pursuant to NOx RACT Order ARD-97-001, Condition C.5.d., PSNH – Merrimack Station shall comply with Env-A 1211.11 for the MKEG (emergency generator).

10. Pursuant to NOx RACT Order ARD-97-001, Condition C.5.e., PSNH – Merrimack Station shall comply with the testing requirements in Env-A 1211.20 (formerly Env-A 1211.21), the monitoring requirements in Env-A 1211.21 (formerly Env-A 1211.22), and the recordkeeping and reporting requirements in Env-A 905 and Env-A 909, respectively (formerly Env-A 901.06 and Env-A 901.07, respectively).

11. Pursuant to NOx RACT Order ARD-97-001, Condition E., the preamble to the USEPA's proposed Model Open Market Trading Rule or OMTR (60 Federal Register 39668, August 3, 1995) states: "b. Overcompliance With An Alternative Emission Limit - In many states, sources are given flexibility from RACT requirements when the State grants them an alternative emission limit (AEL) that is less stringent than the RACT standard. The OMTR would not allow sources to generate DER's by reducing emissions below levels required by an AEL but still above levels required by the otherwise applicable RACT standard. Sources subject to AEL's could, however, generate DER's by reducing emissions below the levels associated with the otherwise applicable RACT standard."

    a) PSNH - Merrimack Station shall not be allowed to generate DERs by reducing emissions below levels required by the above AEL, but PSNH - Merrimack Station shall be allowed to generate DERs by reducing emissions below the emissions limitations and emission rate limitations as listed in Env-A 1211. In the event that PSNH - Merrimack Station cannot meet the above AEL for some unforeseen reason (e.g., control equipment malfunction), PSNH - Merrimack Station may use DERs for compliance purposes.

    b) This Order grants approval to PSNH - Merrimack Station to quantify DERs in accordance with the protocols submitted by PSNH - Merrimack Station to comply with these AEL. Upon submittal by PSNH - Merrimack Station of a "Notice of Generation" and accompanying documentation, as described in Env-A 3100 which was proposed for adoption on October 10, 1996, PSNH - Merrimack Station shall be allowed to trade 142 tons of NOx DERs created during the period June 22, 1995 through September 30, 1995 to other sources in New Hampshire in accordance with Env-A 3100. PSNH - Merrimack

Station may be allowed to trade additional tons of NOx DERs created during subsequent periods, upon submittal of additional "Notices of Generation" and accompanying documentation.

12. Pursuant to NOx RACT Order No. ARD-98-001, Condition D.1.a., PSNH - Merrimack Station shall comply at all times with a maximum emission limit for MK2 of 15.4 tons of NOx per 24-hour calendar day by May 31, 1999. Ozone season Discrete Emissions Reductions (DERs) may be used to comply with this limit during the ozone season and non-ozone season DERs may be used during the non-ozone season.

13. Pursuant to NOx RACT Order No. ARD-98-001, Condition D.1.c., PSNH's Schiller, Merrimack, and Newington Stations (MK1, MK2, NT1, SR4, SR5, and SR6) shall comply with a combined NOx emissions cap of 8208 tons for the non-ozone season beginning on October 1st and ending on April 30th. Ozone season DERs and non-ozone season DERS may be used to comply with this non-ozone season limit. Previously generated (1995 through 1998) DERs may be used to comply with this emissions cap. For the purpose of compliance with this RACT Order, DERs may be generated from PSNH's Newington and Schiller Stations, in accordance with the PSNH Discrete Emissions Reductions Protocol dated April 10, 1998, submitted by PSNH and listed in Items 17 and 18 below to comply with this emissions cap.[27]

14. Pursuant to NOx RACT Order No. ARD-98-001, Condition D.1.d., beginning in 2003, PSNH Merrimack Station shall comply during the 153-day ozone season with an emission limit in terms of a seasonal NOx emissions cap of 3,727 tons minus any tons allocated to new sources and minus 100 tons allocated to a set-aside account dedicated to fulfilling alternative I/M requirements (while such requirements are in effect in New Hampshire) per calendar season for the combined NOx emissions from MK1, MK2, NT1, SR4, SR5, and SR6 during the 2003 and post-2003 ozone seasons in accordance with Env-A 3200 upon adoption. Consistent with the OTC Model NOx Budget Trading Program, compliance may be achieved by allowance trading within the Ozone Transport Region (OTR). The specific methodology for allocating allowances among applicable budget sources for 2003 and beyond shall be determined by NHDES – Air Resources Division and implemented as an amendment to Env-A 3200 prior to 2003.[28]

15. Pursuant to NOx RACT Order No. ARD-98-001, Condition D.1.f., PSNH Merrimack Station shall demonstrate compliance with the alternative emission limits in this RACT Order by monitoring the hourly emissions from MK1, MK2, NT1, SR4, SR5, and SR6 in accordance with Env-A 1211.21 (formerly Env-A 1211.22) and Env-A 3200. Alternative emission limits shall be defined as limits other than those listed in Env-A 1211 and RACT Order No. ARD-97-001, and the above limits are not alternatives to each other.

16. Pursuant to NOx RACT Order No. ARD-98-001, Condition D.1.g., within 30 days following the end of each calendar quarter, PSNH Merrimack Station shall report any excess emissions (emissions greater than the above alternative emission limits) which occurred.

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[27] Note that the provisions of Env-A 2900 contain more stringent provisions.

[28] This provision has been superceded by Env-A 3200.

F. Multiple Pollutant Annual Budget Trading and Banking Program (Env-A 2900) [State-only enforceable]

1. SO_2 Allowance Allocation

   Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, DES shall allocate SO_2 Allowances to PSNH - Merrimack Station according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology* for 2007 and subsequent years.

2. NOx Allowance Allocation

   a) Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, DES shall allocate NOx Allowances to PSNH - Merrimack Station according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology* for 2007 and subsequent years.

   b) Pursuant to Env-A 2900 [State enforceable only], *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, for 2007 and subsequent years, DES shall calculate the difference between the annual NOx budget (no more than 3,644 tons) and the ozone season NOx allowances allocated pursuant to Env-A 3200.

   c) Pursuant to Env-A 2900 [State enforceable only], *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, for 2007 and subsequent years, DES shall allocate annual NOx allowances equivalent to the difference between the annual NOx budget and the ozone season NOx allowances to PSNH's Schiller, Merrimack, and Newington stations.

3. Allowance Transfer and Use

   a) Pursuant to Env-A 2907.01, *Marketable Emissions Authorization*, an allowance shall be a marketable emissions authorization that may be bought, sold, or traded at any time during any year, not just the current year.

   b) Pursuant to Env-A 2907.02, *Limited Authorization,* an allowance shall only be used for compliance with the Multiple Pollutant Annual Budget Trading and Banking Program in a designated compliance year by being in a compliance or overdraft account as of the allowance transfer deadline, or by being transferred into the compliance account by an allowance transfer submitted by the allowance transfer deadline.

   c) PSNH - Merrimack Station shall comply with the allowance transfer and use provisions pursuant to Env-A 2907, *Allowance Transfer and Use,* and Env-A 2909, *Allowance Tracking System.*

   d) Pursuant to Env-A 2907.08, *Price Disclosure,* subject to a claim of confidentiality in accordance with Env-A 103, PSNH - Merrimack Station shall make available to any person, all information regarding transaction cost and allowance price.

e) Pursuant to Env-A 2907.09, *Use of Allowances by Utilities* and RSA 125-J:5, X, the use of allowances by a utility as defined in RSA 362:2, shall be subject to such additional conditions as ordered pursuant to applicable law by the PUC.

4. Allowance Banking

a) Pursuant to Env-A 2908.01, *Retention of Unused Allowances,* the banking of allowances shall be permitted to allow the retention of unused allowances from one year to a future year in either a compliance account, an overdraft account, or a general account.

b) Pursuant to Env-A 2908.02, *Account Designation,* unless otherwise permitted pursuant to Env-A 2909.03, *General Accounts,* unused allowances as of the end of the allowance transfer deadline shall be retained in the compliance, overdraft, or general account and designated as banked allowances after the ATS administrator has made all deductions for a given year from the compliance account or overdraft account pursuant to Env-A 2913, *Compliance Certification.*

5. Authorized Account Representative (Env-A 2909.04)

a) Only the AAR or alternate AAR shall request transfers of allowances in an ATS account.

b) The AAR or alternate AAR shall be responsible for all transactions and reports submitted to the ATS.

c) The alternative AAR shall have the same authority as the primary representative, however, all correspondence from the ATS administrator shall be directed to the primary AAR.

d) Pursuant to Env-A 2909.05 (f), PSNH - Merrimack Station shall replace an AAR by submitting a revised Account Certificate of Representation to the ATS administrator along with the information contained in Env-A 2909.05(b) and (c) and the name of the AAR who is being replaced.

6. End-of-Year Reconciliation

a) Pursuant to Env-A 2904.01, *Limited Authorization*, PSNH - Merrimack Station shall, no later than January 30th of each calendar year, hold respective quantities of SO_2, NOx, and CO_2 allowances in the PSNH - Merrimack Station's respective ATS accounts equal to or greater than the respective total SO_2, NOx, and CO_2 emitted from PSNH - Merrimack Station during the previous year.

b) Pursuant to Env-A 2912.01, *Determination of Compliance*, monitored emissions data as reported by PSNH - Merrimack Station to the ETS administrator, and as adjusted by the administrator to be in accordance with Env-A 2910, *Emissions Monitoring*, combined with allowance allocations and transfers recorded in the ATS, shall provide the basis for a determination of compliance.

c) PSNH - Merrimack Station shall determine compliance and reconcile allowances by January 30th of each year beginning in 2008 pursuant to Env-A 2913.

d) Pursuant to Env-A 2912.02, *Request for Deduction of Allowances*, each year prior to January 30th, the AAR shall request the ATS administrator to deduct previous year allowances from the compliance account or overdraft account equivalent to the number of available allowances to cover the emissions during the previous year. The AAR shall identify the compliance account or overdraft account from which the deductions shall be made and shall identify the serial number of the allowances to be deducted. If the AAR does not specify a serial number, allowances useable for that compliance year shall be deducted in the order of their arrival into PSNH - Merrimack Station's account, with allocated allowances being deducted first, followed by the deduction of transferred allowances.

e) Pursuant to Env-A 2912.04, *Procurement of Additional Allowances,* if the emissions of PSNH - Merrimack Station in the previous year exceed the allowances in PSNH - Merrimack Station's compliance account and overdraft account, PSNH - Merrimack Station shall obtain additional allowances by January 30th so that the total number of allowances in PSNH - Merrimack Station's compliance account and overdraft account, including allowance transfers properly submitted to the ATS administrator by January 30th, equals or exceeds the previous year annual emissions rounded to the nearest whole ton.

7. Excess Emissions and Enforcement Provisions (Env-A 2914)

   a) If emissions from PSNH – Merrimack Station exceed allowances held in PSNH - Merrimack Station's compliance account or overdraft account for the year as of the allowance transfer deadline (January 30th), the Allowance Tracking System administrator shall automatically deduct allowances from PSNH – Merrimack Station's compliance account or overdraft account for the next year at a rate of three allowances for every one ton of excess emissions.

   b) In accordance with RSA 125-O:7, for purposes of enforcement of the Multiple Pollutant Annual Budget Trading and Banking Program, in determining the number of days of violation, any excess emissions for the year shall create a presumption that each day in the year of 365 days, constitutes a day in violation unless PSNH - Merrimack Station can demonstrate, through use of verifiable emissions data that a lesser number of days should be considered. In addition, each ton of excess emissions shall constitute a separate violation.

8. Conversion of Allowances to DERs

   a) Pursuant to Env-A 2904.01 (d), allowances shall not be considered offsets, although NOx allowances which are not used to satisfy the requirements of Env-A 2900, and which are not banked, may be converted to non-ozone season NOx DERs in accordance with Env-A 3100.

b) Pursuant to Env-A 2904.02, *Conversion of Allowances to DERs or VERs* if PSNH - Merrimack Station converts unused NOx allowances to NOx DERs in accordance with Env-A 2904.01(d) and the procedures for DER generation pursuant to Env-A 3103, or converts unused CO2 allowances to VERs in accordance with Env-A 3800, PSNH - Merrimack Station shall surrender those converted allowances as if they had been used for actual emissions.

9. Prohibition on Property Rights (Env-A 2904.04)

a) Neither an allowance nor any future allocations, which are subject to modification by DES, shall constitute a security or other form of property.

b) An allowance shall not be used prior to the year for which the allowance is allocated.

G. Discrete Emission Reduction Trading Program (Env-A 3100)

PSNH - Merrimack Station shall be allowed to bank DERs for PSNH - Merrimack Station's own future use or trade with others in accordance with Env-A 3100.

H. Carbon Dioxide (CO_2) Budget Trading Program (Env-A 4600) (State-only Enforceable)

1. CO_2 Allowance Requirements (Env-A 4605.01)

a. The Owner or Operator of each CO_2 budget source and each CO_2 budget unit at the source shall hold CO_2 allowances available for compliance deductions under Env-A 4605.04, as of the CO_2 allowance transfer deadline, in the source's compliance account, in an amount not less than the total CO_2 emissions from fossil fuel-fired generation for the control period from all CO_2 budget units at the source, as determined in accordance with Env-A 4605, Env-A 4607, Env-A 4609.18, and Condition VIII.H.1.c, below.

b. CO_2 allowances shall be held in, deducted from, or transferred among CO_2 allowance tracking system accounts in accordance with Env-A 4606, Env-A 4607, Env-A 4608, and Env-A 4700.

c. For the purpose of determining compliance with Env-A 4600, total tons of CO_2 emissions for a control period[29] shall be calculated as the sum of all recorded hourly emissions, or the tonnage equivalent of the recorded hourly emissions rates, in accordance with Env-A 4609, with any remaining fraction of a ton equal to or greater than 0.50 ton rounded up to equal one ton and any fraction of a ton less than 0.50 ton rounded down to equal zero tons.

2. CO_2 Allowance Limitations (Env-A 4605.02)

a. A CO_2 allowance shall be a limited authorization to emit one ton of CO_2 in accordance with the CO_2 budget trading program.

[29] Control period means compliance period as defined in New Hampshire RSA 125-O:20, IV.

b. A CO_2 allowance shall not be deducted, in order to comply with the requirements of Env-A 4605.01(a), for a control period that ends prior to the year for which the CO_2 allowance was allocated.

c. A CO_2 offset allowance shall not be deducted, in order to comply with the requirements of Env-A 4605.01(a), beyond the applicable percent limitations set out in Env-A 4605.04(b).

d. Subject to Env-A 4605.02(e) and (f), no provision of the CO_2 budget trading program, the CO_2 budget permit application, or the CO_2 budget permit shall be construed to limit the authority of the department to terminate or limit such authorization.

e. A CO_2 allowance shall not constitute a property right.

3. Allowances Available for Compliance Deduction (Env-A 4605.04)

   a. CO_2 allowances that meet the following criteria shall be available to be deducted for compliance with the requirements of Env-A 4605 for a control period:

      i. For CO_2 allowances other than CO_2 offset allowances, the allowances are from allocation years that fall within a prior control period or the same control period for which the allowances will be deducted; and

      ii. The CO_2 allowances are:

         1. Held in the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period; or
         2. Transferred into the compliance account by a CO_2 allowance transfer correctly submitted for recordation under Env-A 4608.01 by the CO_2 allowance transfer deadline for that control period;

   b. As provided in RSA 125-O:22, II, a CO_2 budget source may use offset allowances for up to 3.3 percent of its compliance obligation, subject to the following:

      i. If the Department determines that there has been a stage one trigger event, the CO_2 budget source may use offset allowances for up to 5 percent of its compliance obligation; and

      ii. If the Department determines that there has been a stage two trigger event, the CO_2 budget source may use offset allowances for up to 10 percent of its compliance obligation.

   c. CO_2 allowances shall not be available for current compliance if the allowances were deducted for excess CO_2 emissions for a prior control period under Env-A 4605.08.

   d. Allowances deducted for the purpose of compliance shall not be available for any other purpose.

4. Excess CO_2 Emissions Requirements (Env-A 4605.07)
   The Owner or Operator of a CO_2 budget source that has excess CO_2 emissions in any control period shall:

   a. Forfeit the CO_2 allowances required for deduction under Env-A 4605.08, provided CO_2 offset allowances shall not be used to cover any part of such excess CO_2 emissions; and

   b. Pay any fine, penalty, or assessment or comply with any other remedy imposed under RSA 125-O:22, V.

5. Deductions for Excess CO_2 Emissions (Env-A 4605.08)

   a. As provided by RSA 125-O:22, V, the deduction of CO_2 allowances for excess CO_2 emissions shall be equal to 3 times the number of the source's excess CO_2 emissions.

   b. Within 14 calendar days of receipt of notice from the regional organization[30] that a shortage exists, the source shall transfer sufficient allowances into its compliance account to cover the shortage.

   c. No CO_2 offset allowances shall be deducted to account for the source's excess CO_2 emissions.

   d. Any CO_2 allowance deduction required under 5.a, above, shall not affect the liability of the owner(s) and operator(s) of the CO_2 budget source or the CO_2 units at the source for any fine, penalty, or assessment, and shall not affect the obligation of the owner(s) and operator(s) to comply with any other remedy, for the same violation, as ordered under applicable state law.

6. Determination of Violations and Deduction of Allowances (Env-A 4605.11)

   a. For purposes of determining the number of days of violation, if a CO_2 budget source has excess CO_2 emissions for a control period, each day in the control period shall constitute a day of violation unless the owner(s) and operator(s) of the unit demonstrate that a lesser number of days should be considered; and

   b. Each ton of excess CO_2 emissions shall constitute a separate violation.

7. Submission of CO_2 Allowance Transfers (Env-A 4608.01)

   a. Any CO_2 AAR seeking recordation of a CO_2 allowance transfer shall submit the transfer request to the regional organization in accordance with Env-A 4608.01(b).

I. Monitoring/Testing Requirements

1. The Permittee is subject to the monitoring/testing requirements as contained in Table 7 below:

[30] Regional organization as defined in NH RSA 125-O:20, XIII

Table 7 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	MK1 & MK2	NOx Emissions	For MK1 and MK2, the owner or operator shall install, certify, operate and maintain, a NOx-diluent continuous emission monitoring system (consisting of a NOx pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NOx concentration (in ppm) averaged on an hourly and 24-hour calendar day basis, O_2 or CO_2 concentration (in percent O_2 or CO_2) and NOx mass emission rate (in lb/mmBtu) averaged on an hourly, 24-hour calendar day, and annual basis for each unit. The owner or operator shall account for total NOx emissions, both NO and NO_2, either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2. The owner or operator shall calculate hourly, quarterly, and annual NOx emission rates (in lb/mmBtu) by combining the NOx concentration (in ppm), diluent concentration (in percent CO_2), and percent moisture according to the procedures in 40 CFR 75 Appendix F.	Continuously	Env-A 808.02 (a) (new) and 40 CFR 75 § 75.10(a)(2), § 75.12, and Env-A 1211.03 (f)
2.	MK1, MK2, MKCT1, & MKCT2	NOx Mass Emissions	For MK1, MK2, MKCT1, and MKCT2, the owner or operator shall calculate hourly NOx mass emissions (in lbs) by multiplying the hourly NOx emission rate (in lbs/mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time. The owner or operator shall also calculate quarterly and cumulative year-to-date NOx mass emissions and (in tons) by summing the hourly NOx mass emissions according to the procedures in 40 CFR 75 Appendix F Section 8.	Hourly, quarterly, and cumulative year-to-date	40 CFR 75 §75.71, and §75.72 and Env-A 3212 and Env-A 2910
3.	MK1, MK2, MKCT1, & MKCT2	Ozone Season NOx Emission Rate and NOx mass emissions	The owner or operator shall determine the ozone season NOx emission rate (in lb/mmBtu) by dividing ozone season NOx mass emissions (in lbs) by heat input. The owner or operator shall also calculate cumulative NOx mass emissions for the ozone season (in tons) by summing the hourly NOx mass emissions according to the procedures in 40 CFR 75 Appendix F Section 8.	Hourly and at the end of the ozone season	Env-A 3212.01 and 40 CFR 75 §75.75(b) and §75.72

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
4.	MKCT1 & MKCT2	CO_2, SO_2, opacity monitoring, recordkeeping, and reporting exemptions	The requirements of 40 CFR 75 Subpart H for CO_2, SO_2, opacity monitoring, recordkeeping, and reporting do not apply to units that are subject to a State or Federal NOx mass emission reduction program only and are not affected units with an Acid Rain Program emission limitation (i.e., MKCT1 & MKCT2).	NA	40 CFR 75 §75.70(a)(2)
5.	MK1 & MK2	General CEM Requirements	A) Pursuant to 40 CFR 75.5 (b), the Permittee must operate MK1 and MK2 in compliance with the requirements of 40 CFR 75.2 through 75.75 and 40 CFR 75 Appendices A through I. B) Pursuant to 40 CFR 75.5 (d), the Permittee shall account for all emissions of SO_2, NOx, and CO_2 in accordance with 40 CFR 75.10 through 75.19. C) Pursuant to 40 CFR 75.5 (e), the Permittee shall not disrupt the continuous emission monitoring system or other approved emission monitoring method, and thereby not monitor or record SO_2, NOx, and CO_2, except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and 40 CFR 75 Appendix B. D) The CEMS shall meet the most stringent requirements of 40 CFR 75 and Env-A 808 (new).	Continuously	40 CFR 75 §75.5 and Env-A 808 (new)
6.	MK1 & MK2	CEMS Performance and Audit Requirements	The Permittee shall ensure that each CEMS meets the following requirements: A) Each CEMS meets equipment, installation, and performance specifications in 40 CFR 75 Appendix A; B) Each CEMS is maintained according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B; and C) Each CEMS shall record SO_2 and NOx emissions in the appropriate units of measurement. D) The permittee shall comply with the most stringent CEM audit requirements contained in 40 CFR 75 and Env-A 808.07, *General Audit Requirements*, Env-A 808.08, *Audit Requirements for Gaseous CEM Systems*, and Env-A 808.09, *Audit Requirements for Opacity CEM Systems.*	As specified by regulation	40 CFR 75 §75.10(b) and Env-A 808.07, 808.08, and 808.09 and 40 CFR 75 Appendices A and B

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
7.	MK1 & MK2	Valid Averaging Periods for Gaseous and Opacity CEM Systems	The number of hours of valid CEM data required for determining a valid averaging period for the different emission standard periods shall be: A) For a 3-hour emission standard period, 2 hours of valid data; B) For a 4-hour emission standard period, 3 hours of valid data; C) For an 8-hour emission standard period, 6 hours of valid data; D) For a 12-hour emission standard period, 9 hours of valid data, and E) For a 24-hour emission standard period, 18 hours of valid data.	As applicable	Env-A 808.14 (formerly Env-A 805.09)
8.	MK1 & MK2	SO_2 Emissions	The owner or operator shall install, certify, operate and maintain, an SO_2 CEMS automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm) averaged on an hourly and 24-hour calendar day basis, volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr averaged over one hour and each 24-hour calendar day, and tons/consecutive 12-month period and tons/calendar year) for each unit. The owner or operator shall also measure and record the SO_2 emission rate (in lb/mmBtu) averaged over each 24-hour calendar day. The owner or operator shall demonstrate compliance with the State Acid Rain Program emission caps by using the CEMS data.	Continuously	Env-A 808.02 (a)(1) (new) and 40 CFR 75 §75.10 (a)(1)
9	MK1 & MK2	CO_2 Emissions	The owner or operator shall install, certify, operate and maintain, a CO_2 CEMS automated data acquisition and handling system. The owner or operator shall measure and record CO_2 emissions in lb/hr over each 24-hour calendar day and CO_2 concentration in percent on an hourly average and over each 24-hour calendar day. The owner or operator shall use applicable procedures specified in 40 CFR 75 Appendix G to calculate CO_2 emissions. Please note that equation G-1 of 40 CFR 75 Appendix G shall not be used to determine CO_2 emissions under Env-A 4609.	Continuously	40 CFR 75 §75.10(a)(3), 40 CFR 75 Appendix G, & Env-A 4609

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
10.	MK1 & MK2	Heat input rate measurement	The owner or operator shall determine the heat input rate (in mmBtu/hr) to each unit for every hour or part of an hour any fuel is combusted following the procedures in 40 CFR 75 Appendix F.	Hourly	40 CFR 75 §75.10(c) Federally Enforceable & Env-A 2910.02
11.	MK1 & MK2	Stack Volumetric Flow Rate	The owner or operator shall install, certify, operate and maintain, a CEMS automated data acquisition and handling system to measure and record stack volumetric flow rate (in kscfm) on an hourly average and over each 24-hour calendar day.	Continuously	40 CFR 75 §75.10(a) & Env-A 2910.02
12.	MK1 & MK2	Stack Volumetric Flow Measuring Device	The owner or operator shall meet the following requirements for the stack volumetric flow measuring device: A) All differential pressure flow monitors shall have an automatic blow-back purge system installed and in wet conditions, shall have the capability for drainage of the sensing lines; and B) The stack flow monitoring system shall have the capability for manual calibration of the transducer while the system is on-line and for a zero check.	Continuously	Env-A 808.03(d)
13.	MK1 & MK2	Opacity	The owner or operator shall install, certify, operate and maintain, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) for each 6-minute period for each unit. When the COMS does not meet the minimum operating requirements, then the owner or operator shall also use US EPA Method 9 to estimate opacity.	Continuously	40 CFR 75 §75.10(a)(4) and Env-A 805.02 (old) and Env-A 808.02 (a) (new) and 807.02 (new)
14.	MK1, MK2, MKCT1, & MKCT2	Net Electrical Output	The owner or operator shall monitor and/or calculate net electrical output as reported to and publicly available from US Department of Energy, Energy Information Agency.	Annually	Env-A 2910.02, Env-A 3207.04, Env-A 3705and 40 CFR 75.53
15.	MK1, MK2, MKCT1, & MKCT2	Ozone Season Heat Input	The owner or operator shall calculate ozone season heat input for purposes of providing data needed for determining allocations by summing each unit's hourly heat input determined according to the procedures in 40 CFR 75 for all hours in which the unit operated during the ozone season	Hourly during ozone season	Env-A 3212.01 and 40 CFR 75 §75.75(a)

Table 7 - Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
16.	MK1 & MK2	CEM Hourly Operating Requirements & Valid Hour of CEM Data	Pursuant to Env-A 808.01, 808.03, and 40 CFR 75.10(d), the Permittee shall ensure that the CEMS and components meet the following hourly operating requirements: A) The Permittee shall ensure that each CEM is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval pursuant to Env-A 40 CFR 75.10(d) and pursuant to Env-A 808.03(c)(2) for each successive 5-minute period for gaseous emissions, unless a longer time period is approved in accordance with Env-A 809 B) The Permittee shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, CO_2 mass emissions (if applicable), NOx concentration, and NOx emission rate data collected by the monitors to hourly averages. C) The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. D) Failure of an SO_2 or CO_2 pollutant concentration monitor, NOx concentration monitor, flow monitor, or NOx-diluent CEMS to acquire the minimum number of data points for calculation of an hourly average shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. E) For a NOx-diluent monitoring system, an hourly average NOx emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the NOx pollutant concentration monitor and the diluent monitor (CO_2). F) If a valid hour of data is not obtained, the Permittee shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data.	Hourly	40 CFR 75 §75.10(d) and Env-A 808.01(i) and 808.03

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
16.	MK1 & MK2	CEM Hourly Operating Requirements & Valid Hour of CEM Data (continued)	G) Pursuant to Env-A 808.01(i), a valid hour of CEM emissions data means a minimum of 42 minutes of CEM readings taken in any calendar hour, during which the CEM is not in an out of control period and the facility is in operation. H) Pursuant to Env-A 808.03(a), the owner or operator shall average and record the CEM data for gaseous emissions for each calendar hour. I) Pursuant to Env-A 808.03(c)(1), all CEM systems shall include a means to display instantaneous values of percent opacity and gaseous emission concentrations.	Hourly	40 CFR 75 §75.10(d) and Env-A 808.01(i) and 808.03
17.	MK1 & MK2	COMS Hourly Operating Requirements	Pursuant to 40 CFR 75.10(d), the Permittee shall ensure that each COMS and components meet the following hourly operating requirements: A) The Permittee shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing (and recording pursuant to Env-A 808.03(c)(2) unless a longer time period is approved in accordance with Env-A 809) for each successive 10-second period and one cycle of data recording for each successive 6-minute period. B) The Permittee shall reduce all opacity data to 6-minute averages calculated in accordance with the provisions of 40 CFR 51 Appendix M, except where the SIP or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement. C) Pursuant to Env-A 808.03(b)(1), the owner or operator shall average the opacity data to result in consecutive, non-overlapping 6-minute averages; and D) Pursuant to Env-A 808.03(b)(2), the COMS must total number of minutes in any 8-hour period where the opacity, as averaged in non-overlapping 6-minute periods, exceeds the applicable opacity standard. E) Pursuant to Env-A 808.03(c)(1), all CEM systems shall include a means to display instantaneous values of percent opacity and gaseous emission concentrations.	Sampling for successive 10-second period and recording for successive 6-minute period	40 CFR 75 §75.10(d) and Env-A 808.03(b) and (c)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
18.	MK1 & MK2	Minimum measurement capability requirement	The Permittee shall ensure that each CEMS is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in 40 CFR 75 Appendix A Sections 2.1.1.5, 2.1.2.5, and 2.1.4.3.	As specified by regulation	40 CFR 75 §75.10(f)
19.	MK1 & MK2	Specific provisions for monitoring SO_2 emissions (SO_2 emissions and flow monitors)	The owner or operator shall meet the general operating requirements in 40 CFR 75.10 for an SO_2 continuous emission monitoring system and a flow monitoring system.	As specified by regulation	40 CFR 75 §75.11(a), (b)
20.	MK1 & MK2	Specific provisions for monitoring NOx emissions – Coal-fired Units	A) Pursuant to 40 CFR 75.12, 75.71, and 75.72 and Env-A 3212, the Permittee shall meet the specific provisions for NOx-diluent CEMS, including the following: 1) Meet general operating requirements in 40 CFR 75.10 for a NOx continuous emission monitoring system. The diluent gas monitor in the NOx CEMS may measure either O_2 or CO_2 concentration in the flue gases. 2) Comply with moisture correction procedures according to 40 CFR 75.12(b) 3) Comply with NOx emission rate procedures contained in 40 CFR 75.12(c). B) The Permittee shall meet the annual and ozone season monitoring requirements according to 40 CFR 75.74, as applicable.	Continuously	40 CFR 75 §75.12, 75.71, and 75.72 and Env-A 3212

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
21.	MKCT1 & MKCT2	NOx Mass Emissions - Specific Provisions for Monitoring NOx Emissions for Alternative Monitoring System	The owner or operator shall meet the requirements of 40 CFR 75.12 including using the procedures of 40 CFR 75 Appendix E for estimating hourly NOx emission rate, using the procedures of 40 CFR Appendix D for determining hourly heat input, except for the heat input apportionment provisions of 40 CFR 75 Appendix D Section 2.1.2 to meet the NOx mass reporting provisions. If in the years after certification of the monitoring system, a unit's operation exceed a capacity factor of 20 percent in any calendar year or exceed a capacity factor of 10.0 percent averaged over three years, or exceed a capacity factor of 20.0 percent in any ozone season or exceed an ozone season capacity factor of 10.0 percent averaged over three years, the owner or operator shall install, certify, and operate a NOx CEMS and also meet the requirements of 40 CFR 75.71(c) no later than December 31 of the following calendar year.	Hourly	40 CFR 75 Appendix E Section 1.1 and 40 CFR 75 §75.12(d)(2) and 75.71(d)
22.	MK1 & MK2	Specific provisions for monitoring CO_2 emissions	The owner or operator shall comply with the applicable CO_2 monitoring provisions of 40 CFR 75 §75.13(a), (b), and (c) for the CO_2 CEMS and flow monitoring systems.	Continuously	40 CFR 75 §75.13(a)-(c)
23.	MK1 & MK2	Specific provisions for monitoring opacity	Pursuant to 40 CFR 75.14, the continuous opacity monitoring and recording system shall meet all the design, installation, equipment, and performance specifications of 40 CFR 60, Appendix B, Performance Specification 1, and all the operational and quality assurance requirements of Env-A 808 (new).	Continuously	40 CFR 75 §75.14 and Env-A 808 (new)
24.	MK1 & MK2	Reference Test Methods for Certification or Re-certification of CEMS or COMS	The Permittee shall use the reference test method listed in 40 CFR 75.22 and included in Appendix A to 40 CFR 60 to conduct monitoring system tests for certification or recertification of CEMS and expected monitoring systems under 40 CFR 75 Appendix E and quality assurance and quality control procedures.	During certification and recertification tests	40 CFR 75 §75.22

Table 7 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
25.	MK1 & MK2	Out of control periods	A) Pursuant to 40 CFR 75.21(e)(2), whenever a CEMS or COMS fails a quality assurance audit or any other audit, the system is out-of-control, and the Permittee shall follow the procedures for out-of-control periods in 40 CFR 75.24. B) Pursuant to Env-A 3212.10 and 2910.06, whenever any monitoring system fails to meet the quality assurance requirements of 40 CFR 75 Appendix B, the permittee shall substitute the data using the applicable procedures in 40 CFR 75, Subpart D, Appendix D or E. C) Pursuant to 75.24, if an out-of-control period occurs to a monitor or CEMS, the owner or operator shall take corrective action and repeat the tests applicable to the out of control parameter as described in 40 CFR 75 Appendix B. 1) For daily calibration error tests, an out of control period occurs when the calibration error of a pollutant concentration monitor exceeds 5.0% based upon the span value, the calibration error of a diluent gas monitor exceeds 1.0% O_2 or CO_2, or the calibration error of a flow monitor exceeds 6.0% based upon the span value, which is twice the applicable specification in 40 CFR 75 Appendix A. 2) For quarterly linearity checks, an out of control period occurs when the error in linearity at any of the three gas concentrations (low, mid-range, and high) exceeds the applicable specification in 40 CFR 75 Appendix A. 3) For relative accuracy test audits (RATAs), cylinder gas audit (CGAs), and relative accuracy audits (RAAs), an out of control period occurs when the sampling is completed and the CEMS fails the accuracy criteria until successful completion of the same audit after corrective action has occurred.	As specified by regulation	40 CFR 75 §75.21(e)(2) and 75.24 and Env-A 3212.10 and 2910.06 and 808.01(g)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
25.	MK1 & MK2	Out of control periods (continued)	D) Pursuant to Env-A 3212.10, whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement pursuant to Env-A 800 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department shall issue a notice of disapproval of the certification status of such system or component. E) For the purposes of this section, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. F) The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the disapproval of certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests in accordance with Env-A 3212.07(t). G) The owner or operator shall follow the initial certification or recertification procedures for each disapproved system.	As specified by regulation	40 CFR 75 §75.21(e)(2) and 75.24 and Env-A 3212.10 and 2910.06 and 808.01(g)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
26.	MK1 & MK2	Out of Control Periods for Opacity	Out of control period for a CEMS measuring opacity is as follows: A) The time period beginning with the completion of the daily calibration drift (CD) check where the CD exceeds 2% opacity for 5 consecutive days, and ending with the CD check after corrective action has occurred that results in the performance specification drift limits being met; B) The time period beginning with the completion of a daily CD check preceding the daily CD check that results in the CD being greater than 5% opacity and ending with the CD check after corrective action has occurred that results in the performance specification drift limits being met; or C) The time period beginning with the completion of a quarterly opacity audit where the CEMS fails the calibration error test as specified in 40 CFR 60, Appendix B, Specification 1 and ending with successful completion of the same audit where the CEMS passes the calibration error test established after corrective action has occurred.	As specified by regulation	Env-A 808.01(g)(2)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
27.	MK1, MK2, MKCT1 & MKCT2	Data Availability and Missing Data Substitution Procedures	A) The Permittee shall follow the procedures in 40 CFR 75.30 through 75.37, 75.70(f), 75.74, and 40 CFR 75 Appendix E when a valid, quality-assured hour of data is not measured or recorded. B) For MKCT1 & MKCT2, the Permittee shall provide substitute data pursuant to 40 CFR 75.74 and 40 CFR 75 Appendix E Section 2.5, when the QA/QC control parameters are exceeded or missing. C) Pursuant to Env-A 808.02(c)(2), the permittee shall comply with the minimum percentage data availability requirements pursuant to Env-A 808.10(a)-(d) to meet the requirements of Env-A 3200, *NOx Budget Program*. D) Pursuant to Env-A 808.10, if the permittee cannot meet the percentage data availability requirements, the permittee shall also follow the provisions of Env-A 808.10(e) – (g). E) Pursuant to 40 CFR 75.24(e), if COMS is out of control, the permittee shall follow the data availability requirements of Env-A 808.10.	As specified by regulation	40 CFR 75 §75.30 through 75.37 and 75.50(f) and 75.24(e) and 75.74 and 40 CFR 75 Appendix E Section 2.5 & Env-A 808.10 & 808.02(c)(2)
28.	MK1, MK2, MKCT1 & MKCT2	NOx Mass Emissions - General Provisions	A) Pursuant to Env-A 3200, *NOx Budget Program*, the permittee shall comply with the provisions of 40 CFR 75 Subparts A, C, D, E, F, and G and Appendices A through G applicable to NOx concentration, flow rate, NOx emission rate and heat input, as set forth and referenced in Subpart H. B) The requirements of Subpart H for CO_2, SO_2, opacity monitoring, recordkeeping, and reporting do not apply to units that are subject to a State or federal NOx mass emission reduction program only and are not affected units with an Acid Rain Program emission limitation (i.e., MKCT1 & MKCT2).	As specified by regulation	Env-3212.01 and 40 CFR 75 §75.70(a)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
29.	MK1, MK2, MKCT1, MKCT2	NOx Mass Emissions Provisions - Prohibitions	A) No owner or operator of an affected unit shall use any alternative monitoring system, reference method, or any other alternative for the required CEMS without approval through petition process in § 75.70(h). **(MKCT1 and MKCT2 did get approval of use of Appendix E.)** B) No owner or operator of an affected unit shall operate the unit so as to discharge NOx emissions without accounting for all emissions in accordance with the provisions of Subpart H, except as provided in § 75.74. C) No owner or operator of an affected unit shall disrupt the CEMS or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass emissions, except for periods of re-certification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of Subpart H applicable to the monitoring systems under § 75.71, except as provided in § 75.74. D) No owner or operator of an affected unit shall retire or permanently discontinue use of the CEMS, or any other approved emission monitoring system except under one of the following circumstances: 1) During period that the unit is covered by a retired unit exemption that is in effect under the State or federal NOx mass emission reduction program that adopts the requirements of Subpart H; 2) The owner or operator is monitoring NOx emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of § 75.70(d); or 3) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.61. E) The owner or operator shall use the alternative monitoring provisions of 40 CFR 75 Appendix E for determining NOx emissions for MKCT1 and MKCT2.	Continuously	40 CFR 75 §75.70(c) and 40 CFR 75 Appendix E

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
30.	MK1, MK2, MKCT1, MKCT2	CEMS and COMS and Alternative Monitoring Certification	Pursuant to 40 CFR 75.20 and 40 CFR 75.70(d) and Env-A 3212.07 and Env-A 3212.10, the Permittee shall recertify the CEMS and COMS and alternative monitoring system whenever the Permittee makes a replacement, modification, or change to the systems or to the facility that could significantly affect the ability of the systems to accurately measure and record the requisite data. The Permittee must submit an application for recertification of the monitoring system to EPA and DES, except pursuant to Env-A 3212.11, notifications for MKCT1 & MKCT2 shall only be sent to DES.	Whenever the Permittee makes a replacement, modification, or change to the systems or to the facility that could significantly affect the ability of the systems to accurately measure and record the requisite data	40 CFR 75 §75.20, 75.70(d), and 40 CFR 75 Appendix E Section 1.2 and Env-A 809, 3212.02, 3212.06, 3212.07, 3212.09, 3212.10 and 2910.04
31.	MK1 & MK2	QA/QC Requirements	A) Pursuant to 40 CFR 75.21 (a)(1) and 40 CFR 75.70, the Permittee shall operate, maintain, and calibrate each CEMS according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B. B) Pursuant to 40 CFR 75.21(b), the Permittee shall operate, calibrate, and maintain each COMS according to the procedures specified in the SIP, pursuant to 40 CFR 51 Appendix M. C) Pursuant to 40 CFR 75.21(c), the Permittee shall ensure that all calibration gases used to quality assure the operation of the instrumentation shall meet the definition in 40 CFR 72.2. D) Pursuant to 40 CFR 75.21(d) and (e), the Permittee shall comply with the provisions concerning consequences of audits and audit decertification. E) Within and prior to the ozone season, the Permittee shall meet the quality assurance requirements contained in 40 CFR 75.74, as applicable.	As specified by regulation	40 CFR 75 §75.21, 75.70, and 75.74
32.	MKCT1 & MKCT2	QA/QC Requirements for Alternative Monitoring Systems	The owner or operator shall comply with the QA/QC procedures of 40 CFR 75 Appendix E and 40 CFR 75.74(c), as applicable. Pursuant to 40 CFR 75.74(b), the owner or operator may choose whether to meet the QA/QC requirements on an annual basis or an ozone season basis.	Annually or ozone season basis	40 CFR 75 §75.70(e) and 40 CFR 75 Appendix E and 40 CFR 75 §75.74(b) and (c)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
33.	MKCT1, MKCT2, MK1 & MK2	NOx Mass Emissions – Petitions for Alternatives	The owner or operator may submit a petition to DES and EPA requesting an alterative to any requirement of 40 CFR 75 Subpart H. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by Env-A 3200 or other applicable State or Federal NOx mass emission reduction program that adopts the requirements of 40 CFR 75 Subpart H. Pursuant to 40 CFR 75.70(h)(3)(i), the owner or operator filed a petition for an alternate monitoring method for MKCT1 and MKCT2 using Appendix E, which was approved by the USEPA and DES.	Upon request by permittee	40 CFR 75 §75.70(h) and 40 CFR 75 Subpart E and 40 CFR 75 Appendix E & Env-A 3212.09
34.	MKCT1, MKCT2	NOx Mass Emissions-Alternative Monitoring System	The owner or operator shall comply with the provisions of 40 CFR 75 Appendix E and Env-A 3212.09 as an alternative to continuous emission monitoring system requirements.	During the ozone season	40 CFR 75 Appendix E and Env-A 3212.09
35.	MKCT1, MKCT2	NOx Mass Emissions – NOx Emission Rate and Heat Input– Oil-fired Peaking Units	The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired shall either: A) Meet the requirements of 40 CFR 75.71(c); or B) Use the procedures in 40 CFR 75 Appendix D for determining hourly heat input and the procedure specified in 40 CFR 75 Appendix E for estimating hourly NOx emission rate. The heat input apportionment provisions in Section 2.1.2 of Appendix D shall not be used to meet the NOx mass reporting provisions of Subpart H. In addition, if after certification of an excepted monitoring system under Appendix E, the operation of a unit that reports emissions on an annual basis under 40 CFR 75.74(a) exceeds a capacity factor of 20.0 percent in any calendar year or exceeds an annual capacity factor of 10.0 percent averaged over 3 years, or the operation of a unit that reports emissions on an ozone season basis under 40 CFR 75.74(b) exceeds a capacity factor of 20.0 percent in any ozone season or exceeds an ozone season capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of 40 CFR 75.71(c) or, if applicable 40 CFR 75.71(e) by no later than December 31 of the following calendar year.	As specified by regulation	40 CFR 75 §75.71(d)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
36.	MK1, MK2, MKCT1, MKCT2	NOx Mass Emissions – Annual and Ozone Season Monitoring	The owner or operator shall meet the requirements of 40 CFR 75 Subpart H during the entire calendar year for MK1 and MK2 and on an ozone season basis except as specified for MKCT1 & MKCT2.	During the calendar year for MK1 and MK2 and during the ozone season for MKCT1 & MKCT2	40 CFR 75 §75.74(a) and (b)
37.	MKCT1 & MKCT2	NOx RACT Compliance Testing	The owner or operator shall conduct stack testing using US EPA Method 20 to determine the NOx emissions. The owner or operator shall monitor the NOx emissions by calculating the NOx emission rate in lb/MMBtu on a 24-hour calendar day average, lb/hr on a 24-hour calendar day average, and tons/consecutive 12-month period using the stack test results and actual operating hours.	Once every 3 years and upon written request by DES and/or EPA	Env-A 1211.13(f) Env-A 803.02(c) (formerly Env-A 1211.21) and 40 CFR 70.6 (a)(3)(i)(B)
38.	MK1 & MK2	Ammonia slip testing	The owner or operator shall conduct stack testing at a NOx emission rate, in lb/MMBtu, as specified by DES, using a DES-approved method to determine the ammonia slip.	At least once every 5 years or upon request by DES and/or EPA	40 CFR 70.6 (a)(3)(i)(B)
39.	MK1-PC3 & MK2-PC6	Ammonia Consumption	The owner or operator shall track ammonia consumption daily and monthly using an ammonia flow meter installed with the SCR systems.	Daily and monthly	Temporary Permits FP-T-0054 & TP-B-0462
40.	MK1-PC1, MK1-PC2, MK2-PC4 & MK2-PC5	# of Fields Out of Service for each ESP unit	The owner or operator shall monitor on a daily basis the total number of fields out of service for each electrostatic precipitator.	Daily	40 CFR 70.6(a)(3)(i)(B)
41.	MK1-PC1, MK1-PC2, MK2-PC4 & MK2-PC5	Inlet gas temperature to each ESP	The owner or operator shall continuously monitor the outlet gas temperature of the ESP using a DES-approved monitoring system to ensure that the ESP does not exceed the manufacturer's recommended temperature.	Continuously	40 CFR 70.6 (a)(3)(i)(B)
42.	Facility Wide	Sulfur Content of Liquid Fuels	PSNH shall conduct testing in accordance with appropriate ASTM test methods or obtain delivery tickets or other documentation from the fuel supplier to demonstrate compliance with the liquid fuel sulfur content limitations.	For each delivery of liquid fuel to the facility	Env-A 806.02, Env-A 806.05, 40 CFR 60 Subpart Dc §60.42c(h)(1), §60.48c(f)(1), & §60.44c(h)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
43.	MK1 & MK2	Sulfur Content of Bituminous Coal	Documentation from the fuel supplier or testing in accordance with appropriate ASTM test methods that certify the weight-percent of sulfur for each delivery of bituminous coal	Each delivery of fuel	Env-A 806.04
44.	MKCT1, MKCT2, MKSCC, MKEG, MKEB	Opacity	USEPA Method 22 for visible emissions. If noticeable opacity is observed, USEPA Method 9	Monthly when the device is operating	40 CFR 70.6 (a)(3)(i)(B)
45.	MKEG	Operating Hours	The owner or operator shall maintain a log of the operating hours of the emergency generator.	Continuously	40 CFR 70.6 (a)(3)(i)(B)
46.	MKPCC & MKSCC	Coal Throughput	The owner or operator shall maintain records of the monthly coal received and coal burned (coal throughput).	Monthly	40 CFR 70.6 (a)(3)(i)(B) & State Permits to Operate No. PO-BP-2416 & 2417
47.	MK1 & MK2	Coal Feed Rate - Periodic Monitoring	E Belt scales for MK1 and MK2 shall be verified or calibrated once per year.	Annually	40 CFR 70.6 (a)(3)(i)(B)
48.	MK1 & MK2	TSP Testing	The owner or operator shall conduct stack testing using US EPA Methods 1-5 or 1-4 and 17 or other method approved by DES to determine the TSP emissions. The owner or operator shall monitor the TSP emissions by calculating the TSP emission rate in lb/MMBtu on a 24-hour calendar day average and tons/consecutive 12-month period using stack test results and operating hours. The owner or operator may use other EPA-approved emission calculating methods to calculate TSP emissions.	Testing at least once every 5 years and upon request by DES and/or EPA	Env-A 802 & 40 CFR 70.6 (a)(3)(i)(B)
49.	MK1 & MK2	PM_{10} Testing	The owner or operator shall conduct stack testing using US EPA Method 201a and 202, or other method approved by DES to determine PM_{10} emissions. The owner or operator shall monitor the PM_{10} emissions by calculating the PM_{10} emission rate in tons/consecutive 12-month period using stack test results and operating hours. The owner or operator may use other EPA-approved emission calculating methods to calculate PM_{10} emissions.	Testing at least once every 5 years and upon request by DES and/or EPA	Env-A 802 & 40 CFR 70.6 (a)(3)(i)(B)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
50.	MKEB	Performance Test	Each time the owner or operator brings an Emergency Boiler into the facility for operation, it is required to conduct an initial performance test as required by 40 CFR 60.8 for opacity, within 60 days of achieving maximum production rate or within 180 days of initial startup. Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions. Testing will be conducted at the maximum permitted operating rate, 520 gal/hr while firing No. 2 fuel oil, or 701 gal/hr while firing on-road low sulfur diesel fuel.	Prior to the removal of Each Emergency Boiler installed	40 CFR 60 Subpart Dc §60.45c(a) & Env-A 802
51.	MKEB	Fuel flow meter, recorder, & totalizer	A) PSNH shall monitor or measure fuel oil consumption of MKEB (in gallons per hour and total gallons per day) using a fuel flow meter. B) PSNH shall calibrate or verify the accuracy of the fuel flow meter in accordance with the manufacturers or suppliers recommendation or in a manner approved by DES at a frequency consistent with the manufacturers or suppliers recommendation, but at a minimum annually.	Continuously	Temporary Permit TP-B-0490
52.	Facility wide	Inventories of Regulated Substances	The owner or operator shall monitor the quantity of regulated substances to ensure that the facility is in compliance with the requirements of 40 CFR 68.	Continuously	40 CFR 68 and 1990 CAA Section 112(r)(1)

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
53.	MK1 & MK2	Baseline Mercury Input	Baseline mercury input shall be determined as follows: A) No later than August 1, 2006, and continuing for 12 months thereafter, a representative monthly sample of the coal used traditionally (not to include trial or test coal blends) by each affected source shall be collected from each of the units identified in b. below and analyzed to determine the average mercury content of the fuel for each unit expressed in pounds of mercury input per ton of coal combusted at each affected source. The mercury content of the coal derived from these analyses for each affected source shall be multiplied by the average annual throughput of coal for the period 2003, 2004, and 2005 (average tons of coal combusted per year) for each respective affected source to yield the average pounds of mercury input per year into each affected source. The sum of these annual input pound averages from each affected source shall equal the baseline mercury input. B) Determination of the mercury content of the coal shall follow appropriate ASTM testing procedures (ASTM D3684-01). For purposes of baseline mercury input determination, coal sampling shall occur at Merrimack Unit 1 and Unit 2, and at either Schiller Unit 4 or Unit 6, which shall serve to represent all Schiller units. At least 4 of the samples taken from each of these units shall correspond with the stack testing done at each of these units under RSA 125-O:14,II.	As specified	RSA 125-O:14,I. (State-Only Enforceable)
54.	MK1 & MK2	Baseline Mercury Emissions	A) Pursuant to RSA 125-O:14,II, baseline mercury emissions shall be determined based upon stack testing and DES approval.	As specified in statute	RSA 125-O:14,II. (State-Only Enforceable)
55.	MK1 & MK2	Mercury Emission Monitoring	A) Prior to the availability and operation of CEMS, and subsequent to the baseline emissions testing under RSA 125-O:14, II, stack tests or another methodology approved by DES shall be conducted twice per year to determine mercury emissions levels from the affected sources.	Twice per year or until a mercury CEMS is in operation and approved by DES	RSA 125-O:15

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			B) Any stack tests performed shall employ a federally recognized and approved methodology, proposed by the Owner and employing a test protocol approved by DES. When a federal performance specification takes effect and a mercury CEMS capable of meeting the federal specifications becomes available, a mercury CEMS, approved by DES, shall be installed on MK1 and MK2 as deemed appropriate by DES.		
56.	MK2	SO_2, NOx,[31] CO, PM, VOCs Emissions (tons/month and tons/ consecutive 12-month period)	Pursuant to the 40 CFR 52.21 (b)(21)(v) (dated July 1, 2002)[32], for an electric utility steam generating unit (other than a new unit or the replacement of an existing unit), actual SO2, NOx, CO, PM, VOC emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided PSNH maintains and submits to DES on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by DES, if it determines such a period to be more representative of normal source post-change operations. Pursuant to 40 CFR 52.21(b)(33) (dated July 1, 2002), representative actual annual emission means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after the physical change or change in the method of operation of a unit (or a different consecutive two-year period within 10 years after that change, where DES determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions, DES shall consider all relevant information, including	Monthly	40 CFR 70.6 (a)(3)(i)(B) and 40 CFR 52.21 (b)(21) and (33), dated July 1, 2002

[31] SO_2 and NOx emissions are monitored based upon CEM data and CO, PM, and VOC emissions are calculated using emission factors and fuel data.

[32] See the letter dated January 31, 2008 from William H. Smagula, PSNH to Robert R. Scott, DES-Air Resources Division and the letter March 31, 2008 from Craig A. Wright, DES-Air Resources Division to William H. Smagula, PSNH concerning conditional new source review applicability determination concerning modifications at PSNH-Merrimack Station.

Table 7 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under Title IV of the CAA; and exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole. In order to calculate annual emissions as required pursuant to 40 CFR 52.21 (dated July 1, 2002), PSNH shall monitor emissions of SO2, NOx, CO, PM, and VOCs for a period of 5 years or more beginning in 2002.		
57.	MKEB	NOx, SO2, CO, PM10, and VOC emissions	PSNH shall monitor the NOx, SO2, CO, PM10, and VOC emissions (in tons/ consecutive 12-month period) by using appropriate AP-42 emission factors and actual fuel consumption.	Monthly and consecutive 12-month period	40 CFR 70.6 (a)(3)(i)(B)
58.	Facility-wide	Stack Test	For any compliance stack test, the owner or operator must meet the stack testing requirements of Env-A 802, including but not limited to pre-test meeting, pre-test protocol, pre-test notice, scheduling change notifications, and stack test result submittals	For each compliance stack test	Env-A 802

J. Recordkeeping Requirements

The Permittee is subject to the Recordkeeping requirements as contained in Table 8 below:

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
1.	Record Retention: A) The Permittee shall retain the records required by this permit on file for a minimum of 5 years, except the certificate of representation for the designated representatives shall be kept beyond the 5-year period.[34] B) Pursuant to Env-A 4605.03(a), unless otherwise provided, the Owner or Operator of the CO_2 budget source and each CO_2 budget unit at the source shall keep on site each of the following documents for a period of 10 years from the date the document is created: 1) The account certificate of representation for the CO_2 AAR for the source and each CO_2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation prepared in accordance with Env-A 4604.05, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO_2 AAR; 2) All emissions monitoring information, in accordance with Env-A 4609 and 40 CFR 75; 3) Copies of all reports, compliance certifications and other submissions and all records made or required under Env-A 4600; and 4) Copies of all documents used to complete a CO_2 budget permit application and any other submission under the CO_2 Budget Trading Program	Minimum of 5 year retention of records as specified	Facility Wide	40 CFR §72.9(f)(1), 40 CFR §75.57, 40 CFR 70.6(a)(3)(ii)(B), Env-A 3213, Env-A 902.01(a)(new), and Env-A 4605.03(a)

[33] On April 23, 1999 DES promulgated new Env-A 900 rules to streamline the recordkeeping and reporting requirement sections of the New Hampshire Code of Administrative Rules. Until such time that the new Env-A 900 rules are approved and adopted into the State Implementation Plan (SIP) by EPA, all Title V permits will be incorporating the old Env-A 900 rules (which became effective on November 11, 1992), unless the new Env-A 900 rules are more stringent. These recordkeeping and reporting requirements shall fall under the Permit Shield provisions as contained in Section XIII of this permit.

[34] Note that the record retention requirement for five years contained in Env-A 902.01 and Env-A 3213 are more stringent than the three year record retention required in some sections of 40 CFR 75.

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
	or to demonstrate compliance with the requirements of Env-A 4600.			
2.	<u>Monitoring Plan and QA/QC Plan:</u> A) The Permittee shall prepare and maintain a monitoring plan for the CEMS and COMS, which contains sufficient information to demonstrate that all unit SO_2 emissions, NOx emissions, CO_2 emissions and opacity are monitored and reported. B) The Permittee shall prepare and maintain monitoring plans for other approved monitoring methods, which contain sufficient information to demonstrate that all unit NOx emissions are monitored and reported. C) The Permittee shall update the monitoring plan whenever the Permittee makes a replacement, modification or change that could affect the CEMS or COMS or other approved monitoring method. D) The Permittee shall review the QA/QC plan and all data generated by its implementation at least once each year. E) The Permittee shall revise or update the QA/QC plan based on the results of the annual review by conducting the following: 1) Documenting any changes made to the CEM or the monitoring method or changes to any information provided in the monitoring plan; 2) Including a schedule of, and describing, all maintenance activities that are required by the CEM manufacturer or that might have an effect on the operation of the system; 3) Describing how the audits and testing required by this part will be performed; and 4) Including examples of the reports that will be used to document the audits and tests required by this part; 5) Make the revised QA/QC plan available for on-site review by the division at any time; and 6) Within 30 days of completion of the annual QA/QC plan review, certify in writing that the owner or operator will continue to implement the source's	Whenever a change occurs that could affect monitoring method or annually, whichever is more frequent	MK1 & MK2, MKCT1& MKCT2	40 CFR §75.53 (a), (b), (e), and (f), §75.73(c), Env-A 808.04, Env-A 808.06, Env-A 3212.13, and Env-A 2910.09

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	existing QA/QC plan or submit in writing any changes to the plan and the reasons for each change. F) The QA/QC plan shall be considered an update to the CEM monitoring plan required by Env-A 808.04. G) Pursuant to Env-A 3212.13(a) and Env-A 2910.09, the units subject to acid rain emission limitations (MK1 & MK2) shall comply with the requirements of 40 CFR 75.62, except the monitoring plan shall also include all of the information required by 40 CFR 75, Subpart H. H) Pursuant to Env-A 3212.13(b), a unit not subject to acid rain emission limitations (MKCT1 & MKCT2) shall comply with the requirements of 40 CFR 75.62, except the monitoring plan shall only include the information required by 40 CFR 75, Subpart H. I) Pursuant to 40 CFR 75.73(c)(3), the monitoring plan for a unit not subject to acid rain emission limitations (MKCT1 & MKCT2) shall include the provisions of 40 CFR 75.53(e)(1), 75.53(f)(1)(i), (f)(2)(i), and (f)(4) in electronic format and 40 CFR 75.53(e)(2), 75.53(f)(1)(ii), and (f)(2)(ii) in hardcopy format. J) For MK1 and MK2, the owner or operator shall determine the heat input rate (in mmBtu/hr) to each unit for every hour or part of an hour any fuel is combusted following the procedures in 40 CFR 75 Appendix F, Equation F-15 or other method approved by DES.			
3.	<u>CEM, COMS and Other Approved Monitoring Methods Recordkeeping Requirements:</u> A) The Permittee shall record and maintain the information required pursuant to 40 CFR 75.57, 75.58, 75.59, and 75.73(b), which includes the certification, quality assurance, and quality control records. B) The Permittee shall record and maintain CEMS and COMS records according to the most stringent requirements of Env-A 808 and 40 CFR 75.	As specified by regulation	MK1, MK2, MKCT1, MKCT2	40 CFR §75.57, 75.58,75.59, and 75.73, Env-A 3212, Env-A 903.04 (a) (new), and Env-A 800
4.	<u>Sulfur Analysis Records for Liquid Fuel Oil</u> The owner or operator shall maintain fuel	For each delivery of liquid fuel to the	MK1, MK2, MKCT1,	Env-A 806.05 (new) and

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
	delivery tickets for each shipment of fuel oil receeved. The deliver tickets shall be in a form suitable for inspection and available to the DES and/or EPA upon request. Each delivery ticket shall indicate the following: A) The name, address and telephone number of the fuel supplier; B) The type of fuel delivered; C) The quantity of fuel oil delivered; D) The date of delivery; and E) The maximum percent sulfur by weight of the fuel oil delivered. If the delivery tickets do not contain sulfur content of fuel delivered, the Permittee shall provide other documentation from the fuel supplier with the above information or a written statement or other documentation from the fuel supplier that the sulfur content of the fuel as delivered does not exceed state or federal standards for that fuel or perform testing in accordance with appropriate ASTM test methods to determine compliance with the sulfur content limitation provisions in Env-A 1604 for liquid fuel.	facility	MKCT2, MKEB, MKEG	40 CFR 70.6(a)(3)(ii)(A) and 40 CFR 60 Subpart Dc §60.48c(f)(1) (for MKEB)
5.	<u>Delivery Ticket and Sulfur Analysis Records for Coal:</u> The permittee shall maintain delivery tickets from each coal supplier for each shipment of coal received. The delivery tickets shall be in a form suitable for inspection and available to the DES and/or EPA upon request. Each delivery ticket shall indicate the following: A) The name of the fuel supplier; B) The address of the fuel supplier; C) The telephone number of the fuel supplier; D) The type of fuel delivered; E) The quantity of coal delivered; F) The date of delivery; G) The maximum percent sulfur by weight of the coal delivered or the lb sulfur/MMBtu of coal; H) Identification of the mine from which the coal originated; I) The weight percent ash content of the coal; and J) The gross heat content of the coal (Btu per pound). If the delivery tickets do not contain sulfur	Each delivery of Coal	MK1 & MK2	Env-A 806.05 (new) & 40 CFR 70.6(a)(3)(ii)(A)

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	content of fuel delivered, the Permittee shall provide other documentation from the fuel supplier with the above information or perform testing in accordance with appropriate ASTM test methods to determine compliance with the sulfur content limitation provisions in Env-A 1606 for solid fuels.			
6.	Solid Fuel Utilization Records: The Permittee shall maintain the following monthly records or records for an alternative period as approved by DES in accordance with Env-A 912, of the bituminous coal characteristics and utilization: A) Fuel consumption; B) Fuel type; C) Ash content; D) Sulfur content as percent sulfur by weight of fuel and pounds per million Btu gross heat content; and E) Btu content per pound of fuel.	Monthly or alternative period as approved by DES in accordance with Env-A 912	MK1 & MK2	Env-A 903.03(a)(1) (formerly Env-A 901.03(a)(2))
7.	Liquid Fuel Utilization Records: The Permittee shall maintain the following monthly records or records for an alternative period as approved by DES in accordance with Env-A 912, of the liquid fuel characteristics and utilization by device: A) Fuel consumption; B) Fuel type; C) Viscosity (based on generally accepted values); D) Sulfur content as percent sulfur by weight of fuel; E) Btu content per gallon of fuel; and F) Hours of operation of each fuel combustion device while operating with each type of liquid fuel, so the distribution of fuel among each combustion device can be estimated.	Monthly or alternative period as approved by DES in accordance with Env-A 912	MK1, MK2, MKCT1, MKCT2, MKEB, MKEG	Env-A 903.03(a)(3) and (b) (formerly Env-A 901.03(a)(1) and (c))
8.	General Recordkeeping Requirements for Process Operations: Keep monthly records of raw material utilization (coal) for each of the crusher systems and coal fed to MK1 and MK2.	Monthly and consecutive 12 month periods	MKPCC, MKSCC, MK1, MK2	Env-A 903.02 & State Permits to Operate PO-BP-2416 & PO-BP-2417

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
9.	General NOx Recordkeeping Requirements: The Permittee shall record and maintain the following information for fuel burning devices: A) Facility information, including the following: 1) Source name; 2) Source identification; 3) Physical address; and 4) Mailing address. B) Identification of fuel burning devices; C) Operating schedule for each fuel burning device identified in Condition B) above: 1) Days per calendar week during the normal operating schedule; 2) Hours per day during the normal operating schedule and for a typical ozone season day; and 3) Hours per year during the normal operating schedule. D) Type and amount of fuel burned for each fuel-burning device during normal operating conditions and for a typical ozone season day, if different from normal operating conditions, on an hourly basis in mmBtu/hr. E) Theoretical potential NOx emissions for the calculation year for each fuel burning device: 1) Annual emissions, in tons per year; and 2) Typical ozone season day emissions, in pounds per day. F) Actual NOx emissions for each fuel burning device: 1) Annual emissions, in tons per year; and 2) Typical ozone season day emissions, in pounds per day. G) Emission factors and the origin of the emission factors used to calculate the NOx emissions.	Annually and as applicable	MK1, MK2, MKCT1, MKCT2, MKEB, MKEG	Env-A 905.02 (formerly Env-A 901.08(c)(1)-(5))

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
10.	<u>Recordkeeping Requirements for Sources or Devices with Add-On NOx Air Pollution Control Equipment:</u> The Permittee shall record and maintain the following information: A) Air pollution control device identification number, type, model number, and manufacturer; B) Installation date; C) Unit(s) controlled; D) Type and location of the capture system, capture efficiency percent, and method of determination; E) Emission test results, including inlet NOx concentration (ppm), outlet NOx concentration (ppm), method of concentration determination, and date of determination; F) Information as to whether the air pollution control device is always in operation when the fuel burning device it is serving is in operation; and G) Destruction or removal efficiency of the air pollution control equipment, including the following information: 1) Destruction or removal efficiency, in percent; 2) Current primary and secondary equipment control information codes from EPA AIRS Air Facility Subsystem List for each piece of control equipment; 3) Date tested; and 4) Method of determining destruction or removal efficiency, if not tested.	Maintain at the facility at all times	MK1 & MK2	Env-A 905.03 (formerly Env-A 901.08(c)(6))
11.	<u>Boiler Operating Hour Records:</u> The owner or operator shall maintain a log to record the number of hours of operation of MK1 and MK2 each month. This log may be part of the existing work management system.	Monthly	MK1 & MK2	Env-A 906 & Temporary Permits FP-T-0054 & TP-B-0462
12.	<u>Emergency Generator Operating Records:</u> The owner or operator shall record and maintain monthly and consecutive 12-month records of the operating hours of the emergency generator.	Monthly and consecutive 12-month periods	MKEG	Env-A 906 & State Permit to Operate PO-B-1788

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
13.	Coal Crusher Records: The Permittee shall maintain the following information, which may be included in the facility work management system: A) The monthly visible emission observation results for the secondary crusher; B) A log of repairs made to the coal crusher enclosure. The log shall include the following: 1) The date a problem was observed; 2) The date of the repair; 3) A description of the problem; and 4) The corrective actions taken.	Monthly for visible emission observation records and for each occurrence for repairs	MKPCC & MKSCC	State Permits to Operate No. PO-BP-2416 & PO-BP-2417
14.	Certificate of Representation: The Permittee shall complete and retain a certificate of representation for a designated representative or an alternate designated representative including the elements pursuant to 40 CFR 72.24, *Certificate of representation*.	Maintain at the facility at all times	MK1 & MK2	40 CFR §72.24
15.	Regulated Toxic Air Pollutant Records: The Permittee shall maintain records in accordance with the applicable method used to demonstrate compliance pursuant to Env-A 1405.	Maintain at facility at all times	All devices subject to RSA 125-I and Env-A 1400	Env-A 902.01 (c) State-Only Enforceable

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
16.	Monitoring Records: The Permittee shall maintain records of monitoring results as specified in Table 7 of this Permit including the following: A) Visible emission/opacity test results for the MKSCC, MKCT1, and MKCT2; B) NOx , SO_2 , CO_2, and continuous emissions monitoring data for MK1 & MK2; C) Continuous opacity monitoring data for MK1 & MK2; D) Stack volumetric flow rate (in kscfm) for MK1 & MK2; E) Outlet temperature of each ESP; F) Daily and monthly ammonia consumption of each SCR; G) Coal throughput for the MKPCC & MKSCC (primary and secondary coal crushers); H) Net electrical output; I) Coal E Belt scale calibrations/verifications for MK1 and MK2; J) Quantities of regulated substances facility-wide; K) Monthly and consecutive 12-month NOx, SO2, CO, PM10, and VOC emissions from MKEB; and L) Daily NOx emissions for MKCT1 and MKCT2 in lb/MMBtu and lb/hr, and monthly NOx emissions in tons/month and the tons/consecutive 12-month period using the stack test results and operating hours.	Maintain at facility at all times	As specified for each monitoring record	40 CFR 70.6(a)(3)(ii)
17.	Operating Scenario Records: PSNH shall maintain a record of the scenarios under which it is operating. PSNH shall specify whether operation is under normal conditions or an alternative operating scenario listed in Section VII. PSNH shall specify which alternative operating scenario is in use.	Whenever operation method changes from normal operation to a specific alternative operating scenario	Facility wide	40 CFR 70.6 (a)(9)
18.	Multi-pollutant Budget and Trading Program Recordkeeping Requirements: The permittee shall comply with the recordkeeping requirements of the multi-pollutant budget and trading program.	As required by the rule	MK1 & MK2	Env-A 2900 State-Only Enforceable
19.	On an hourly and daily basis, the owner or operator shall record fuel consumption for each fuel type, in gallons per hour and totalized gallons per day..	Hourly and daily	MKEB	40 CFR 60 Subpart Dc §60.48c(g)

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
20.	The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the Emergency Boiler.	For each occurrence	MKEB	40 CFR 60 Subpart A §60.7(b)
21.	The owner or operator shall maintain a file of all fuel flow (gal/hr) and totalizer measurements (gal/day) for the Emergency Boiler; all fuel flow meter and totalizer calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection.	Maintain at facility at all times	MKEB	40 CFR 60 Subpart A §60.7(f)
22.	Representative Actual Annual Emissions Test Recordkeeping Requirements: PSNH shall maintain records of SO2, NOx, CO, PM, and VOC emissions in tons/month and tons per consecutive 12-month period for MK1 and MK2.	Monthly and consecutive 12-month period	MK2	40 CFR 52.21(b)(21) and (33), dated July 1, 2002 and 40 CFR 70.6(a)(3)(ii) and Env-A 906
23.	ESP Monitoring Records: The owner or operator shall maintain the following records for each ESP: A) Fields out of service for each ESP unit, B) The time the field stopped operating, C) The reason for the field being out of service, D) The time the field was returned to service, and E) Corrective actions taken to return the field to service.	Daily	MK1-PC1, MK1-PC2, MK2-PC4 & MK2-PC5	40 CFR 70.6(a)(3)(ii)

Table 8 – Applicable Recordkeeping Requirements[33]				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
24.	<u>VOC Recordkeeping Requirements</u> The owner or operator shall record and maintain the following information at the facility: A) Facility information, including the following: 1) Source name; 2) Source identification; 3) Physical address; 4) Mailing address; B) Identification of each VOC emitting device or process except the following: 1) Processes or devices associated with non-core activities and 2) Processes processes or devices emitting exempt VOCs. C) Operating schedule information for each VOC emitting device/process identified in B) above, including the following: 1) Days of operation per calendar week during the normal operating schedule; 2) Hours of operation per day during normal operating schedule and for a typical high ozone day, if different from the normal operating schedule; and 3) Hours of operation per year under normal operating conditions; D) The following VOC emissions data for each VOC-emitting process/device identified in B) above: 1) Annual theoretical potential emissions, in tons per year and during a typical day during the high ozone season of each, in pounds per day; 2) Applicable emission factors, if used to calculate emissions and origin of the emission factors; and 3) Actual emissions from each VOC-emitting device or process identified in B) above, in tons per year and a typical day during the high ozone season in pounds per day.	Annually and as applicable	MK1, MK2, MKCT1, MKCT2, MKEB, MKEG	Env-A 904.02 (formerly 901.06

K. Reporting Requirements

The Permittee is subject to the federally enforceable reporting requirements identified in Table 9 below:

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
1.	<u>CEMS Recertification Notifications and Reports:</u> A) The Permittee shall notify EPA and DES by telephone or in writing and not later than 21 days prior to the first scheduled day of full recertification testing and at least 7 calendar days prior to the first scheduled day of partial recertification testing (when all of the tests are not required). In emergency situations when equipment fails with lost data, the Permittee may provide notice within 2 business days following the date when testing is scheduled. If the testing is rescheduled, the Permittee may notify DES and EPA by telephone or other means within 2 business days prior to the scheduled test date or the revised test date, whichever is earlier. B) Within 45 calendar days after completing all recertification tests, the Permittee shall submit to EPA and DES the electronic and hardcopy information contained in 40 CFR 75.63. C) Pursuant to Env-A 3212.14 and Env-A 2910.10, the permittee shall submit an application to DES within 45 days after completing all initial certification or recertification tests including the information required under 40 CFR 75, Subpart H. D) Pursuant to Env-A 2910.07, the permittee shall also submit written notification required pursuant to 40 CFR 75.61 to the ATS administrator.	7 days prior to partial recertification, 21 days prior to full recertification, and 45 days after all recertification tests[35]	MK1 & MK2	40 CFR §75.61 (a)(1), 75.70, 75.63, and 75.73(d) and Env-A 3212 and 2910
2.	<u>Relative Accuracy Test Audit (RATA) Notification and Reports:</u> A) The Permittee shall submit written notice to DES no later than 21 calendar days prior to the first scheduled day of testing. If the testing is rescheduled, the Permittee may notify DES by telephone or other means no later than 24-hours in advance of the new	21 calendar days prior to RATA	MK1 & MK2	40 CFR §75.61 (a)(5), §75.73(d), Env-A 3212.11, Env-A 2910, Env-A 808.05, and

[35] For Items 1, 2, and 3, PSNH – Merrimack Station shall comply with the more stringent notification and reporting requirements specified in Env-A 800 instead of those specified in 40 CFR 75, with the exception of notification and/or reporting required by Env-A 2900 or Env-A 3200 which shall be done at the frequencies specified in 40 CFR 75. Env-A 808 requires at least 30 days notification to DES prior to the scheduled date of a CEM certification, Relative Accuracy Test Audit, or Performance Specification testing and requires that the final report for the CEM certification and the RATA be submitted 30 days following the end of the quarter and for the Performance Specification Testing be submitted 30 days after completion of the testing.

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	testing date. Pursuant to Env-A 808.07, PSNH shall notify DES at least 30 days prior to the performance of the RATA. DES shall require rescheduling of the RATA if staff necessary to observe the RATA are not available. B) If requested, the Permittee shall submit the quality assurance RATA reports to EPA and DES by the later of 45 days after completing a quality assurance RATA or 15 days of receiving the request. C) Pursuant to Env-A 2910.07, the permittee shall also submit written notification required pursuant to 40 CFR 75.61 to the ATS administrator.			Env-A 808.07(c) and (d)
3.	CEMS Performance Specification Testing Reports: A) DES shall be notified of the date or dates of the performance specification testing at least 30 days prior to the scheduled dates. B) The owner or operator shall submit to DES a written report summarizing the testing within 30 days of the completion of the test.	30-day notice to DES prior to test; test report to DES 30 days after the test	MK1 & MK2	Env-A 808.05
4.	CEMS General Audit Notification Requirements: The owner or operator shall notify DES at least 2 weeks prior to any planned audit or test procedure except for RATAs, where the owner or operator shall provide at least 30 days notice prior to the performance of the RATA.	2 weeks prior to any planned audit or test procedure and at least 30 days prior to the RATA.	MK1 & MK2	Env-A 808.07(c) and (e)

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
5.	<u>Monitoring and QA/QC Plan Submittals:</u> A) Electronic copy: The Owner or Operator shall submit a complete, electronic, up-to-date monitoring plan to EPA and DES as follows: 1) No later than 21 days prior to the initial certification tests; 2) At the time of recertification application submission; 3) In each electronic quarterly report (Item #6 of Table 11); and 4) Whenever an update of the electronic monitoring plan information is required under 40 CFR 75.53(b). B) Hardcopy: The Owner or Operator shall submit all of the hardcopy information required by 40 CFR 75.53 to EPA and DES prior to initial certification. Thereafter, the Owner or Operator shall submit hardcopy information only if that portion of the monitoring plan is revised. The Owner or Operator shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the certification or recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to 40 CFR 75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request. C) Contents: The monitoring plan shall contain the information specified in 40 CFR 75.53. D) Format: The designated representative shall submit each monitoring plan in a format specified by EPA.	As specified	MK1, MK2, MKCT1, & MKCT2	40 CFR §75.62, §75.73(d) and (e), Env-A 808.04, Env-A 808.06, Env-A 3212, and Env-A 2910
6.	<u>Quarterly Reports:</u> A) The Permittee shall submit to DES and EPA in electronic format or other format as approved by DES and/or EPA 30 calendar days after the end of the calendar quarter the information contained in 40 CFR 75.64(a), 40 CFR 75.73(f), 40 CFR 75.74, Env-A 2912, Env-A 3212, Env-A 3214, Env-A 808.11(new), and Env-A 808.13 (new) and the following information: 1) Opacity, SO_2, NOx, and CO_2 emissions as calculated by the CEMS. 2) The 24-hour averages of the following shall be reported, whether or not an excess emission has occurred:	30 calendar days after the end of the calendar quarter	MK1, MK2,	40 CFR §75.64, §75.73(f), §75.57(f), §75.74, 40 CFR 70.6(a)(3)(iii), Env-A 2910, Env-A 2911, Env-A 3212, Env-A 3214, Env-A 808.11(new), Env-A 808.13 (new) & Temporary

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	a. SO_2 lb/mmBtu, SO_2 ppm, and SO_2 lb/hr; b. NOx lb/mmBtu, NOx ppm, and NOx lb/hr; c. Percent CO_2 and CO_2 lb/hr as measured by continuous monitor/recorder; d. Stack volumetric flow rate (in kscfm); e. Load (in MW); f. Steam flow (in klbs/hr); g. Heat input (mmBtu/hr); h. Opacity (in percent); i. Fuel flow (in tons/day); j. Hours of operation (in hours/day); and k. Ammonia usage (in gallons/day). 3) Excess emission data recorded by the CEM system, including the following: a. The date and time of the beginning and ending of each of excess emissions; b. The magnitude of each excess emission; c. The specific cause of the excess emission; and d. The corrective action taken. 4) If no excess emissions have occurred, a statement to that effect; 5) For gaseous emission monitoring systems, the daily averages of the measurements made and emissions rates calculated. 6) A statement as to whether the CEM system was inoperative, repaired, or adjusted during the reporting period; 7) If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: a. The date and time of the beginning and ending of each period when the CEM was inoperative; b. The reason why the CEM was not operating; c. The corrective action taken; and d. The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or pollutant analyzer in the CEM system; 8) The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating; 9) When calibration gas is used, the following information: a. The calibration gas concentration; b. If a gas bottle was changed during the			Permits TP-B-0462 & TP-B--0054

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	quarter: i) The date of the calibration gas bottle change; ii) The gas bottle concentration before the change; and iii) The gas bottle concentration after the change; and c. The expiration date for all calibration gas bottles used. 10) Excess emissions of SO_2 shall be defined as an annual SO_2 emission, which exceeds the state acid rain emission limitation, as calculated from CEM data. B) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports represent current operating conditions. C) The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. D) The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of 40 CFR 75, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. E) For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of 40 CFR 75.34(a)(1), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NOx emissions, pursuant to 40 CFR 75.34. F) For a unit that is reporting on a control period basis, the designated representative shall also include a certification that the NOx emission rate and NOx concentration values substituted for missing data under 40 CFR 75 Subpart D are calculated using only values from a control period and do not systematically underestimate NOx emissions.			

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	G) Pursuant to Env-A 3212.15(e) and Env-A 2910.11(a)(3), the quarterly reports shall be submitted in the manner specified in 40 CFR 75, Subpart H and 40 CFR 75.64. H) Pursuant to Env-A 3212.15(f) and Env-A 2910.11(a)(4), for MK1 & MK2, the quarterly reports shall include all of the data and information required in 40 CFR Subpart H and 40 CFR Subpart G. I) Pursuant to Env-A 3214.01 and Env-A 2911.01, the owner or operator shall also submit emissions and operations information in electronic format as part of the quarterly reports. J) Pursuant to Env-A 3214.02, the owner or operator shall also submit to the NETS administrator in the quarterly reports, NOx emissions in lb/hr for every hour during the control period and cumulative quarterly and seasonal NOx emission data in pounds. K) Pursuant to Env-A 2911.02, the owner or operator shall also submit to the ETS administrator in the quarterly reports, SO_2, NOx and CO_2 emissions in lb/hr for every hour during the year and cumulative quarterly and annual SO_2, NOx and CO_2 emissions data in pounds.			
7.	<u>Excess Emissions Requirements</u> If either of these devices has excess emissions of NOx or SO2 in any calendar year, then the owner or operator shall submit a proposed offset plan, as required under 40 CFR 77. The owner or operator of an affected source that has excess emissions in any calendar year shall: A) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR 77.6; and B) Comply with the terms of an approved offset plan, as required by 40 CFR 77.3.	Within 60 days after the end of any calendar year where a unit has excess emissions of sulfur dioxide or nitrogen oxide	MK1 & MK2	40 CFR §72.9(e)
8.	<u>Offset Plans for Excess SO_2 Emissions</u>: The Permittee shall submit an offset plan no later than 60 days after the end of any calendar year during which a unit has excess SO_2 emissions. The offset plan shall contain the information pursuant to 40 CFR 77.3.	Within 60 days after the end of any calendar year where a unit has excess emissions of sulfur dioxide	MK1 & MK2	40 CFR §77.3

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
9.	Quarterly Audit Reports: Pursuant to Env-A 808.07 (new), the Permittee shall submit to DES, a written summary report of the results of all required audits that were performed in that quarter, in accordance with the following: A) For gaseous CEM audits, the report format shall conform to that presented in 40 CFR 60, Appendix F, Procedure 1, Section 7; and B) For opacity CEM audits, the report format shall conform to that presented in EPA-600/8-87-025, April 1992, "Technical Assistance Document: Performance Audit Procedures for Opacity Monitors."	Quarterly, no later than 30 calendar days after the end of the quarter for which reporting is required	MK1 & MK2	Env-A 808.07 (new)
10.	Net Thermal and Electrical Output Reporting: The facility shall report the net thermal and electrical output of each affected source for each month of the calendar year to DES.	Annually (no later than April 15^{th} of the following year)	MK1, MK2, MKCT1, & MKCT2	Env-A 2906.05(g) & Env-A 3207.04(h)
11.	Coal Quarterly Reports: Quarterly reports shall be submitted to DES, which include the following information for each coal shipment. The data shall be summarized on a monthly basis. Submittal of the "Monthly Report of Cost and Quality of Fuel for Electric Plants", will satisfy the requirements of this condition. A) The shipment date; B) The weight of coal received in tons; C) Identification of the mine from which the coal came from; D) The ash content in weight percent of the coal; E) The sulfur lb/mmBtu content of coal or the weight percent of sulfur in the coal; and F) The gross heat content of the coal in Btu/lb.	Within 30 days after each calendar quarter	MK1 & MK2	Env-A 910 & Temporary Permits FP-T-0054 & TP-B-0462

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
12.	Performance Test Reports: The Permittee shall submit a report to DES documenting the results of the compliance stack emission test. The compliance stack emission test report shall contain the following information: A) All the information required for the pre-test protocol as described in Env-A 802.04; B) All test data; C) All calibration data; D) Process data agreed by DES and the Permittee to be collected; E) All test results; F) A description of any discrepancies or problems that occurred during testing or sample analysis; G) An explanation of how discrepancies or problems were treated and their effect on the final results; and H) A list and description of all equations used in the test report, including sample calculations for each equation used.	No later than 60 days after a performance test	Facility wide	Env-A 802.11 (new)
13.	Quarterly Fuel Usage Report: Monthly fuel usage information by device, fuel type, and sulfur content shall be submitted in writing to the DES.	Within 30 days after the end of a calendar quarter	MK1, MK2, MKCT1, MKCT2	Env-A 910 & Temporary Permits FP-T-0054 & TP-B-0462 and Env-A 907.02 State-Only Enforceable
14.	NOx Reporting Requirements: The Permittee shall submit reports of the NOx records kept pursuant to the Section VIII. I. Table 10.	Annually (no later than April 15th of the following year)	MK1, MK2, MKCT1, MKCT2, MKEG, & MKEB	Env-A 909.03 (formerly Env-A 901.09)
15.	Ammonia Consumption of SCR Systems: Submit monthly ammonia consumption for each SCR System (MK1-PC3 and MK2-PC6) during the calendar year.	Annually (no later than April 15th of the following year)	MK1-PC3 & MK2-PC6	40 CFR 70.6(a)(3)(iii) & Temporary Permits FP-T-0054 & TP-B-0462
16.	Regulated Toxic Air Pollutant Reports: The Permittee shall report actual emissions speciated by individual regulated toxic air pollutants, including a breakdown of VOC emission compounds.	Annually (no later than April 15th of the following year)	All devices subject to RSA 125-I and Env-1400	Env-A 907.01 (new) State-Only Enforceable

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
17.	<u>Semi-Annual Permit Deviation/Monitoring Reports:</u> The Permittee shall submit a permit deviation/monitoring report of the data specified in Table 9 of this Permit every 6 months. All required reports must be certified by a responsible official consistent with 40 CFR 70.5(d). The report shall contain a summary of the following information, unless this information was provided to DES pursuant to another requirement: A) Visible emission/opacity test results; B) Summary showing monthly average sulfur content of the liquid and solid fuels from testing and/or delivery ticket and/or other documentation certifications for liquid and solid fuel sulfur content; C) Fuel consumption for all combustion devices except for MK1 & MK2; D) Coal throughput for the coal crushers; E) Any fields out of service in any of the ESP's during the reporting period, including the time the field stopped operating, the reason for the field being out of service, the time the field was returned to service, and any corrective action taken; and F) All instances of deviations from Permit requirements.	Semiannually (by July 31st and January 31st of each calendar year)	Facility wide	40 CFR 70.6(a)(3)(iii)(A)
18.	<u>ESP Reports:</u> A) Within 24 hours of discovery of more than 7 fields out of service on MK1-PC1 and MK1-PC2 combined, the owner or operator shall notify (e.g., via call or email, etc.) DES on the next business day of the number of fields out of service in any of the ESPs. B) Within 24 hours of discovery of more than 8 fields out of service on MK2-PC4 and MK2-PC5 combined, the owner or operator shall notify (e.g., via call or email, etc.) DES on the next business day of the number of fields out of service in any of the ESPs.	Each occurrence	MK1-PC1, MK1-PC2, MK2-PC4 & MK2-PC5	40 CFR 70.6 (a)(3)(iii)(B)
19.	<u>Prompt Reporting of Permit Deviations:</u> The Permittee shall promptly report deviations from permit requirements by phone, fax or e-mail in accordance with Section XXVIII of this permit and Env-A 911 (new).	Within 24 hours of discovery of occurrence	Facility wide	Env-A 911 & 40 CFR 70.6 (a)(3)(iii)(B)
20.	<u>Certification by the Designated Representative or the Alternate Designated Representative:</u> Any document submitted under the Acid Rain program shall be signed and certified by the designated representative or the alternate designated representative and include the statements pursuant to 40 CFR 72.21 (a)(1) and (2).	With each submittal	MK1 & MK2	40 CFR §72.21

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
21.	Certification by a Responsible Official: Any application form, report, or compliance certification submitted to the DES and/or EPA shall contain certification by a responsible official of truth, accuracy, and completeness as outlined in Section XXI.B of this permit.	With each submittal	Facility wide	40 CFR 70.5 (d)
22.	Emissions Reporting and Emissions Fees: The Permittee shall submit reports of actual emissions of all significant and insignificant activities and payment of emissions-based fees in accordance with Env-A 700 and Section XXIII of this permit.	Quarterly payment on the 15th day of the 2nd quarter after actual emissions occurred; Reporting of actual annual emissions done annually by April 15th the following year	Facility wide	Env-A 907.01 (new) & Env-A 705.03 & 705.04
23.	NOx Budget Program Annual Compliance Certification: For each control period (May 1 to September 30 of each year), the AAR for each budget source shall submit an annual compliance certification to DES containing the information specified in Env-A 3216.03.	November 30th each calendar year	MK1, MK2, MKCT1, MKCT2	Env-A 3216 State-Only Enforceable
24.	Multi-pollutant Budget and Trading Program Annual Compliance Certification: The Permittee shall submit an annual compliance certification to DES for the prior year containing all of the information listed in Env-A 2913.03(a) through (e).	By January 30th of each year, beginning in 2007	MK1 & MK2	Env-A 2913.01, 2913.02, & 2913.03 State-Only Enforceable
25.	Annual Title V Compliance Certification: The Permittee shall submit an annual compliance certification in accordance with Section XXI of this permit.	Annually (no later than April 15th of the following year)	Facility wide	40 CFR 70.6(c)(1)

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
26.	NSPS Subpart Dc Initial Notification Requirements for the Emergency Boiler: Each time the owner or operator brings in an Emergency Boiler to the PSNH Merrimack Station, the owner or operator shall furnish the EPA and DES written notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by 40 CFR 60, Subpart A, Section 60.7. This notification shall include: A) The design heat input capacity of the boiler and identification of fuels to be combusted in the boiler; B) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for the boiler (e.g., a copy of this permit); and C) The annual capacity factor at which the facility anticipates operating the boiler based on all fuels combined and each individual fuel. Notification of the date of construction/installation of the boiler is commenced is due no later than 30 days after such date. Notification of the anticipated initial startup of the boiler, must be postmarked not more than 60 days nor less than 30 days prior to the initial startup date. Notification of the actual date of initial startup of the boiler is commenced must be postmarked within 15 days after the initial startup date.	As stated for each installation of an Emergency Boiler	MKEB	40 CFR 60 Subpart Dc §60.48c(a)
27.	NSPS Subpart Dc Performance Test Report for the Emergency Boiler: Each time the owner or operator brings in an Emergency Boiler for operation, the owner or operator shall submit to EPA and DES results of the performance test for opacity and the fuel supplier certification for the first load of No. 2 fuel oil or on-road low sulfur diesel oil for consumption in the Emergency Boiler.	Within 60 days of completion of testing	MKEB	40 CFR 60 Subpart Dc §60.48c(b)

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
28.	NSPS Subpart Dc Semi-annual Fuel Report for the Emergency Boiler: The owner or operator shall submit semi-annual reports to EPA and DES, postmarked within 30 days following the end of the reporting period, including: A) Calendar dates covered in the reporting period; B) Each 30-day average sulfur content (weight percent) for each fuel type (No. 2 fuel oil and on-road low sulfur diesel oil) for each 30-day period during the reporting period; reasons for any non-compliance with the emission standards; and description of corrective actions taken. C) If fuel supplier certification is used to demonstrate compliance, the fuel supplier certification must include the name of the fuel supplier, a statement that the fuel oil complies with specifications under the definition of distillate oil for fuel oil no. 2 in 40 CFR 60.41c , and the sulfur content or maximum sulfur content of the no. 2 fuel oil and the on-road low sulfur diesel fuel oil. D) A certified statement by the responsible official that the fuel supplier certification represents all of the fuel combusted during the period.	Semi-annually, (by July 31st and January 31st of each calendar year) within 30 days following the end of the reporting period to DES and EPA	MKEB	40 CFR 60 Subpart Dc §60.48c(d), (e), & (j)
29.	RSA 125-O Mercury Emissions Reporting Requirement The owner shall report by June 30, 2007, and annually thereafter, to the legislative oversight committee on electric utility restructuring, established under RSA 374-F:5, and the chairpersons of the House science, technology, and energy committee, and the Senate energy and economic development committee, on the progress and status of complying with the requirements of RSA 125-O:13,I. and III., relative to achieving early reductions in mercury emissions and also installing and operating the scrubber technology, including any updated cost information. The last report required shall be after the Department has made a determination, under RSA 125-O:13,V., on the maximum sustainable rate of mercury emissions reductions by the scrubber technology.	Annually, by June 30	MK1 & MK2	RSA 125-O:13,IX. (State-Only Enforceable)
30.	CO_2 Budget Trading Program Reports The CO_2 AAR shall submit quarterly reports as follows: A) The CO_2 AAR shall report the CO_2 mass emissions data for the CO_2 budget unit, in an electronic format prescribed by the Administrator unless otherwise prescribed by the regional organization, for each calendar quarter beginning with the calendar quarter covering January 1, 2009 through March 31, 2009; B) The CO_2 AAR shall submit each quarterly report to	Quarterly (no later than 30 days following the end of each quarterly reporting period)	MK1 & MK2	Env-A 4609.16(c)

Table 9 – Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	the regional organization within 30 days following the end of the calendar quarter covered by the report, in the manner specified in Subpart H of 40 CFR 75 and 40 CFR 75.64; C) Quarterly reports shall be submitted for each CO_2 budget unit which include all of the data and information required in Subpart G of 40 CFR 75, except for opacity, NOx, and SO_2 provisions; and D) The CO_2 AAR shall include a compliance certification with, and in support of, each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that: 1) The monitoring data submitted were recorded in accordance with the applicable requirements of both 40 CFR 75 and Env-A 4600, including the quality assurance procedures and specifications; and 2) The CO_2 concentration values substituted for missing data under Subpart D of 40 CFR 75 do not systematically underestimate CO_2 emissions.			
31.	<u>Certification by the CO_2 Authorized Account Representative</u> Any submission under the CO_2 budget trading program shall be signed and certified by the CO_2 Authorized Account Representative and shall include the certification statement pursuant to Env-A 4604.01(e).	With each submittal	MK1 & MK2	Env-A 4604.01(e)
32.	<u>CO_2 Budget Program Annual Compliance Certification</u> A) For each control period in which a CO_2 budget source is subject to the requirements of Env-A 4605, the CO_2 AAR of the source shall submit to the Department by March 1 following the relevant control period, a compliance certification report. B) The CO_2 AAR shall include in the compliance certification report under (a), above, the following elements, in a format prescribed by the Department: 1) Identification of the source and each CO_2 budget unit at the source; 2) At the CO_2 AAR's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account under Env-A 4605.06 for the control period, including the serial numbers of any CO_2 offset allowances that are to be deducted subject to the limitations of Env-A 4605.04; and 3) The compliance certification specified in (c),	By March 1 (following the relevant control period), beginning March 1, 2012 and every 3 years thereafter	MK1 & MK2	Env-A 4605.09

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	below. C) In the compliance certification report required by A), above, the CO_2 AAR shall certify, based on reasonable inquiry of those individuals with primary responsibility for operating the source and the CO_2 budget units at the source in compliance with the CO_2 Budget Trading Program, whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the calendar years covered by the report in compliance with the requirements of the CO_2 Budget Trading Program, including: 1) Whether the source was operated in compliance with the requirements of Env-A 4605; 2) Whether the monitoring plan applicable to each unit at the source has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute CO_2 emissions to the unit, in accordance with Env-A 4609; 3) Whether all CO_2 emissions from the units at the source were monitored or accounted for through the missing data procedures specified in 40 CFR 75 Subpart D, or 40 CFR 75 appendix D or appendix E and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Env-A 4609. If conditional data were reported, the Owner or Operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made; 4) Whether the facts that form the basis for certification under Env-A 4609 of each monitor at each unit at the source, or for using an excepted monitoring method or alternative monitoring method approved under Env-A 4609, if any, have changed; and 5) If a change is required to be reported under (c)(iv), above, the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.			
33.	*Representative Actual Annual Emissions Reporting*	Annually (no	MK2	40 CFR

Table 9 – Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	<u>Requirements:</u> PSNH shall submit to DES annually, SO2, NOx, CO, PM, and VOC emissions in tons/month and consecutive 12-month period for MK1 and MK2.	later than April 15^{th} the following year)		52.21(b)(21) and (33), dated July 1, 2002 and Env-A 910 (new)
34.	<u>Notification Requirements</u> A) Pursuant to Env-A 3212.09, the permittee shall comply with the notification requirements of Env-A 3212.07 and 40 CFR 75.20(f) for MKCT1 & MKCT2 B) Pursuant to Env-A 3212.11, for MKCT1 & MKCT2, the permittee shall submit written notification to DES only.	As specified	MKCT1& MKCT2	Env-A 3212
35.	<u>Quarterly Reports for MKCT1 and MKCT2</u> The Permittee shall submit to DES and EPA in electronic format or other format as approved by DES and/or EPA the information as follows: A) Pursuant to Env-A 3212.15(b), the owner or operator shall either meet all of the requirements related to 40 CFR 75 related to monitoring and reporting NOx mass emissions during the entire year or submit quarterly only for the periods from the earlier of May 1 or the date and hour that the owner or operator successfully completes all of the recertification tests required in accordance with 40 CFR 75.74 through September 30^{th} of each year in accordance with 40 CFR 75.74(b); B) Pursuant to Env-A 3212.15(e), the quarterly reports shall be submitted in the manner specified in 40 CFR 75, Subpart H and 40 CFR 75.64; C) Pursuant to Env-A 3212.15(g), the quarterly reports shall include all of the data and information required in 40 CFR 75 Subpart H; and D) Pursuant to Env-A 3214.02, the owner or operator shall also submit to the NETS administrator NOx emissions in lb/hr for every hour during the control period and cumulative quarterly and seasonal NOx emission data in pounds.	30 calendar days after the end of the 2^{nd} and 3^{rd} calendar quarter	MKCT1 & MKCT2	Env-A 3212, Env-A 3214, 40 CFR 75, Subpart G & H
36.	<u>VOC Reporting Requirements</u> The owner or operator shall submit each the following information: A) Facility information, including the following: 4) Source name; 5) Source industrial classification (SIC) code; 6) Physical address; and 7) Mailing address; B) Identification of each VOC emitting device or process;	Annually (no later than April 15^{th} of the following year	MK1, MK2, MKCT1, MKCT2, MKEG, & MKEB	Env-A 908 (formerly Env-A 901.07)

Table 9 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	C) Operating schedule information for each VOC emitting device, including the following: 1) A typical business day; 2) A typical high ozone season day, if different from a typical business day. D) Total quantities of actual VOC emissions fro the entire facility and for each device or process including the following: 1) Annual VOC emissions, in tons; and 2) Typical high ozone season day VOC emissions, in pounds per day.			

IX. Requirements Currently Not Applicable

The Permittee did not identify any requirements that are not applicable to the facility.

General Title V Operating Permit Conditions

X. Issuance of a Title V Operating Permit

A. This Permit is issued in accordance with the provisions of Part Env-A 609. In accordance with 40 CFR 70.6(a)(2), this Permit shall expire on the date specified on the cover page of this Permit, which shall not be later than the date five (5) years after issuance of this Permit.

B. Permit expiration terminates the Permittee's right to operate the Permittee's emission units, control equipment or associated equipment covered by this permit, unless a timely and complete renewal application is **received by the Department** at least 6 months before the expiration date.

XI. Title V Operating Permit Renewal Procedures

Pursuant to Env-A 609.07(b), an application for renewal of this Permit shall be considered timely if it is **received by the Department** at least six months prior to the designated expiration date of the current Title V operating permit.

XII. Application Shield

Pursuant to Env-A 609.08, if an applicant submits a timely and complete application for the issuance or renewal of a Permit, the failure to have a Permit shall not be considered a violation of this part until the Director takes final action on the application.

XIII. Permit Shield

A. Pursuant to Env-A 609.09(a), a permit shield shall provide that:

1. For any applicable requirement or any state requirement found in the New Hampshire Rules Governing the Control of Air Pollution specifically included in this Permit, compliance with the conditions of this Permit shall be deemed compliance with said applicable requirement or said state requirement as of the date of permit issuance; and

2. For any potential applicable requirement or any potential state requirement found in the New Hampshire Rules Governing the Control of Air Pollution specifically identified in this Title V Operating Permit Section IX as not applicable to the stationary source or area source, the Permittee need not comply with the specifically identified federal or state requirements.

B. The permit shield identified in Section XIII.A. of this Permit shall apply only to those conditions incorporated into this Permit in accordance with the provisions of Env-A 609.09(b). It shall not apply to certain conditions as specified in Env-A 609.09(c) that may be incorporated into this Permit following permit issuance by DES.

C. If a Title V Operating Permit and amendments thereto issued by the DES does not expressly include or exclude an applicable requirement or a state requirement found in the NH Rules Governing the Control of Air Pollution, that applicable requirement or state requirement shall not be covered by the permit shield and the Permittee shall comply with the provisions of said requirement to the extent that it applies to the Permittee.

D. If the DES determines that this Title V Operating Permit was issued based upon inaccurate or incomplete information provided by the applicant or Permittee, any permit shield provisions in said Title V Operating Permit shall be void as to the portions of said Title V Operating Permit which are affected, directly or indirectly, by the inaccurate or incomplete information.

E. Pursuant to Env-A 609.09(f), nothing contained in Section XIII of this Permit shall alter or affect the ability of the DES to reopen this Permit for cause in accordance with Env-A 609.19 or to exercise its summary abatement authority.

F. Pursuant to Env-A 609.09(g), nothing contained in this section or in any title V operating permit issued by the DES shall alter or affect the following:

1. The ability of the DES to order abatement requiring immediate compliance with applicable requirements upon finding that there is an imminent and substantial endangerment to public health, welfare, or the environment;

2. The state of New Hampshire's ability to bring an enforcement action pursuant to RSA 125-C:15,II;

3. The provisions of section 303 of the CAA regarding emergency orders including the authority of the EPA Administrator under that section;

4. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

5. The applicable requirements of the acid rain program, consistent with section 408(a) of the CAA;

6. The ability of the DES or the EPA Administrator to obtain information about a stationary source, area source, or device from the owner or operator pursuant to section 114 of the CAA; or

7. The ability of the DES or the EPA Administrator to enter, inspect, and/or monitor a stationary source, area source, or device.

XIV. Reopening for Cause

The Director shall reopen and revise a Title V Operating Permit for cause if any of the circumstances contained in Env-A 609.19(a) exist. In all proceedings to reopen and reissue a Title V Operating Permit, the Director shall follow the provisions specified in Env-A 609.19(b) through (g).

XV. Administrative Permit Amendments

A. Pursuant to Env-A 612.01, the Permittee may implement the changes addressed in the request for an administrative permit amendment as defined in Part Env-A 100 immediately upon submittal of the request.

B. Pursuant to Env-A 612.01, the Director shall take final action on a request for an administrative permit amendment in accordance with the provisions of Env-A 612.01(b) and (c).

XVI. Operational Flexibility

A. Pursuant to Env-A 612.02, the Permittee subject to and operating under this Title V Operating Permit may make changes involving trading of emissions, off-permit changes, and section 502(b)(10) changes at the permitted stationary source or area source without filing a Title V Operating Permit application for and obtaining an amended Title V Operating Permit, provided that all of the following conditions are met, as well as conditions specified in Section XVI. B through E of this permit, as applicable. DES has included permit terms authorizing the generation of DERs.

1. The change is not a modification under any provision of Title I of the CAA;

2. The change does not cause emissions to exceed the emissions allowable under the Title V operating permit, whether expressed therein as a rate of emissions or in terms of total

emissions;

3. The owner or operator has obtained any temporary permit required by Env-A 600;

4. The owner or operator has provided written notification to the director and administrator of the proposed change and such written notification includes:

   a) The date on which each proposed change will occur or has occurred;

   b) A description of each such change;

   c) Any change in emissions that will result;

   d) A request that the operational flexibility procedures be used; and

   e) The signature of the responsible official, consistent with Env-A 605.04(b);

5. The change does not exceed any emissions limitations established under any of the following:

   a) The New Hampshire Code of Administrative Rules, Env-A 100-4300;

   b) The CAA; or

   c) This Title V Operating Permit; and

6. The Permittee, DES, and EPA have attached each written notice required above to their copy of this Title V Operating Permit.

B. For changes involving the trading of emissions, the Permittee must also meet the following conditions:

1. The Title V Operating Permit issued to the stationary source or area source already contains terms and conditions including all terms and conditions which determine compliance required under 40 CFR 70.6(a) and (c) and which allow for the trading of emissions increases and decreases at the permitted stationary source or area source solely for the purpose of complying with a federally-enforceable emissions cap that is established in the permit independent of otherwise applicable requirements;

2. The owner or operator has included in the application for the Title V Operating Permit proposed replicable procedures and proposed permit terms which ensure that the emissions trades are quantifiable and federally enforceable for changes to the Title V Operating Permit which qualify under a federally- enforceable emissions cap that is established in the Title V

Operating Permit independent of the otherwise applicable requirements;

3. The Director has not included in the emissions trading provision any devices for which emissions are not quantifiable or for which there are no replicable procedures to enforce emissions trades; and

4. The written notification required above is made at least 7 days prior to the proposed change and includes a statement as to how any change in emissions will comply with the terms and conditions of the Title V Operating Permit.

C. For off-permit changes, the Permittee must also meet the following conditions:

1. Each off-permit change meets all applicable requirements and does not violate any existing permit term or condition;

2. The written notification required above is made contemporaneously with each off-permit change, except for changes that qualify as insignificant under the provisions of Env-A 609.04;

3. The change is not subject to any requirements under Title IV of the CAA and the change is not a Title I modification;

4. The Permittee keeps a record describing the changes made at the source which result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under this Permit, and the emissions resulting from those changes; and

5. The written notification required above includes a list of the pollutants emitted and any applicable requirement that would apply as a result of the change.

D. For section 502(b)(10) changes, the Permittee must also meet the following conditions:

1. The written notification required above is made at least 7 days prior to the proposed change; and

2. The written notification required above includes any permit term or condition that is no longer applicable as a result of the change.

E. Pursuant to Env-A 612.02(f), the off-permit change and section 502(b)(10) change shall not qualify for the permit shield under Env-A 609.09.

XVII. Minor Permit Amendments

A. Pursuant to Env-A 612.05 prior to implementing a minor permit modification, the Permittee shall submit a written request to the Director in accordance with the requirements of Env-A 612.05(b).

B. The Director shall take final action on the minor permit amendment request in accordance with the provisions of Env-A 612.05(c) through (g).

C. Pursuant to Env-A 612.05(h), the permit shield specified in Env-A 609.09 shall not apply to minor permit amendments under Section XVII. of this Permit.

D. Pursuant to Env-A 612.05(a), the Permittee shall be subject to the provisions of RSA 125-C:15 if the change is made prior to the filing with the Director a request for a minor permit amendment.

XVIII. Significant Permit Amendments

A. Pursuant to Env-A 612.06, a change at the facility shall qualify as a significant permit amendment if it meets the criteria specified in Env-A 612.06(a)(1) through (5).

B. Prior to implementing the significant permit amendment, the Permittee shall submit a written request to the Director which includes all the information as referenced in Env-A 612.06(b) and (c) and shall be issued an amended Title V Operating Permit from the DES. The Permittee shall be subject to the provisions of RSA 125-C:15 if a request for a significant permit amendment is not filed with the Director and/or the change is made prior to the issuance of an amended Title V Operating Permit.

C. The Director shall take final action on the significant permit amendment in accordance with the Procedures specified in Env-A 612.06(d), (e) and (f).

XIX. Title V Operating Permit Suspension, Revocation or Nullification

A. Pursuant to RSA 125-C:13, the Director may suspend or revoke any final permit issued hereunder if, following a hearing, the Director determines that:

1. The Permittee has committed a violation of any applicable statute or state requirement found in the New Hampshire Rules Governing the Control of Air Pollution, order or permit condition in force and applicable to it; or

2. The emissions from any device to which this Permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.

B. The Director shall nullify any Permit, if following a hearing in accordance with RSA 541-A:30, II, a finding is made that the Permit was issued in whole or in part based upon any information proven to be intentionally false or misleading.

XX. Inspection and Entry

EPA and DES personnel shall be granted access to the facility covered by this Permit, in accordance with RSA 125-C:6,VII, for the purposes of: inspecting the proposed or permitted site; investigating a complaint; and assuring compliance with any applicable requirement or state requirement found in the NH Rules Governing the Control of Air Pollution and/or conditions of any Permit issued pursuant to Chapter Env-A 600.

XXI. Certifications

A. Compliance Certification Report

In accordance with 40 CFR 70.6(c) the Responsible Official shall certify, for the previous calendar year, that the facility is in compliance with the requirements of this permit. The report shall be submitted annually, no later than April 15th of the following year. The report shall be submitted to the DES and to the U.S. Environmental Protection Agency - New England Region. The report shall be submitted in compliance with the submission requirements below.

In accordance with 40 CFR 70.6(c)(5), the report shall describe:

1. The terms and conditions of the Permit that are the basis of the certification;

2. The current compliance status of the source with respect to the terms and conditions of this Permit, and whether compliance was continuous or intermittent during the reporting period;

3. The methods used for determining compliance, including a description of the monitoring, record keeping, and reporting requirements and test methods; and

4. Any additional information required by the DES to determine the compliance status of the source.

B. Certification of Accuracy Statement

All documents submitted to the DES shall contain a certification of accuracy statement by the responsible official of truth, accuracy, and completeness. Such certification shall be in accordance with the requirements of 40 CFR 70.5(d) and contain the following language:

> "I am authorized to make this submission on behalf of the facility for which the submission is made. Based on information and belief formed after reasonable inquiry, I certify that the statements and information in the enclosed documents are to the best of my knowledge and belief true, accurate and complete. I am aware that there are significant penalties for

submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

All reports submitted to DES (except those submitted as emission based fees as outlined in Section XXIII of this Permit) shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
ATTN: Section Supervisor, Compliance Bureau

All reports submitted to EPA shall be submitted to the following address:

Office of Environmental Stewardship
Director Air Compliance Program
United States Environmental Protection Agency
1 Congress Street
Suite 1100 (SEA)
Boston, MA 02114-2023
ATTN: Air Compliance Clerk

XXII. Enforcement

Any noncompliance with a permit condition constitutes a violation of RSA 125-C:15, and, as to the conditions in this permit which are federally enforceable, a violation of the Clean Air Act, 42 U.S.C. Section 7401 et seq., and is grounds for enforcement action, for permit termination or revocation, or for denial of an operating permit renewal application by the DES and/or EPA. Noncompliance may also be grounds for assessment of administrative, civil or criminal penalties in accordance with RSA 125-C:15 and/or the Clean Air Act. This Permit does not relieve the Permittee from the obligation to comply with any other provisions of RSA 125-C, the New Hampshire Rules Governing the Control of Air Pollution, or the Clean Air Act, or to obtain any other necessary authorizations from other governmental agencies, or to comply with all other applicable Federal, State, or Local rules and regulations, not addressed in this Permit.

In accordance with 40 CFR 70.6 (a)(6)(ii) a Permittee shall not claim as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

XXIII. Emission-Based Fee Requirements

A. The Permittee shall pay an emission-based fee quarterly for this facility as calculated each calendar year pursuant to Env-A 705.03.

B. The Permittee shall determine the total actual annual emissions from the facility to be included in the emission-based multiplier specified in Env-A 705.03(a) for each calendar year in accordance with the methods specified in Env-A 616.

C. The Permittee shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT * CPIm * ISF$$

Where:

FEE =	The annual emission-based fee for each calendar year as specified in Env-A 705.
E =	The emission-based multiplier is based on the calculation of total annual emissions as specified in Env-A 705.02 and the provisions specified in Env-A 705.03(a).
DPT =	The dollar per ton fee the DES has specified in Env-A 705.03(b).
CPIm=	The Consumer Price Index Multiplier as calculated in Env-A 705.03(c).
ISF =	The Inventory Stabilization Factor as specified in Env-A 705.03(d).

D. The Permittee shall contact the DES each calendar year for the value of the Inventory Stabilization Factor.

E. The Permittee shall contact the DES each calendar year for the value of the Consumer Price Index Multiplier.

F. The Permittee shall submit, to the DES, payment of the emission-based fee and a summary of the calculations referenced in Sections XXIII.B. and C. of this Permit for each calendar year. The total emission-based fee shall be paid in four equal installments on a quarterly basis. The quarterly payments shall be made in accordance with Env-A 705.04 on the 15^{th} day of the following months:

1. July of the year to which the fee applies (e.g., January, February, March 2009 emission-based fees are due July 15, 2009);

2. October of the year to which the fee applies (e.g., April, May, June 2009 emission-based fees are due on October 15, 2009).

3. January of the following year (e.g., July, August, September 2009 emission-based fees are due on January 15, 2010);

4. April of the following year (e.g., October, November, December 2009 emission-based fees are due on April 15, 2010).

The Permittee shall pay any remaining balance of the total annual emission-based fee no later than April 15^{th} of the following year.

The emission-based fee and summary of the calculations shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
ATTN.: Emissions Inventory

G. The DES shall notify the Permittee of any under payments or over payments of the annual emission-based fee in accordance with Env-A 705.05.

XXIV. Duty To Provide Information

In accordance with 40 CFR 70.6 (a)(6)(v), upon the DES's written request, the Permittee shall furnish, within a reasonable time, any information necessary for determining whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall furnish to the DES copies of records that the Permittee is required to retain by this Permit. The Permittee may make a claim of confidentiality as to any information submitted pursuant to this condition in accordance with Part Env-A 103 at the time such information is submitted to DES. DES shall evaluate such requests in accordance with the provisions of Part Env-A 103.

XXV. Property Rights

Pursuant to 40 CFR 70.6 (a)(6)(iv), this Permit does not convey any property rights of any sort, or any exclusive privilege.

XXVI. Severability Clause

Pursuant to 40 CFR 70.6 (a)(5), the provisions of this Permit are severable, and if any provision of this Permit, or the application of any provision of this Permit to any circumstances is held invalid, the application of such provision to other circumstances, and the remainder of this Permit, shall not be affected thereby.

XXVII. Emergency Conditions

Pursuant to 40 CFR 70.6 (g), the Permittee shall be shielded from enforcement action brought for noncompliance with technology based[36] emission limitations specified in this Permit as a result of an emergency[37]. In order to use emergency as an affirmative defense to an action brought for

[36] Technology based emission limits are those established on the basis of emission reductions achievable with various control measures or process changes (e.g., a new source performance standard) rather than those established to attain health based air quality standards.

[37] An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the

noncompliance, the Permittee shall demonstrate the affirmative defense through properly signed, contemporaneous operating logs, or other relevant evidence that:

A. An emergency occurred and that the Permittee can identify the cause(s) of the emergency;

B. The permitted facility was at the time being properly operated;

C. During the period of the emergency, the Permittee took all reasonable steps as expeditiously as possible, to minimize levels of emissions that exceeded the emissions standards, or other requirements in this Permit; and

D. The Permittee submitted notice of the emergency to the DES within two (2) business days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emission, and corrective actions taken.

XXVIII. Permit Deviation

In accordance with 40 CFR 70.6(a)(3)(iii)(B), the Permittee shall report to the DES all instances of deviations from Permit requirements, by telephone, fax, or e-mail (pdeviations@des.state.nh.us) within 24 hours of discovery of such deviation. This report shall include the deviation itself, including those attributable to upset conditions as defined in this Permit, the probable cause of such deviations, and any corrective actions or preventative measures taken.

Within 10 days of discovery of the permit deviation, the Permittee shall submit a written report including the above information as well as the following: preventive measures taken to prevent future occurrences; date and time the permitted device returned to normal operation; specific device, process or air pollution control equipment that contributed to the permit deviation; type and quantity of excess emissions emitted to the atmosphere due to permit deviation; and an explanation of the calculation or estimation used to quantify excess emissions.

Said Permit deviation shall also be submitted in writing to the DES in the semi-annual summary report of monitoring and testing requirements due July 31st and January 31st of each calendar year. Deviations are instances where any Permit condition is violated and has not already been reported as an emergency pursuant to Section XXVII of this Permit.

Reporting a Permit deviation is not an affirmative defense for action brought for noncompliance.

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control of the source, including acts of God, which situation would require immediate corrective action to restore normal operation, and that causes the source to exceed a technology based limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operations, operator error or decision to keep operating despite knowledge of any of these things.

Federal Acid Rain Requirements

XXIX. Phase II Acid Rain Permit Application

The attached Phase II Acid Rain Permit application, dated May 15, 2009, is hereby incorporated by reference into this permit. The Permittee shall comply with the requirements set forth in the Phase II Acid Rain Permit Application and this permit.

XXX. General Acid Rain Provisions

The Permittee shall comply with the applicable provisions of 40 CFR 72, *Permit Regulations*; 40 CFR 73, *Sulfur Dioxide Allowance System*; 40 CFR 75, *Continuous Emission Monitoring*; 40 CFR 76, *Acid Rain Nitrogen Oxides Emission Reduction Program*; and 40 CFR 77, *Excess Emissions*.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☑ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

PSNH MERRIMACK STATION Facility (Source) Name	NH State	2364 Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

STEP 3, Cont'd.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

STEP 3, Cont'd.

Liability, Cont'd.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating
to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name: John M. MacDonald	
Signature John M. MacDonald	Date: May 15, 2009

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ New ☐ Revised ☑ Renewal

STEP 1 Indicate plant name, State, and ORIS code from NADB, if applicable

Plant Name	State	ORIS Code
PSNH MERRIMACK STATION	NH	2364

STEP 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
Type	Cyclone	Cyclone				
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☑	☑	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☐	☐	☐	☐	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging form)	☐	☐	☐	☐	☐	☐

PSNH MERRIMACK STATION
Plant Name (from Step 1)

STEP 2, cont'd.

	ID# 1	ID# 2	ID#	ID#	ID#	ID#
	Type Cyclone	Type Cyclone	Type	Type	Type	Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign & date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

John M. MacDonald Name	
Signature John M. MacDonald	May 15, 2009 Date

ATTACHMENT II

Title V Operating Permit for PSNH Newington Station

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Title V Operating Permit

Permit No: **TV-OP-054**
Date Issued: **March 9, 2007; Administrative Amendment issued on December 17, 2007; Minor Modification issued on January 29, 2010**
This certifies that:
Northeast Utilities
Public Service of New Hampshire
780 North Commercial Street
Manchester, NH 03101

has been granted a Title V Operating Permit for the following facility and location:
Public Service of New Hampshire
Newington Station
165 Gosling Road
Newington, NH
AFS Point Source Number – 3301500054

This Title V Operating Permit is hereby issued under the terms and conditions specified in the Title V Operating Permit Application filed with the New Hampshire Department of Environmental Services on **July 1, 1996** under the signature of the following responsible official certifying to the best of their knowledge that the statements and information therein are true, accurate and complete.

Responsible Official:
John MacDonald
(603) 634-2236
Technical Contact:
Laurel Brown
(603) 634-2331

Designated Representative:
John MacDonald (603) 634-2236
Alternate Designated Representative:
William Smagula (603) 634-2851
Authorized Account Representative:
John MacDonald (603) 634-2236
Alternate Authorized Account Representative:
William Smagula (603) 634-2851

This Permit is issued by the New Hampshire Department of Environmental Services, Air Resources Division pursuant to its authority under New Hampshire RSA 125-C and in accordance with the provisions of the Code of Federal Regulations, Title 40, Part 70.
This Title V Operating Permit shall expire on **March 31, 2012.**

SEE ATTACHED SHEETS FOR ADDITIONAL PERMIT CONDITIONS

For the New Hampshire Department of Environmental Services, Air Resources Division

____

Director, Air Resources Division

TABLE OF CONTENTS

ABBREVIATIONS

AAL	Ambient Air Limit
AP-42	Compilation of Air Pollutant Emission Factors
ARD	Air Resources Division
ASTM	American Society for Testing and Materials
ATS	Allowance Tracking System
BACT	Best Available Control Technology
BHP (or bhp)	Brake Horse Power
BTU	British Thermal Units
CAA	Clean Air Act, 42 U.S.C. § 7401, et seq.
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstracts Service
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DER	Discrete Emission Reduction
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
Env-Wm	New Hampshire Code of Administrative Rules – Waste Management Division
ECS	Emission Control System
ERC	Emission Reduction Credit
ETS	Emissions Tracking System
FR	Federal Register
HAP	Hazardous Air Pollutant
HHV	High Heat Value
HCl	Hydrochloric acid
Hr	Hour
kGal	1,000 gallons
kscfm	1,000 standard cubic feet per minute
KVDC	Kilovolt Direct Current
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
Lb/hr	Pounds per hour
LNB	Low NO_x Burner
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas (Propane)
MACT	Maximum Achievable Control Technology
mg/L	Milligrams per liter
MMBTU (or MMBtu)	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt
NAAQS	National Ambient Air Quality Standard
NATS	NOx Allowance Tracking System
NESHAPs	National Emissions Standards for Hazardous Air Pollutants

ABBREVIATIONS (cont.)

NG	Natural Gas
NHDES (or DES)	New Hampshire Department of Environmental Services
NMOC	Nonmethane Organic Compound
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PCB	Polychlorinated biphenyls
PE	Potential Emission
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmv	part per million by volume
PSD	Prevention of Significant Deterioration
PSI	Pounds per Square Inch
PTE	Potential to Emit
PUC	Public Utilities Commission
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
T-12M	Tons during any consecutive 12-month period
TAP	Toxic Air Pollutant
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

Facility Specific Title V Operating Permit Conditions

I. Facility Description of Operations

Newington Station (Newington) is a fossil fuel-fired electric generating facility, owned and operated by Public Service of New Hampshire (PSNH), a subsidiary of Northeast Utilities. The facility is comprised of one utility boiler, two auxiliary boilers, one emergency generator, two bulk oil storage tanks, and one bulk oil storage day tank. The facility operations also include various activities that are classified as insignificant or exempt activities.

The one utility boiler is capable of burning either natural gas or No. 6 fuel oil or crude oil; the auxiliary boilers burn No. 2 fuel oil; and the emergency generator burns diesel.

The auxiliary boilers provide steam and building heat when the utility boiler is not operating. The utility boiler stack is equipped with a CEMS for NOx, SO_2, and CO and a COMS. Newington emits NOx, SO_2, CO, VOCs, PM, CO_2, RTAPs, and HAPs. Newington has installed control equipment and implemented operational changes to reduce emissions, including electrostatic precipitators to control particulate matter, and burner modifications (also referred to as low NOx burners), overfire air, staged combustion, and water injection, to control NOx emissions.

Newington operates a fly ash reinjection system, as an alternative operating scenario, to capture unburned carbon and to reduce the amount of fly ash shipped off-site as solid waste.

II. Permitted Activities

In accordance with all of the applicable requirements identified in this permit, the Permittee is authorized to operate the devices and or processes identified in Sections III, IV, V and VI within the terms and conditions specified in this Permit.

III. Significant Activities Identification and Stack Criteria

A. Significant Activity Identification

The activities identified in the following table (Table 1) are subject to and regulated by this Title V Operating Permit:

Table 1 – Significant Activity Identification			
Emission Unit Number	Description of Emission Unit	Maximum Gross Heat Input or Maximum Power Output	Maximum Operating Conditions
NT1	Steam Generating Unit 1 (Combustion Engineering Model No. 8269) (Installed 1969) Tangential Firing	Crude oil or No. 6 fuel oil at no more than 2.0% sulfur content by weight, No. 2 fuel oil at no more than 0.4% sulfur content by weight, or natural gas or combination thereof: 4,350 MMBtu/hr gross heat input (nameplate rating)[1]	A) In accordance with New Source Review avoidance, the maximum operating rate shall not exceed 25,235,000 MMBtu total gross heat input during any consecutive 12-month period. This maximum

[1] The heat input rating of 4,350 MMBtu/hr was calculated based upon the nameplate rating of NT1, fuel flow to the boiler, and Btu

Table 1 – Significant Activity Identification			
Emission Unit Number	Description of Emission Unit	Maximum Gross Heat Input or Maximum Power Output	Maximum Operating Conditions
			operating rate may be adjusted upon written approval from DES. B) Toner may be used as an auxiliary fuel in the boiler. The toner feed rate shall not exceed 24 tons/day.
NTAB1	Auxiliary Boiler No. 1A (Erie City Energy Division Model No. 15Mkeystone) (Installed 1969)	No. 2 Fuel Oil with maximum sulfur content of 0.4% by weight: 99.4 MMBtu/hr	A) Maximum fuel consumption rate of No. 2 fuel oil shall not exceed 3.57 million gallons during any consecutive 12-month period.[2] B) This fuel consumption limitation is to limit the NOx emissions to less than 50 tons during any consecutive 12-month period.
NTAB2	Auxiliary Boiler No. 1B (Erie City Energy Division, Model No. 15Mkeystone) (Installed 1969)	No. 2 Fuel Oil with maximum sulfur content of 0.4% by weight: 99.4 MMBtu/hr	A) Maximum fuel consumption rate of No. 2 fuel oil shall not exceed 3.57 million gallons during any consecutive 12-month period.[3] B) This fuel consumption limitation is to limit the NOx emissions to less than 50 tons during any consecutive 12-month period.
NTEG1	Emergency Generator 1 Caterpillar Model # C9 Serial # - S9L01463 Installed December 2007	2.7 MMBtu/hr Diesel[4] - equivalent to 19.4 gal/hr	Operating hours shall be limited to 500 hours during any consecutive 12-month period.

B. Stack Criteria

The following stacks for the above listed significant devices at this facility shall discharge vertically without obstruction (including rain caps) and meet the following criteria:

analysis of the fuel. The CEMS calculates and records the heat input on a minute-by-minute basis according to the procedures in 40 CFR 75. The calculated heat input from the CEMS is based upon the volumetric flow of the stack gases, the CO_2 concentration, and a carbon-based F factor—a default factor provided in 40 CFR Part 75. The calculated heat input rate from the CEMS is not based on fuel flow, except when dual fuels are used.

[2] The heating value of No. 2 fuel oil is assumed to be 140,000 BTU/gallon. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[3] The heating value of No. 2 fuel oil is assumed to be 140,000 BTU/gallon. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[4] The heating value of diesel is assumed to be 137,000 BTU/gallon. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

Table 2 – Stack Criteria				
Stack Number	Emission Unit Number	Emission Unit Description	Minimum Stack Height (Feet) Above Ground Level	Maximum Inside Stack Diameter (Feet)
STNT1	NT1	Steam Generating Unit No. 1	410	20.75
STNTAB1	NTAB1	Auxiliary Boiler No. 1	211	3.5
STNTAB2	NTAB2	Auxiliary Boiler No. 2	211	3.5

Changes to the state-only requirements pertaining to stack parameters (set forth in this permit), shall be permitted only when an air quality impact analysis which meets the criteria of Env-A 606 is performed either by the facility or the New Hampshire Department of Environmental Services, Air Resources Division (if requested by facility in writing) in accordance with the "DES-ARD Procedure for Air Quality Impact Modeling" and approved by DES. All air modeling data shall be kept on file at the facility for review by the DES upon request.

IV. Insignificant Activities Identification

All activities at this facility that meet the criteria identified in Env-A 609.04(d), shall be considered insignificant activities. Emissions from the insignificant activities shall be included in the total facility emissions for the emission-based fee calculation described in Section XXIII. of this Permit.

V. Exempt Activities Identification

All activities identified in Env-A 609.03(c) shall be considered exempt activities and shall not be included in the total facility emissions for the emission based fee calculation described in Section XXIII of this permit.

VI. Pollution Control Equipment/Method Identification

The devices and/or processes identified in Table 3 are considered pollution control equipment or techniques for each identified emissions unit:

Table 3 – Pollution Control Equipment/Method Identification[5]		
Pollution Control Equipment Number	Description of Equipment/Method	Emission Unit Number
NT1-PC1	Electrostatic Precipitator (ESP)	NT1

[5] Note that additional pollution control equipment/method options are included in the alternative operating scenario section.

VII. Alternative Operating Scenarios

While operating under an alternative operating scenario, the Permittee shall comply with all applicable requirements specified in this permit, including, but not limited to, state and federal operational and emission limitations specified in Section VIII.A.through G, monitoring and testing requirements specified in Section VIII. H., recordkeeping requirements specified in Section VIII. I, and reporting requirements specified in Section VIII. J. Pursuant to 40 CFR 70.6 (a)(9), the Permittee shall keep all applicable records pertaining to the alternative operating scenario during such operation. The Permittee shall keep a record of the scenario under which it is operating.

A. Trial Test Burns with Other Fuels (Permit to Operate No. PO-B-1030)

Prior to the use of any fuel other than fuels previously reviewed and approved by the DES, PSNH shall submit a proposal to the DES, which shall include, but not be limited to the following:

1. Type of fuel;
2. Analysis data of the fuel proposed, which shall include proximate and ultimate analysis, volatile and semi-volatile analyses (i.e., EPA Method 8240, 8260, 8250, or 8270) and metals analysis (i.e., Method 3050 and mercury).
3. Specification of baseline operating conditions at Newington Station including fuel feed rate, sulfur content of fuel, ESP operating conditions, and emission values of opacity, SO_2, NOx, particulate, and CO (if applicable);
4. A comprehensive test plan, which shall present the proposed operating conditions for the trial burn, to include but not be limited to the following:
   a) Length of fuel trial;
   b) New fuel rate;
   c) Means of measuring new fuel feed;
   d) Description of new fuel feed process;
   e) New fuel preparations;
   f) Percent moisture of new fuel feed;
   g) Sulfur content of new fuel;
   h) Time table for operation stability;
   i) Existing fuel feed rate;
   j) ESP operating conditions;
   k) Expected emission values of opacity, SO_2, NOx, TSP, and CO;

l) The continuous tracking or operational data prior to the fuel trial, during the fuel trial, and for a short time after the fuel trial. SO_2, NOx, and opacity can be monitored using the existing CEM.

m) A compliance stack test protocol for TSP emissions using Method 1 through 4, Method 5, or a DES approved alternate, when requested by DES.

n) Operational parameters to be monitored and recorded, which shall include, but not be limited to steam flows, boiler temperatures, and oxygen;

o) The effects of the new fuel on flyash characteristics and resulting effect on the ESP operation;

p) The effects of the new fuel on bottom ash characteristics;

q) Specification and description of expected operational and combustion conditions when the trial burn has reached stabilization with the new fuel feed; and

r) A timetable or schedule with approximate dates of the trial test burn.

5. Based on information regarding the proposed trial fuel burn provided by PSNH, DES may request additional specific information on the proposed trial burn operations. In addition, metal emission stack testing may be required dependent upon DES review of the new fuel metal analysis.

6. If the new fuel is to be consumed on a regular basis, PSNH must apply for a temporary permit. As part of the temporary permit review process, DES will make a determination as to the applicability of the New Source Review and Prevention of Significant Deterioration programs, and will provide an opportunity for public notice and comment.

7. DES shall respond within 30 days of receipt of a proposal with approval, conditional approval, denial, or request for additional information.

8. DES Waste Management Division may have additional requirements and concerns and shall be contacted by PSNH prior to the initiation of any trial fuel burn.

9. A summary report shall be submitted to DES within 60 days after the end of the trial fuel burn, which should include a summary of operational results and trends, emission values to include CEM and stack test data, if performed, and proposed future use of fuel.

B. Fuel Blending Requirements (State Enforceable Only) (Permit to Operate No. PO-B-1030)

DES grants PSNH a waiver from Env-A 1604 in order to purchase oil containing sulfur greater than 2.0% by weight. This oil shall be used for blending purposes only. PSNH shall comply with the requirements listed below when purchasing oil greater than 2.0% sulfur.

1. Delivery of greater than 2.0% sulfur oil shall be to segregated storage tanks.

2. Greater than 2.0% sulfur oil shall be mixed with less than 2.0% sulfur oil in a tank in which the "sparging system" shall be in full operation to assure complete mixing of the blended oil.

3. After mixing for an appropriate amount of time to assure complete blending, samples from the top, middle, and bottom of the tank shall be collected and analyzed in accordance with method ASTM D 4294. The sample results shall be averaged to create a composite figure in accordance with PSNH procedures.

4. After sampling is complete and the test results indicate that the tank of blended oil is less than 2.0% sulfur by weight, the oil may be transferred to the Newington day tank.

5. PSNH shall not burn oil containing greater than 2.0% sulfur by weight.

6. Prior to accepting any shipment of oil containing greater than 2.0% sulfur by weight, PSNH shall contact DES by fax or telephone.

7. PSNH shall provide DES with all analytical data from samples collected from all blending operations that utilize greater than 2.0% sulfur by weight oil. This data shall provide DES with specific sulfur analysis information on the oil feeding the boilers and confirm that each blend is less than or equal to 2.0% sulfur by weight.

C. Fly Ash Reinjection (Permit to Operate No. PO-B-1030)

1. To capture unburned carbon in the fly ash and to reduce the amount of ash shipped off-site as solid waste, PSNH is authorized to maintain and operate the fly ash injection system.

2. The fly ash injection system is comprised of a system of blowers and piping that allow fly ash from the precipitator hoppers to be reinjected into the burners of the boilers.

3. To minimize PM emissions during fly ash reinjection, PSNH shall ensure that the ESP is energized before start-up of the fly ash reinjection system.

D. NOx Emission Reduction Management Practices (Permit to Operate No. PO-B-1030, NOx RACT Orders Nos. ARD-97-001 and ARD-98-001, and Env-A 1211)

1. To achieve the NOx emission requirements specified in this permit, PSNH is authorized to maintain and operate any or all of following equipment, systems and methods: the overfire air system, water injection, and the low NOx burners.

2. The CEMS shall be used to determine the NOx emissions from Unit No. 1.

3. The overfire air system is comprised of ports, ducts, and dampers that allows the combustion airflow to be diverted from the top of the windbox through ports located above the top elevation of burners.

4. The water injection system is comprised of nozzles that inject water into the flame to reduce peak flame temperature.

5. The low NOx burners are designed to create lower NOx emissions during the combustion of fuel.

6. PSNH shall maintain compliance with the NOx emission limitations listed in Section VIII. B, D, E, and F during the usage of any of these alternative NOx emission reduction methods.

7. PSNH shall record which NOx emission reduction management practice is in use and when a change in scenario occurs.

8. PSNH shall maintain records according to Section VIII. I and submit reports according to Section VIII. J.

E. Auxiliary Fuel – Toner (Permit to Operate No. PO-B-1030) (State Enforceable)

Toner may be used as an auxiliary fuel. The combustion of the toner shall be performed under the following conditions:

1. The toner feed rate shall not exceed 24 tons/day or a rate to ensure compliance with Env-A 1400, whichever is less.

2. PSNH shall ensure compliance with all federal and state air quality and waste management requirements pertaining to the combustion of toner.

3. Combustion of toner shall not occur during start-up or shutdown conditions.

4. Combustion of toner shall be ceased immediately upon indication of abnormal operating conditions or any condition that threatens compliance with this permit or any air quality regulation or requirement.

5. The toner shall be stored in containers with proper fire precautions observed.

6. The toner shall be handled and transferred in such a manner as to minimize fugitive dust emissions.

7. PSNH shall retain on-site the following information:

   a) Name and address of the company providing the toner;

   b) Amount of toner combusted; and

   c) RTAP compliance demonstration.

8. When a new toner is combusted, PSNH shall notify DES in the semi-annual reporting.

9. PSNH shall conduct an RTAP evaluation to determine compliance for each new toner and retain it along with a copy of the Material Safety Data Sheet (MSDS) on-site for inspection by DES, upon request.

VIII. Applicable Requirements

A. State-only Enforceable Operational and Emission Limitations

The Permittee shall be subject to the state-only operational and emission limitations identified in Table 4 below.

Table 4 - State-Only Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
1.	Env-A 1403	All devices subject to RSA 125-I and Env-A 1400	All devices or processes subject to RSA 125-I and Env-A 1400 shall comply with Env-A 1400 *(Regulated Toxic Air Pollutants).*
2.	Env-A 1403.01(d)	All devices subject to RSA 125-I and Env-A 1400	Documentation for the demonstration of compliance shall be retained at the facility and shall be made available to DES for inspection upon request.
3.	Env-A 1404.01	All devices subject to RSA 125-I and Env-A 1400	A) The owner of a new or modified device or process requiring a permit under this chapter shall submit an application for a temporary permit in accordance with Env-A 607.03. B) Pursuant to RSA 125-I:5,I, the owner shall not operate the device or process until a temporary permit is issued.
4.	Env-A 1405.01	All devices subject to RSA 125-I and Env-A 1400	The owner of any device or process subject to RSA 125-I and Env-A 1400 shall determine compliance with the AAL by using one of the methods provided in Env-A 1405. Upon request, the owner of any device or process subject to RSA 125-I and Env-A 1400 shall provide documentation of compliance with the AAL to DES.
5.	Env-A 1605.01 Sulfur Content for Gaseous Fuels[6]	NT1	The sulfur content of gaseous fuels shall not exceed 15 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure.

B. Federally Enforceable Operational and Emission Limitations

1. The Permittee shall be subject to the emission limitations summarized in Table 5 below for the listed fuel burning devices.

[6] Env-A 1605 contains the most current requirement for the sulfur content of gaseous fuels. Env-A 1605 is state enforceable only because it is not included in New Hampshire's State Implementation Plan (SIP). 40 CFR 52.1520 contains the New Hampshire rules that have been approved by EPA and adopted as part of the SIP. Env-A 402.03, effective on December 27, 1990, lists the federally enforceable sulfur limit for gaseous fuels because it was adopted as part of the SIP on September 14, 1992. Upon approval by EPA and adoption into New Hampshire's SIP, Env-A 1605 will supercede Env-A 402.03, which will expire.

Table 5 – Summary of Emission Limitations				
Item No.	Pollutant	NT1	NTAB1	NTAB2
1.	SO_2 Emissions Cap for Schiller Station, Merrimack Station and Newington Station combined	55,150 tons per calendar year	NA	NA
2.	NOx	0.35 lb/MMBtu based on a 24-hour calendar day average with oil[7]; 0.25 lb/MMBtu based on a 24-hour calendar day average with oil/gas	0.20 lb/MMBtu based on a 24-hour calendar day average; 50 tons per consecutive 12-month period	0.20 lb/MMBtu based on a 24-hour calendar day average; 50 tons per consecutive 12-month period
3.	CO	0.231 lb/MMBtu based on a 24-hour calendar day average; 2915 tons per consecutive 12-month period	NA	NA
4.	TSP	0.22 lb/MMBtu	0.41 lb/MMBtu	0.41 lb/MMBtu
5.	Opacity	40% for any continuous 6-minute period	40% for any continuous 6-minute period	40% for any continuous 6-minute period

2. The Permittee shall be subject to the federally enforceable operational and emission limitations identified in Table 6 below:

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
1.	Env-A 1211.03(c)(3)(c) NOx RACT for Utility Boilers	NT1	A) When firing oil, the Permittee shall be limited to 0.35 lb NOx/MMBtu, based on a 24-hour calendar day average[8]. B) When firing gas or any combination of oil and gas, the Permittee shall be limited to 0.25 lb NOx/MMBtu heat input based on a 24-hour calendar day average. C) If both a combination of gas and oil and exclusively oil are burned for separate periods within the same 24-hour calendar day, the applicable emission limit shall be a prorated value using the emission limits specified in Conditions B and C above and the actual hour that each

[7] Note that 0.35 lb/MMBtu based on a 24-hour calendar day average is equivalent to 4,416.1 tons per consecutive 12-month period based on an annual heat input of 25,235,000 MMBtu and 0.35 lb/MMBtu.

[8] Note that 0.35 lb/MMBtu based on a 24-hour calendar day average is equivalent to 4,416.1 tons per consecutive 12-month period based on an annual heat input of 25,235,000 MMBtu and 0.35 lb/MMBtu

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
			fuel type is burned as indicated in the following equation: $$AEL = \frac{(t_{og} * 0.25lb/MMBtu) + (t_o * 0.35lb/MMBtu)}{t_{og} + t_o}$$ Where: AEL=allowable NOx emission limit (in lb/MMBtu) t_{og}=Number of hours within 24-hour calendar day when burning any combination of gas and oil t_o=Number of hours within 24-hour calendar day when burning exclusively oil
2.	State Permit to Operate No. PO-B-1030 and Env-A 1604.01(c)(2) Fuel Specifications for No. 6 Fuel Oil and Crude Oil	NT1	The sulfur content of No. 6 fuel oil and crude oil shall not exceed 2.00 percent sulfur by weight.
3.	State Permits to Operate Nos. PO-B-1030, PO-B-1031, PO-B-1032 and Env-A 1604.01(a) Fuel Specifications for No. 2 Fuel Oil	NT1, NTAB1, NTAB2	The sulfur content of No. 2 fuel oil shall not exceed 0.40 percent by weight.
4.	40 CFR 52.1520[9] Sulfur Content for Gaseous Fuels	NT1, NTAB1, NTAB2	The sulfur content of gaseous fuels shall not exceed 5 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure.
5.	State Permit to Operate No. PO-B-1030	NT1	PSNH shall use No. 2 fuel oil or natural gas to start-up the boiler.
6.	State Permit to Operate No. PO-B-1030 Maximum Gross Heat Input	NT1	A) The maximum operating rate of this electric generating unit is limited to 4,350 MMBtu/hr (nameplate rating)[10] gross heat input of crude oil or No. 6 fuel oil at not more than 2.0% sulfur content by weight, No. 2 fuel oil at not more than 0.4% sulfur content by weight or natural gas or any combination thereof.

[9] 40 CFR 52.1520 contains the New Hampshire rules that have been approved by EPA and adopted as part of the State Implementation Plan (SIP). Env-A 402.03, effective on December 27, 1990, contained the sulfur limit for gaseous fuels was adopted as part of the SIP on September 14, 1992. Env-A 402.03 and is still considered to be federally enforceable until such time as the SIP is amended and approved by the EPA. This requirement will expire at such time that Env-A 1605, the amended rule containing the sulfur content limit for gaseous fuels, is approved by EPA and adopted as part of the SIP.

[10] The heat input rating of 4,350 MMBtu/hr was calculated based upon the nameplate rating of NT1, fuel flow to the boiler, and Btu analysis of the fuel. The CEMS calculates and records the heat input on a minute-by-minute basis according to the procedures in 40 CFR 75. The calculated heat input from the CEMS is based upon the volumetric flow of the stack gases, the CO_2 concentration, and a carbon-based F factor—a default factor provided in 40 CFR Part 75. The calculated heat input rate from the CEMS is not based on fuel flow.

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
			B) In accordance with NSR avoidance for CO, the maximum operating rate shall not exceed 25,235,000 MMBtu total gross heat input during any consecutive 12-month period. Upon written approval from DES, PSNH may adjust the maximum operating rate provided that PSNH would not exceed the emission limitations established in the permit.
7.	State Permit to Operate No. PO-B-1030 and Env-A 404.01 State Acid Deposition Control Program	NT1	The total SO_2 emissions from Newington Station's Unit No. 1 (NT1), Schiller Station, and Merrimack Station shall not exceed 55,150 tons per calendar year.
8.	State Permits to Operate Nos. PO-B-1030 and Env-A 2002.01 and 2002.04 (b) Visible Emission Standard for Fuel Burning Devices	NT1	During normal operation, the average opacity shall not exceed 40 percent for any continuous 6-minute period. The 6-minute time blocks shall be established to provide for ten 6-minute blocks per calendar hour. The first 6-minute time block in any calendar hour in excess of the opacity standard will not be considered an excess emission. Any subsequent time block in the same calendar hour in exceedance of the opacity standard shall be considered an excess emission. To be considered an excess emission, the subsequent time block in the same calendar hour in excess of the opacity standard does not have to be consecutive in occurrence with the first exceedance. The average opacity may exceed 40 percent for a non-overlapping set or sets of time up to 60 minutes in any 8-hour period during startup, shutdown, malfunction, soot blowing, grate cleaning, and cleaning of fires.
9.	State Permits to Operate Nos. PO-B-1031, PO-B-1032 and Env-A 2002.01 and 2002.04 (c) Visible Emission Standard for Fuel Burning Devices	NTAB1, NTAB2	The average opacity shall not exceed 40 percent for any continuous 6-minute period. The average opacity may exceed 40 percent for one period of 6 continuous minutes in any 60 minute period during startup, shutdown, malfunction, soot blowing, grate cleaning, and cleaning of fires.
10.	State Permit to Operate No. PO-B-1030, and Env-A 2002.06(c)(2) Particulate Emission Standards	NT1	PSNH shall not cause or allow emissions of particulate matter in excess of the following equation at the utility boiler: $E = 0.880 * I^{-0.166}$ Where: E=maximum allowable particulate matter emission rate in lb/MMBtu = 0.22 lb/MMBtu I=maximum gross heat input rate in MMBtu/hr = 4,350 MMBtu/hr This limitation is independent of fuel type and applies at all times, including during flyash reinjection.
11.	State Permit to Operate PO-B-1030	NT1	A) PSNH shall not exceed a CO emission rate of 0.231 lb/MMBtu for any 24-hour calendar day average as calculated by the CEMs. This limitation is independent of fuel type and applies at all times.

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
			B) PSNH shall not exceed an annual CO emission rate of 2,915 tons per consecutive 12-month period based upon 0.231 lb/MMBtu and the New Source Review limited maximum annual operating rate of 25,235,000 MMBtu/year. As long as the daily and annual CO emission rates are not exceeded, the maximum annual operating rate is not a permit limitation.
12.	State Permit to Operate No. PO-B-1030 ESP Operating Requirements	NT1	A) PSNH shall maintain and operate the ESP system for the control of particulate matter, in accordance with the manufacturer's recommendations. B) The ESP unit shall be operational at all times that the facility is in operation above 120 MW on any combination of oil and oil/gas. The ESP will not normally be energized when the unit is burning 100 percent natural gas. C) The inlet temperature of the ESP as measured at the outlet of the boiler shall not exceed 785°F. D) The secondary voltage of the transformer rectifier sets (TR sets) is automatically controlled to operate between a maximum of 45 KVDC and a minimum of 7500 VDC based on the dust loading rate, spark rate, and opacity. E) PSNH shall optimize the ESP based on the opacity baseline for high load service. F) PSNH shall track the fields out of service. G) PSNH shall continuously operate and maintain the ESP system to minimize particulate matter emissions, to meet permit conditions, and to maintain compliance with Env-A 2000. The operation and maintenance shall include the normal procedures for scheduled checking and cleaning of the hoppers and transport lines. All maintenance procedures performed and corrective actions taken on the ESP system shall be recorded. The records shall be maintained at the facility and shall be made available for review at the request of the DES. All deviations from the operation criteria described above and the corrective actions taken shall be recorded in the work management system or logbook.
13.	State Permit to Operate PO-B-1030 New Source Review Avoidance	NT1	A) PSNH avoided NSR when adding the natural gas firing capabilities on the basis that the emissions would not increase. B) If an emissions increase occurs in the maximum 24-hour calendar day average emission rate (calculated in lb/MMBtu) of any pollutant as determined in accordance with 40 CFR 60.14 and by DES when burning natural gas, then the natural gas conversion shall be subject to NSPS. C) If an emissions increase occurs in the actual annual emissions of any pollutant as determined in accordance with 40 CFR 51.165, 40 CFR 52.21 or by DES, then the natural gas conversion shall be subject to NSR. D) PSNH shall not exceed the 24-hour calendar day average emission rates of CO (0.231 lb/MMBtu) and NOx (0.25 lb/MMBtu for oil/gas and 0.35 for oil) as specified above. The maximum annual operating rate of 25,235,000 MMBtu/year was used to calculate the applicable CO emission permit limits, which will be enforced through the annual CO

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
			emission limit by DES to protect the annual baseline emission limits for CO. The maximum annual operating rate referred to herein may be adjusted by PSNH provided that the resulting emissions will not contribute significantly to or cause a violation of any applicable NAAQS, or a violation of any applicable PSD increment, or a violation of the NH State Implementation Plan, or a violation of any condition contained in a permit issued pursuant to regulations approved or promulgated under the CAA. Regardless of the maximum annual operating rate, the emission limitations established in this permit shall not be exceeded. E) Any adjustments, requested by PSNH, to the maximum NOx and CO emission limits and the maximum operating rate referred to herein will be made only after DES' review of applicable supporting data. Any adjustments made shall not result in an increase of emissions. Adjustments shall not be made until PSNH has received written approval from DES.
14.	State Permit to Operate PO-B-1030	NT1	PSNH shall follow standard operating procedures for cold boiler start-up and boiler repair practices to ensure compliance with opacity standards.
15.	40 CFR 72, 73, and 77 Acid Rain Provisions	NT1	PSNH shall comply with the applicable Federal Acid Rain Program provisions.
16.	Env-A 1211.12 NOx RACT for Auxiliary Boilers	NTAB1, NTAB2	A) Each auxiliary boiler shall be limited to a NOx RACT emission limit of 0.20 lb/MMBtu based on a 24-hour calendar day average, regardless of the type of fuel burned. B) The emissions from all auxiliary boilers shall be included in the calculation of both the actual and theoretical potential emissions from the stationary source.
17.	State Permits to Operate Nos. PO-B-1031, PO-B-1032 Maximum Fuel Consumption	NTAB1, NTAB2	A) Maximum fuel consumption rate of No. 2 fuel oil for each device shall not exceed 3.57 million gallons during any consecutive 12-month period.[11] B) This fuel consumption limitation is to limit the NOx emissions to less than 50 tons during any consecutive 12-month period.
18.	Env-A 2002.06 (c)(2) Particulate Emission Standards	NTAB1, NTAB2	PSNH shall not cause or allow emissions of particulate matter in excess of the following equation at each of the auxiliary boilers: $E = 0.880 * I^{-0.166}$ Where: E=maximum allowable particulate matter emission rate in lb/MMBtu = 0.41 lb/MMBtu I=maximum gross heat input rate in MMBtu/hr = 99.4 MMBtu/hr
19.	Env-A 1211.01(j)(1) & 40 CFR 60.4211(e)	NTEG1	*Emergency Generators* The emergency generator shall be limited to the following in any consecutive 12-month period: a. 100 hours for readiness testing and maintenance checks; and

[11] The heating value of No. 2 fuel oil is assumed to be 140,000 BTU/gallon. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
			b. 500 hours of emergency operation.
20.	Env-A 2002.02 and 2002.04(c) Visible Emission Standard for Fuel Burning Devices	NTEG1	The average opacity shall not exceed 20 percent for any continuous 6-minute period. The average opacity may exceed 20 percent for one period of 6 continuous minutes in any 60 minute period during startup, shutdown and malfunction.
21.	Env-A 2002.08 Particulate Emission Rate	NTEG1	The particulate matter emissions from fuel burning devices installed on or after January 1, 1985 shall not exceed 0.3 lb/MMBtu.[12]
22.	Env-A 1002 Fugitive Dust	Facility wide	The Permittee shall take precautions, such as wetting, covering, shielding or vacuuming, to prevent, abate, and control fugitive dust emissions during any activity, which might create fugitive dust. Such activities include bulk hauling activities, including the transportation and transfer of mineral material over public roads and maintenance activities, including sweeping, vacuuming, or other activity involved with the upkeep of roads or parking lots.
23.	40 CFR 68 and 1990 CAA Section 112(r)(1) Accidental Release Program Requirements	Facility wide	The Permittee maintains no quantities of regulated substances above the threshold quantities established by the EPA under 40 CFR 68.130. Administrative controls will be established by the Permittee in order to ensure that inventories of regulated substances are maintained below the specified threshold quantities. The facility is subject to the Purpose and General Duty clause of the 1990 Clean Air Act, Section 112(r)(1). General Duty includes the following responsibilities: (A) Identify potential hazards that may result from such releases using appropriate hazard assessment techniques; (B) Design and maintain a safe facility; (C) Take steps necessary to prevent releases; and (D) Minimize the consequences of accidental releases that do occur. If, in the future, the Permittee wishes to store quantities of regulated substances above the threshold levels, a risk management plan shall be submitted to the Part 68 implementing agency prior to exceeding threshold quantity levels in a timely manner.
24.	40 CFR 61 Subpart M, Env-A 504.01(e) and Env-A 1800 Asbestos Management and Control	Facility wide	PSNH shall comply with the asbestos requirements of Env-A 1800 and 40 CFR 61.145 during demolition and/or renovation.
25.	40 CFR 60.4207 (NSPS Subpart IIII)	NTEG1	<u>*Maximum Sulfur Content Allowable in Liquid Fuels*</u> a. The sulfur content of diesel fuel burned in the emergency generator shall not exceed 500 ppm (0.05 percent sulfur by weight); and b. After October 1, 2010, the sulfur content of diesel fuel burned in the emergency generator shall not exceed 15 ppm (0.0015 percent sulfur by weight).

[12] PSNH shall demonstrate compliance with this requirement by using an EPA-approved emission factor and EPA/DES approved heat input content (Btu/gallon). This calculation shall be maintained on file at the facility.

Table 6 – Federally Enforceable Operational and Emission Limitations			
Item No.	Regulatory Cite	Applicable Emission Unit	Applicable Requirement
26.	Env-A 1211.02(o)	NTEG1	*Emergency Generator* The emergency generator shall only operate: a. As a mechanical or electrical power source when the primary power source for the Facility has been lost during an emergency such as a power outage; or b. During normal maintenance and testing as recommended by the manufacturer.

C. Annual SO_2 Allowance Programs (40 CFR 72, 40 CFR 73, Env-A 611.07, and Env-A 2900)

1. SO_2 Allowance Allocation

a) In accordance with 40 CFR Part 73, SO_2 allowances pursuant to the Federal Acid Rain Program for this facility are allocated as indicated in the following table:

Table 7 – SO_2 Allowance Allocation (tons)								
	2003	2004	2005	2006	2007	2008	2009	2010
NT1	11,660	11,660	11,660	11,660	11,660	11,660	11,660	10,613

b) Pursuant to Env-A 2906.02 [State enforceable only], *Allocation of SO_2 Allowances*, for 2007 and subsequent years, PSNH's Schiller, Merrimack and Newington (NT1) Stations shall transfer the SO_2 Allowances allocated pursuant to the Federal Acid Rain Program to DES, and DES shall transfer SO_2 allowances (7,289 tons) calculated pursuant to Env-A 2900 plus any potential bonus allowances calculated pursuant to Env-A 2906.07, Bonus Allocation of SO_2 Allowances back to PSNH's Schiller, Merrimack, and Newington stations. The amount of SO_2 Allowances allocated to PSNH Newington shall be determined according the methodology in Env-A 2906.05, *Allowance Allocation Methodology*.

2. Compliance

a) Pursuant to 40 CFR 73.35, the Permittee shall comply with the SO_2 emission limitation requirements.

b) At the end of each calendar year, the Permittee shall hold sufficient SO_2 allowances equivalent to the SO_2 emissions during that calendar year.

3. General Provisions

Pursuant to Env-A 611.07 and Env-A 2900, SO_2 allowances lawfully held or acquired by the Permittee shall be governed by the following:

a) Emissions from the affected units shall not exceed any SO_2 allowances held by the affected unit;

b) The number of SO_2 allowances held by the Permittee shall not be limited;

c) The Permittee shall not use SO_2 allowances to avoid compliance with any other applicable requirement of either state or federal rules or of the provisions of the Clean Air Act; and

d) Any SO_2 allowances held by the Permittee shall be accounted for according to the procedures established in the applicable provisions of 40 CFR 72, 40 CFR 73, and 40 CFR 76.

4. Excess Emissions

Pursuant to 40 CFR 72.9(e), if the Permittee has excess emissions, the Permittee shall submit a proposed offset plan as required under 40 CFR 77 and pay the penalty and any interest without demand pursuant to 40 CFR 77. Additional penalties may apply pursuant to Env-A 2900. See Condition VIII. F.8.

5. Allowance Transfer

The Permittee shall transfer allowances according to the procedures in 40 CFR 73.50.

D. Ozone Season NOx Budget Trading Program (Env-A 3200)

1. NOx Allowance Allocation

a) Pursuant to Env-A 3207.03, *Allocation of Allowances,* the amount of NOx allowances allocated to PSNH shall be as set forth in the Table 8 below for the 2003, 2004, and 2005 control periods (ozone seasons of May 1 through September 30):

Table 8 – NOx Allowance Allocation for the Ozone Season (tons)			
Emission Unit	2003	2004	2005
NT1	579	507	434

2. The NOx allowances shall be allocated to PSNH for the 2006 control period (ozone season) and subsequent control periods according to the methodology in Env-A 3207.04, *Future Allowance Allocation Methodology.*

3. Ozone Season NOx Emissions Cap

   a) Pursuant to Env-A 3200, PSNH shall not emit NOx emissions during any control period in excess of the amount of NOx allowances held in PSNH's NATS compliance account for that control period as of the allowance transfer deadline of November 30.

   b) Pursuant to Env-A 3200, PSNH may obtain additional NOx allowances to comply with the NOx Budget Program.

4. Allowance Transfer and Use

   a) Pursuant to Env-A 3209.01, *Marketable Emissions Authorization*, an allowance shall be a marketable emissions authorization that may be bought, sold, or traded at any time during any year, not just the current year.

   b) Pursuant to Env-A 3209.02, *Limited Authorization,* an allowance shall only be used for compliance with the NOx Budget Program in a designated compliance year by being in a compliance account as of the allowance transfer deadline of November 30, or by being transferred into the compliance account by an allowance transfer submitted by the allowance transfer deadline.

   c) PSNH shall comply with the NOx allowance transfer and use provisions pursuant to Env-A 3209, *Allowance Transfer and Use.*

   d) Pursuant to Env-A 3209.09, *Price Disclosure,* subject to a claim of confidentiality in accordance with Env-A 103, PSNH shall make available to any person, all information regarding transaction cost and allowance price.

5. Allowance Banking

   a) Pursuant to Env-A 3210.01, *Retention of Unused Allowances,* the banking of allowances shall be permitted to allow the retention of unused allowances from one year to a future year in either a compliance account, an overdraft account, or a general account.

   b) Pursuant to Env-A 3210.02, *Account Designation,* unless otherwise permitted pursuant to Env-A 3210.04, *Early Reduction Allowances,* unused allowances as of the end of the allowance transfer deadline shall be retained in the compliance, overdraft, or general account and designated as banked allowances after the NATS administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to Env-A 3215, *End-of-Season Reconciliation.*

c) PSNH shall comply with the NOx allowance banking provisions pursuant to Env-A 3210, *Allowance Banking*.

6. End-of-Season Reconciliation

a) Pursuant to Env-A 3206.01, *Limited Authorization*, PSNH shall, no later than November 30 of each calendar year, hold respective a quantity of NOx allowances in PSNH Newington's current year NATS account that is equal to or greater than the total NOx emitted from PSNH Newington during the period May 1 through September 30 of the subject year.

b) PSNH shall determine compliance and reconcile allowances by November 30 of each year for the control period of that year pursuant to Env-A 3215.

7. Authorized Account Representative (Env-A 3211.04)

a) Only the AAR or alternate AAR shall request transfers of allowances in a NATS account.

b) The AAR or alternate AAR shall be responsible for all transactions and reports submitted to the NATS.

c) The alternative AAR shall have the same authority as the primary representative, however, all correspondence from the NATS administrator shall be directed to the primary AAR.

d) Pursuant to Env-A 3211.05 (f), PSNH shall replace an AAR by submitting a revised Account Certificate of Representation to the NATS administrator along with the information contained in Env-A 3211.05(b) and (c) and the name of the AAR who is being replaced.

8. Conversion of Allowances to DERs

Pursuant to Env-A 3207.05, PSNH Newington may convert unused allowances to DERs in accordance with Env-A 3206.02(e) for use as NSR offsets during the ozone season and the procedures for DER generation pursuant to Env-A 3103. Upon conversion, PSNH Newington shall surrender those converted allowances as if they had been used for actual emissions. Under no other circumstances shall unused allowances be converted to, or used as, DERs or ERCs.

9. Prohibition on Property Rights (Env-A 3207.07)

a) Neither an allowance nor any future allocations, which are subject to modification by DES, shall constitute a security or other form of property.

b) An allowance shall not be used prior to the control period for which the allowance is allocated.

10. Excess Emissions and Enforcement Provisions (Env-A 3217)

a) If emissions exceed the allowances held by PSNH Newington by the allowance transfer deadline (November 30), the NATS administrator shall automatically deduct three tons of allowances from the next control period for every ton of excess emissions from PSNH Newington compliance account or overdraft account.

b) In accordance with RSA 125-J:4-a, for purposes of enforcement of the NOx Budget Program, in determining the number of days of violation, any excess emissions for the control period shall presume that each day in the control period of 153 days, constitutes a day in violation unless PSNH Newington can demonstrate, through use of verifiable emissions data that a lesser number of days should be considered. In addition, each ton of excess emissions shall constitute a separate violation.

E. Non-Ozone Season NOx Allowance Program (NOx RACT Order No. ARD-98-001)

Pursuant to NOx RACT Order No. ARD-98-001, PSNH's Schiller, Merrimack, and Newington stations shall comply with a NOx emissions cap of 8208 tons for the non-ozone season beginning on October 1 and ending on April 30. Ozone season DERs and non-ozone season DERS may be used to comply with this non-ozone season limit. Previously generated (1995 through 1998) DERs may be used to comply with this emissions cap. DERs may be generated from PSNH's Newington and Schiller Stations, in accordance with the protocols submitted by PSNH to comply with this emissions cap.

F. Multiple Pollutant Annual Budget Trading and Banking Program (Env-A 2900) [State Enforceable Only]

1. SO_2 Allowance Allocation

Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, DES shall allocate SO_2 Allowances to PSNH Newington according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology* for 2007 and subsequent years.

2. NOx Allowance Allocation

a) Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, DES shall allocate NOx Allowances to PSNH Newington according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology* for 2007 and subsequent years.

b) Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, for 2007 and subsequent years, DES shall calculate the difference between the annual NOx budget (no more than 3,644 tons) and the ozone season NOx allowances allocated pursuant to Env-A 3200.

c) Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, for 2007 and subsequent years, DES shall allocate annual NOx allowances equivalent to the difference between the annual NOx budget and the ozone season NOx allowances to PSNH's Schiller, Merrimack, and Newington stations.

3. CO_2 Allowance Allocation

Pursuant to Env-A 2900, *Multiple Pollutant Annual Budget Trading and Banking Program*, and subsequent revisions, DES shall allocate CO_2 Allowances to PSNH Newington according to the methodology in Env-A 2906.05, *Allowance Allocation Methodology* for 2007 and subsequent years.

4. Allowance Transfer and Use

a) Pursuant to Env-A 2907.01, *Marketable Emissions Authorization*, an allowance shall be a marketable emissions authorization that may be bought, sold, or traded at any time during any year, not just the current year.

b) Pursuant to Env-A 2907.02, *Limited Authorization,* an allowance shall only be used for compliance with the Multiple Pollutant Annual Budget Trading and Banking Program in a designated compliance year by being in a compliance or overdraft account as of the allowance transfer deadline, or by being transferred into the compliance account by an allowance transfer submitted by the allowance transfer deadline.

c) PSNH shall comply with the allowance transfer and use provisions pursuant to Env-A 2907, *Allowance Transfer and Use,* and Env-A 2909, *Allowance Tracking System.*

d) Pursuant to Env-A 2907.08, *Price Disclosure,* subject to a claim of confidentiality in accordance with Env-A 103, PSNH shall make available to any person, all information regarding transaction cost and allowance price.

e) Pursuant to Env-A 2907.09, *Use of Allowances by Utilities,* and RSA 125-J:5, X, the use of allowances by a utility as defined in RSA 362:2, shall be subject to such additional conditions as ordered pursuant to applicable law by the PUC.

5. Allowance Banking

a) Pursuant to Env-A 2908.01, *Retention of Unused Allowances,* the banking of allowances shall be permitted to allow the retention of unused allowances from one year to a future year in either a compliance account, an overdraft account, or a general account.

b) Pursuant to Env-A 2908.02, *Account Designation,* unless otherwise permitted pursuant to Env-A 2909.03, *General Accounts,* unused allowances as of the end of the allowance transfer deadline shall be retained in the compliance, overdraft, or general account and designated as banked allowances after the ATS administrator has made all deductions for a given year from the compliance account or overdraft account pursuant to Env-A 2913, *Compliance Certification.*

c) Pursuant to Env-A 2908.03, *Bonus Early Allowances*, bonus early allowances shall be eligible for a one-time conversion to allowances in 2007. Bonus early allowances that are converted to allowances shall not be used as VERs, ERCs, or DERs.

6. Authorized Account Representative (Env-A 2909.04)

a) Only the AAR or alternate AAR shall request transfers of allowances in an ATS account.

b) The AAR or alternate AAR shall be responsible for all transactions and reports submitted to the ATS.

c) The alternative AAR shall have the same authority as the primary representative, however, all correspondence from the ATS administrator shall be directed to the primary AAR.

d) Pursuant to Env-A 2909.05 (f), PSNH shall replace an AAR by submitting a revised Account Certificate of Representation to the ATS administrator along with the information contained in Env-A 2909.05(b) and (c) and the name of the AAR who is being replaced.

7. End-of-Season Reconciliation

a) Pursuant to Env-A 2904.01, *Limited Authorization*, PSNH shall, no later than January 30 of each calendar year, hold respective quantities of SO_2, NOx, and CO_2 in the PSNH Newington's respective ATS accounts equal to or greater than the respective total SO_2, NOx, and CO_2 emitted from PSNH Newington during the previous year.

b) Pursuant to Env-A 2912.01, *Determination of Compliance*, monitored emissions data as reported by PSNH to the ETS administrator, and as adjusted by the administrator to be in accordance with Env-A 2910, *Emissions Monitoring*, combined with allowance allocations and transfers recorded in the ATS, shall provide the basis for a determination of compliance.

c) PSNH shall determine compliance and reconcile allowances by January 30 of each year beginning in 2008 pursuant to Env-A 2913.

d) Pursuant to Env-A 2912.02, *Request for Deduction of Allowances*, no later than January 30, the AAR shall request the ATS administrator to deduct previous year allowances from the compliance account or overdraft account equivalent to the number of available allowances to cover the emissions during the previous year. The AAR shall identify the compliance account or overdraft account from which the deductions shall be made and shall identify the serial number of the allowances to be deducted. If the AAR does not specify a serial number, allowances useable for that compliance year shall be deducted in the order of their arrival into PSNH Newington's account, with allocated allowances being deducted first, followed by the deduction of transferred allowances.

e) Pursuant to Env-A 2912.04, *Procurement of Additional Allowances,* if the emissions of PSNH Newington in the previous year exceed the allowances in PSNH Newington's compliance account and overdraft account, PSNH Newington shall obtain additional allowances by January 30 so that the total number of allowances in PSNH Newington's compliance account and overdraft account, including allowance transfers properly submitted to the ATS administrator by January 30, equals or exceeds the previous year annual emissions rounded to the nearest whole ton.

8. Excess Emissions and Enforcement Provisions (Env-A 2914)

    a) If emissions exceed the allowances held by PSNH Newington by the allowance transfer deadline (January 30), the Allowance Tracking System administrator shall automatically deduct three tons of allowances for every ton of excess emissions.

    b) In accordance with RSA 125-O:7, for purposes of enforcement of the Multiple Pollutant Annual Budget Trading and Banking Program, in determining the number of days of violation, any excess emissions for the year shall create a presumption that each day in the year of 365 days, constitutes a day in violation unless PSNH Newington can demonstrate, through use of verifiable emissions data that a lesser number of days should be considered. In addition, each ton of excess emissions shall constitute a separate violation.

9. Conversion of Allowances to DERs or VERs

    a) Pursuant to Env-A 2904.01 (d), allowances shall not be considered offsets, although NOx allowances which are not used to satisfy the requirements of Env-A 2900, and which are not banked, may be converted to non-ozone season NOx DERs in accordance with Env-A 3100.

    b) Pursuant to Env-A 2904.02, *Conversion of Allowances to DERs or VERs*, if PSNH converts unused NOx allowances to NOx DERs in accordance with Env-A 2904.01(d) and the procedures for DER generation pursuant to Env-A 3103, or converts unused CO2 allowances to VERs in accordance with Env-A 3800, PSNH shall surrender those converted allowances as if they had been used for actual emissions.

10. Prohibition on Property Rights (Env-A 2904.04)

    a) Neither an allowance nor any future allocations, which are subject to modification by DES, shall constitute a security or other form of property.

    b) An allowance shall not be used prior to the year for which the allowance is allocated.

G. Discrete Emission Reduction Trading Program (Env-A 3100)

In accordance with Env-A 3100, NOx RACT Orders Nos. ARD-97-001 and ARD-98-001, and the Notices of Simultaneous Generation and Use of DERs originally submitted on April 10, 1998, and annually thereafter upon entry of the DERs into the registry by DES, PSNH Newington shall be allowed to bank DERs for PSNH Newington's own future use.

H. Monitoring/Testing Requirements

The Permittee is subject to the monitoring/testing requirements as contained in Table 9 below:

Table 9 - Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
1.	NT1	NOx Emissions	For NT1, PSNH shall install, certify, operate and maintain, a NOx-diluent continuous emission monitoring system (consisting of a NOx pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NOx concentration (in ppm) averaged on an hourly and 24-hour calendar day basis, O_2 or CO_2 concentration (in percent O_2 or CO_2) and NOx mass emission rate (in lb/MMBtu) averaged on an hourly, 24-hour calendar day, and annual basis for each unit. PSNH shall account for total NOx emissions, both NO and NO_2, either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2. PSNH shall measure and record NOx emissions in lb/hr averaged for one-hour and a 24-hour calendar day, and tons/consecutive 12-month period. PSNH shall calculate hourly, quarterly, and annual NOx emission rates (in lb/mmBtu) by combining the NOx concentration (in ppm), diluent concentration (in percent CO_2), and percent moisture according to the procedures in 40 CFR 75 Appendix F.	Continuously	Env-A 808.02 (a) (new) and 40 CFR 75.10(a)(2), 75.12, and Env-A 1211.03 (f)
2.	NT1	NOx Mass Emissions	For NT1, PSNH shall calculate hourly NOx mass emissions (in lbs) by multiplying the hourly NOx emission rate (in lbs/mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time. PSNH shall also calculate quarterly and cumulative year-to-date NOx mass emissions and (in tons) by summing the hourly NOx mass emissions according to the procedures in 40 CFR 75 Appendix F Section 8.	Hourly, quarterly, and cumulative year-to-date	40 CFR 75.71, and 75.72 and Env-A 3212 and Env-A 2910
3.	NT1	Ozone Season NOx Emission Rate and NOx Mass Emissions	PSNH, when required, shall determine the ozone season NOx emission rate (in lb/MMBtu) by dividing ozone season NOx mass emissions (in lbs) by heat input. PSNH shall also calculate cumulative NOx mass emissions for the ozone season (in tons) by	During the ozone season	Env-A 3212.01 and 40 CFR 75.75(b) and 75.72

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			summing the hourly NOx mass emissions according to the procedures in 40 CFR 75 Appendix F Section 8.		
4.	NT1, NTAB1, NTAB2	Sulfur Content of No. 2 Fuel Oil, No. 6 Fuel Oil, and Crude Oil	Fuel delivery tickets, other documentation from the fuel supplier or testing in accordance with appropriate ASTM test methods that certify the weight-percent of sulfur for each delivery of the No. 2 fuel oil, No. 6 fuel oil, and crude oil.	Each delivery of fuel	Env-A 806.02
5.	NT1	Sulfur Content of Natural Gas	Documentation from fuel supplier or conduct testing to determine the sulfur content of natural gas.	Upon request by DES and/or EPA	Env-A 809.02 (old) and Env-A 806.03 (new)
6.	NT1	SO_2 Emissions	PSNH shall install, certify, operate and maintain, an SO_2 CEMS automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm) averaged on an hourly and 24-hour calendar day basis, volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr averaged over one hour and each 24-hour calendar day, and tons/consecutive 12-month period and tons/calendar year) for each unit. PSNH shall demonstrate compliance with the State Acid Rain Program emission caps by using the CEMS data.	Continuously	Env-A 808.02 (a)(1) (new) and 40 CFR 75.10 (a)(1)
7.	NT1	CO_2 Emissions	PSNH shall install, certify, operate and maintain, a CO_2 CEMS automated data acquisition and handling system. PSNH shall measure and record CO_2 emissions in lb/hr averaged over each 24-hour calendar day and CO_2 concentration in percent averaged over each hour and over each 24-hour calendar day.	Continuously	40 CFR 75.10(a)(3), and State Permit to Operate No. PO-B-1030
8.	NT1	Stack volumetric flow rate	PSNH shall install, certify, operate and maintain, a CEMS automated data acquisition and handling system to measure and record stack volumetric flow rate (in kscfm) averaged over each hour and over each 24-hour calendar day.	Continuously	40 CFR 75, Env-A 2910.02
9.	NT1	Heat Input Rate	PSNH shall determine the heat input rate (in MMBtu/hr) to each unit for every hour or part of an hour any fuel is combusted following the procedures in 40 CFR 75 Appendix F.	Hourly	40 CFR 75.10(c) and Env-A 2910.02
10.	NT1	Net Electrical Output	PSNH shall monitor and/or calculate net electrical output.	Annually	Env-A 2910.02 and 40 CFR 75
11.	NT1	Ozone Season Heat Input	To determine the number of NOx allowances allocated, PSNH shall calculate ozone season	Hourly during ozone season	Env-A 3212.01 and

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			heat input by summing each unit's hourly heat input determined according to the procedures in 40 CFR 75 for all hours in which the unit operated during the ozone season		40 CFR 75.75(a)
12.	NT1	Operating Hours	PSNH shall maintain a log of the operating hours of the boiler.	Continuously	State Permit to Operate No. PO-B-1030
13.	NT1	Opacity	PSNH shall install, certify, operate and maintain, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) for each 6-minute period for each unit. As necessary, PSNH shall also use US EPA Method 9 to estimate opacity.	Continuously	40 CFR 75.10(a)(4) and Env-A 805.02 (old) and Env-A 808.02 (a) (new) and 807.02 (new)
14.	NT1	PM	PSNH shall conduct stack testing using US EPA Method 1-5 or 1-4 and 17 or other method approved by DES to determine the PM emissions. PSNH shall calculate and record the PM emission rate in lb/MMBtu on a 24-hour calendar day average and tons/consecutive 12-month period using stack test results and operating hours. PSNH may use other EPA-approved emission calculating methods to calculate PM emissions.	Testing at least every 5 years and/or upon request by DES and/or EPA	40 CFR 70.6 (a)(3)(i)(B)
15.	NT1	CO	PSNH shall install, certify, operate and maintain a CO CEMS automated data acquisition and handling system for measuring and recording CO concentration (in ppm) averaged on an hourly and 24-hour calendar day basis, volumetric gas flow (in scfh), and CO mass emissions (in lb/hr averaged over one hour and each 24-hour calendar day, and tons/consecutive 12-month period and tons/calendar year) for each unit. PSNH shall conduct RATA testing for CO annually to verify the data.	Continuously	40 CFR 70.6 (a)(3)(i)(B)
16.	NT1	Temperature of the flue gas at the outlet of the boiler	PSNH shall measure and record the temperature at the outlet of the boiler to determine the inlet temperature of the ESP using a thermocouple or other temperature-monitoring device.	Daily	40 CFR 70.6 (a)(3)(i)(B)
17.	NT1	Voltage of the TR Sets	PSNH shall measure and record the secondary voltage of the TR Sets using a voltage meter or equivalent monitoring device.	Daily	40 CFR 70.6 (a)(3)(i)(B)
18.	NT1	Current (in mAmps and KW)	PSNH shall measure and record the current (in mAmps and KW) using a current meter or equivalent monitoring device.	Daily	40 CFR 70.6 (a)(3)(i)(B)
19.	NT1	Spark rate per	PSNH shall measure and record the spark rate	Daily	40 CFR 70.6

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
		minute	per minute.		(a)(3)(i)(B)
20.	NTI	ESP fields out of service	PSNH shall monitor and record the ESP fields out of service.	Daily	40 CFR 70.6 (a)(3)(i)(B)
21.	NT1	Hours that Fly Ash Reinjection System Blowers is in Operation	PSNH shall maintain a log of the hours that the flyash reinjection system is operated.	Daily when flyash reinjection is in operation	40 CFR 70.6 (a)(3)(i)(B)
22.	NT1	Toner Usage	PSNH shall maintain records of the amount of toner combusted in the boiler in tons/day in order to demonstrate compliance with RSA 125-I and Env-A 1400.	Daily when combusting toner	40 CFR 70.6 (a)(3)(i)(B)
23.	NT1	SO_2, NOx, CO, PM, VOCs Emissions (tons/month and tons/ consecutive 12-month period)	Pursuant to the 40 CFR 52.21 (b)(21)(v) (dated July 1, 2002)[13], for an electric utility steam generating unit (other than a new unit or the replacement of an existing unit), actual SO2, NOx, CO, PM, VOC emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided PSNH maintains and submits to DES on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by DES, if it determines such a period to be more representative of normal source post-change operations. Pursuant to 40 CFR 52.21(b)(33) (dated July 1, 2002), representative actual annual emission means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after the physical change or change in the method of operation of a unit (or a different consecutive two-year period within 10 years after that change, where DES determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions,	Monthly	40 CFR 70.6 (a)(3)(i)(B) and 40 CFR 52.21 (b)(21) and (33), dated July 1, 2002

[13] See the letter dated March 13, 2002 from Kenneth A. Colburn, Director, Air Resources Division, DES to John M. McDonald, Vice President-Operations, PSNH concerning conditional new source review applicability determination concerning modifications at Newington Station.

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			DES shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under Title IV of the CAA; and exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole. In order to calculate annual emissions as required pursuant to 40 CFR 52.21 (dated July 1, 2002), PSNH shall monitor emissions of SO2, NOx, CO, PM, and VOCs for a period of 5 years or more beginning in 2002.		
24.	NT1	Fuel Flow Meters-Periodic Monitoring	PSNH shall inspect, when NT1 is in operation, maintain and/or repair the fuel oil flow meters as necessary to ascertain accurate operation in accordance with manufacturer's specifications. PSNH and/or the manufacturer shall calibrate or validate accurate operation of the fuel oil flow meters during planned major turbine-generator outages.	During planned major turbine-generator outages	40 CFR 70.6 (a)(3)(i)(B)
25.	NTAB1, NTAB2	NOx Emissions (for NOx RACT)	PSNH shall conduct stack testing using US EPA Method 7E to determine the NOx emissions. PSNH shall calculate and record the NOx emission rate in lb/MMBtu on a 24-hour calendar average, lb/hr on a 24-hour calendar average, and tons/consecutive 12-month period using fuel consumption measured with fuel meters and the stack test results and operating hours or other EPA-approved methods.	Every 3 years and upon written request by DES and/or EPA	Env-A 1211.12 (e) and 1211.20 and Env-A 803.02 and 40 CFR 70.6 (a)(3)(i)(B)
26.	NTAB1, NTAB2, NTEG1	Opacity	US EPA Method 9	As necessary as determined by PSNH, DES, and/or EPA	40 CFR 70.6 (a)(3)(i)(B)
27.	NTAB1, NTAB2	Sulfur Content of Propane	Fuel delivery tickets, other documentation from the fuel supplier or testing in accordance with appropriate ASTM test methods that certify the weight-percent of sulfur for each delivery of the propane.	Upon request by DES and/or EPA	Env-A 809.02 (old) and Env-A 806.03 (new)

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
28.	NTAB1, NTAB2	Operating hours	PSNH shall maintain a log of the operating hours of each device.	Monthly	State Permits to Operate Nos. PO-B-1031 and PO-B-1032 and 40 CFR 70.6 (a)(3)(i)(B)
29.	NTAB1, NTAB2	TSP	PSNH shall conduct stack testing using US EPA Method 1-5 or 1-4 and 17 to determine the TSP emission rate in lb/MMBtu. PSNH shall calculate and record the TSP emission rate in lb/MMBtu averaged over 24-hour calendar day using fuel consumption data and EPA approved emission factors or stack test results.	Stack testing upon request by DES and/or EPA	40 CFR 70.6 (a)(3)(i)(B)
30.	NTAB1, NTAB2	Fuel Consumption	PSNH shall measure and record the amount of fuel consumed using fuel flow meters and/or inventory purchase records.	Monthly	40 CFR 70.6 (a)(3)(i)(B)
31.	NTEG1	Operating hours	The emergency generator shall be equipped with a non-resettable hour meter.	Continuous	40 CFR 60.4209(a)
32.	NTAB1, NTAB2	Fuel Flow Meters-Periodic Monitoring	PSNH shall ensure that the fuel flow metering devices are calibrated according to manufacturer specifications or in a manner approved by the Division and at frequency consistent with manufacturer recommendations, but at a minimum every five calendar years.	According to manufacturer recommendation, but at a minimum every five calendar years	40 CFR 70.6 (a)(3)(i)(B)
33.	NT1	CEM Hourly Operating Requirements & Valid Hour of CEM Data	Pursuant to Env-A 808.01 and 808.03 and 40 CFR 75.10(d), the Permittee shall ensure that the CEMS and components meet the following hourly operating requirements: A) The Permittee shall ensure that each CEM is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval pursuant to 40 CFR 75.10(d) and pursuant to Env-A 808.03(c)(2) for each successive 5-minute period for gaseous emissions, unless a longer time period is approved in accordance with Env-A 809	Hourly	40 CFR 75.10(d) and Env-A 808.01(i) and 808.03

[14] The requirements of 40 CFR 75 are less stringent than Env-A 808. 40 CFR 75 requires hourly averages to be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. 40 CFR 75 allows an hourly average to be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to 40 CFR 75.21 and 40 CFR Appendix B or backups of data from the data acquisition and handling system, or recertification, pursuant to 40 CFR 75.20.

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			B) The Permittee shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, CO_2 mass emissions (if applicable), NOx concentration, and NOx emission rate data collected by the monitors to hourly averages. C) The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. D) Failure of an SO_2 or CO_2 pollutant concentration monitor, NOx concentration monitor, flow monitor, or NOx-diluent CEMS to acquire the minimum number of data points for calculation of an hourly average shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. E) For a NOx-diluent monitoring system, an hourly average NOx emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the NOx pollutant concentration monitor and the diluent monitor (CO_2). F) If a valid hour of data is not obtained, the Permittee shall estimate and record emissions or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data. G) Pursuant to Env-A 808.01(i), a valid hour of CEM emissions data means a minimum of 42 minutes of CEM readings taken in any calendar hour, during which the CEM is not in an out of control period and the facility is in operation.[14] H) Pursuant to Env-A 808.03(a), PSNH shall average and record the CEM data for gaseous emissions for each calendar hour. I) Pursuant to Env-A 808.03(c)(1), all CEM systems shall include a means to display instantaneous values of percent opacity and gaseous emission concentrations.		
34.	NT1	Stack Volumetric	PSNH shall meet the following requirements for the stack volumetric flow measuring	Continuously	Env-A 808.03(d)

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
		Flow Measuring Device	device: A) All differential pressure flow monitors shall have an automatic blow-back purge system installed and in wet conditions, shall have the capability for drainage of the sensing lines; and B) The stack flow monitoring system shall have the capability for manual calibration of the transducer while the system is on-line and for a zero check.		
35.	NT1	Minimum Measurement Capability Requirements for CEMS	The Permittee shall ensure that each CEMS is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in 40 CFR 75 Appendix A Sections 2.1.1.5, 2.1.2.5, and 2.1.4.3.	As specified by regulation	40 CFR 75.10(f)
36.	NT1	COMS Hourly Operating Requirements	Pursuant to 40 CFR 75.10(d), the Permittee shall ensure that each COMS and components meet the following hourly operating requirements: A) The Permittee shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing (and recording pursuant to Env-A 808.03(c)(2) unless a longer time period is approved in accordance with Env-A 809) for each successive 10-second period and one cycle of data recording for each successive 6-minute period. B) The Permittee shall reduce all opacity data to 6-minute averages calculated in accordance with the provisions of 40 CFR 51 Appendix M, except where the SIP or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement as shown below. C) Pursuant to Env-A 808.03(b)(1), PSNH shall average the opacity data to result in consecutive, non-overlapping 6-minute averages; and D) Pursuant to Env-A 808.03(b)(2), for units subject to the Env-A 2002.04(b) exemption, the total number of minutes in any 8-hour period where the opacity, as averaged in non-overlapping 6-minute periods, exceeds the applicable opacity standard.	Sampling for successive 10-second period and recording for successive 6-minute period	40 CFR 75.10(d) and Env-A 808.03(b) and (c)

Table 9 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			E) Pursuant to Env-A 808.03(c)(1), all CEM systems shall include a means to display instantaneous values of percent opacity and gaseous emission concentrations.		
37.	NT1	Specific Provisions for Monitoring SO_2 Emissions (SO_2 emissions and flow monitors)	A) Pursuant to 40 CFR 75.11, the Permittee shall meet the specific provisions for SO_2 CEMS and flow monitoring systems: PSNH shall meet the general operating requirements in 40 CFR 75.10 for an SO_2 continuous emission monitoring system and a flow monitoring system. B) During hours when the unit combusts only gaseous fuel, PSNH shall determine SO_2 emissions in accordance with 40 CFR 75.11 (e)(1), (e)(2) or (e)(3). C) Pursuant to 40 CFR 75.11 (e)(3), PSNH may determine SO_2 mass emissions using a certified SO_2 continuous monitoring system, in conjunction with a certified flow rate monitor system. However, when the unit burns any gaseous fuel that is very low sulfur fuel, as defined by 40 CFR 72.2, the SO_2 monitoring system shall be subject to the quality assurance provisions of 40 CFR 75.11 (e)(3).	As specified by regulations	40 CFR 75.11
38.	NT1	Specific Provisions for Monitoring NOx Emissions	A) Pursuant to 40 CFR 75.12, 75.71, and 75.72 and Env-A 3212, the Permittee shall meet the specific provisions for NOx-diluent CEMS, including the following: 1) Meet general operating requirements in 40 CFR 75.10 for a NOx continuous emission monitoring system. The diluent gas monitor in the NOx CEMS may measure either O_2 or CO_2 concentration in the flue gases. 2) Comply with NOx emission rate procedures contained in 40 CFR 75.12(c). B) The Permittee shall meet the annual and ozone season monitoring requirements according to 40 CFR 75.74, as applicable.	Continuously	40 CFR 75.12, 75.71, and 75.72 and Env-A 3212
39.	NT1	Specific Provisions for Monitoring CO_2	Pursuant to 40 CFR 75.13, the Permittee shall meet the specific provisions for CO_2 CEMS and flow monitoring systems.	Continuously	40 CFR 75.13

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
		Emissions			
40.	NT1	Specific Provisions for Monitoring Opacity	Pursuant to 40 CFR 75.14, the continuous opacity monitoring and recording system shall meet all the design, installation, equipment, and performance specifications of 40 CFR 60, Appendix B, Performance Specification 1, and all the operational and quality assurance requirements of Env-A 808 (new).	Continuously	40 CFR 75.14 and Env-A 808 (new)
41.	NT1	CEMS and COMS and Alternative Monitoring Certification	Pursuant to 40 CFR 75.20 and 40 CFR 75.70(d) and Env-A 3212.07 and Env-A 3212.10, the Permittee shall recertify the CEMS and COMS and alternative monitoring system whenever the Permittee makes a replacement, modification, or change to the systems or to the facility that could significantly affect the ability of the systems to accurately measure and record the requisite data. The Permittee must submit an application for recertification of the monitoring system to EPA and DES.	Whenever the Permittee makes a replacement, modification, or change to the systems or to the facility that could significantly affect the ability of the systems to accurately measure and record the requisite data	40 CFR 75.20, 40 CFR 75.70(d), and 40 CFR 75 Appendix E Section 1.2 and Env-A 3212.02, 3212.06, 3212.07, 3212.09, 3212.10 and 2910.04
42.	NT1	QA/QC Requirements	A) Pursuant to 40 CFR 75.21 (a)(1) and 40 CFR 75.70, the Permittee shall operate, maintain, and calibrate each CEMS according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B. B) Pursuant to 40 CFR 75.21 (a)(4), PSNH is not required to perform the daily and quarterly assessments of the SO_2 monitoring system on any day or any quarter when only gaseous fuel is combusted, if the SO_2 emissions are determined in accordance with 40 CFR 75.11 (e)(1) or (e)(2). However, if any daily calibration test or linearity test is failed when the unit is combusting gaseous fuel only, the SO_2 monitoring system is out-of-control. The length of the out-of-control period shall be determined according to 40 CFR 75 Appendix B Section 2.1.4 or 2.2.3. C) Pursuant to 40 CFR 75.21 (a)(5), PSNH shall perform the relative accuracy test audits of the SO_2 monitoring system only when the higher-sulfur fuel is combusted. D) Pursuant to 40 CFR 75.21(b), the Permittee shall operate, calibrate, and	As specified by regulation	40 CFR 75.21 and 75.70 and 75.74

Table 9. – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			maintain each COMS according to the procedures specified in the SIP, pursuant to 40 CFR 51 Appendix M. E) Pursuant to 40 CFR 75.21(c), the Permittee shall ensure that all calibration gases used to quality assure the operation of the instrumentation shall meet the definition in 40 CFR 72.2. F) Pursuant to 40 CFR 75.21(d) and (e), the Permittee shall comply with the provisions concerning consequences of audits and audit decertification. G) Within and prior to the ozone season, the Permittee shall meet the quality assurance requirements contained in 40 CFR 75.74, as applicable.		
43.	NT1	Reference Test Methods for Certification and Recertification of CEMS or COMS	The Permittee shall use the reference test methods listed in 40 CFR 75.22 and included in Appendix A to 40 CFR 60 to conduct monitoring system tests for certification or recertification of CEMS and excepted monitoring systems under 40 CFR 75 Appendix E and quality assurance and quality control procedures.	During certification or recertification tests	40 CFR 75.22
44.	NT1	Out-of-Control Periods	A) Pursuant to 40 CFR 75.21(e)(2), whenever a CEMS or COMS fails a quality assurance audit or any other audit, the system is out-of-control, and the Permittee shall follow the procedures for out-of-control periods in 40 CFR 75.24. B) Pursuant to Env-A 3212.10 and 2910.06, whenever any monitoring system fails to meet the quality assurance requirements of 40 CFR 75 Appendix B, PSNH shall substitute the data using the applicable procedures in 40 CFR 75, Subpart D, Appendix D or E. C) Pursuant to 75.24, if an out-of-control period occurs to a monitor or CEMS, the owner or operator shall take corrective action and repeat the tests applicable to the out of control parameter as described in 40 CFR 75 Appendix B. 1) For daily calibration error tests, an out of control period occurs when the calibration error of a pollutant concentration monitor exceeds 5.0% based upon the span value, the calibration error of a diluent gas	As specified by regulation	40 CFR 75.21(e)(2) and 75.24 and Env-A 3212.10 and 2910.06 and 808.01(g)

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			monitor exceeds 1.0% O_2 or CO_2, or the calibration error of a flow monitor exceeds 6.0% based upon the span value, which is twice the applicable specification in 40 CFR 75 Appendix A. 2) For quarterly linearity checks, an out of control period occurs when the error in linearity at any of the three gas concentrations (low, mid-range, and high) exceeds the applicable specification in 40 CFR 75 Appendix A. 3) For relative accuracy test audits (RATAs), cylinder gas audit (CGAs), and relative accuracy audits (RAAs), an out of control period occurs when the sampling is completed and the CEMS fails the accuracy criteria until successful completion of the same audit after corrective action has occurred. D) Pursuant to Env-A 3212.10, whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement pursuant to Env-A 800 or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the department shall issue a notice of disapproval of the certification status of such system or component. E) For the purposes of this section, an audit shall be either a field audit or an audit of any information submitted to the department or the administrator. F) The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the disapproval of certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests		

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			in accordance with Env-A 3212.07(t). G) The owner or operator shall follow the initial certification or recertification procedures for each disapproved system.		
45.	NT1	Out of Control Periods for Opacity	Out of control period for a CEMS measuring opacity is as follows: A) The time period beginning with the completion of the daily calibration drift check where the CD exceeds 2% opacity for 5 consecutive days, and ending with the CD check after corrective action has occurred that results in the performance specification drift limits being met; B) The time period beginning with the completion of a daily CD check preceding the daily CD check that results in the CD being greater than 5% opacity and ending with the CD check after corrective action has occurred that results in the performance specification drift limits being met; or C) The time period beginning with the completion of a quarterly opacity audit where the CEMS fails the calibration error test as specified in 40 CFR 60, Appendix B, Specification 1 and ending with successful completion of the same audit where the CEMS passes the calibration error test established after corrective action has occurred.	As specified by regulation	Env-A 808.01(g)(2)
46.	NT1	Data Availability and Missing Data Substitution Procedures	A) The Permittee shall follow the procedures in 40 CFR 75.30 through 75.37, 75.70(f), 75.74, and 40 CFR 75 Appendix E when a valid, quality-assured hour of data is not measured or recorded. B) Pursuant to Env-A 808.02(c)(2), PSNH shall comply with the minimum percentage data availablity requirements pursuant to Env-A 808.10(a)-(d) to meet the requirements of Env-A 3200, *NOx Budget Program.* C) Pursuant to Env-A 808.10, if PSNH cannot meet the percentage data availability requirements, PSNH shall also follow the provisions of Env-A 808.10(e) – (g). D) Pursuant to 40 CFR 75.24(e), if COMS is out of control, PSNH shall follow the data availability requirements of Env-A 808.10.	As specified by regulation	40 CFR 75.30 through 75.37 and 75.50(f) and 75.24(e) and 75.74 and 40 CFR 75 Appendix E Section 2.5 and Env-A 808.10 and 808.02(c)(2)

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
47.	NT1	General CEM Requirements	A) Pursuant to 40 CFR 75.5 (b), the Permittee must operate NT1 in compliance with the requirements of 40 CFR 75.2 through 75.75 and 40 CFR 75 Appendices A through G. B) Pursuant to 40 CFR 75.5 (d), the Permittee shall account for all emissions of SO_2, NOx, and CO_2 in accordance with 40 CFR 75.10 through 75.19. C) Pursuant to 40 CFR 75.5 (e), the Permittee shall not disrupt the continuous emission monitoring system or other approved emission monitoring method, and thereby not monitor or record SO_2, NOx, and CO_2, except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and 40 CFR 75 Appendix B. D) The CEMS shall meet the most stringent requirements of 40 CFR 75 and Env-A 808 (new).	Continuously	40 CFR 75.5 and Env-A 808 (new)
48.	NT1	CEMS Performance and Audit Requirements	The Permittee shall ensure that each CEMS meets the following requirements: A) Each CEMS meets equipment, installation, and performance specifications in 40 CFR 75 Appendix A; B) Each CEMS is maintained according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B; and C) Each CEMS shall record SO_2 and NOx emissions in the appropriate units of measurement. D) PSNH shall comply with the most stringent CEM audit requirements contained in 40 CFR 75 and Env-A 808.07, *General Audit Requirements*, Env-A 808.08, *Audit Requirements for Gaseous CEM Systems*, and Env-A 808.09, *Audit Requirements for Opacity CEM Systems*.	As specified by regulation	40 CFR 75.10(b) and Env-A 808.07, 808.08, and 808.09 and 40 CFR 75 Appendices A and B
49.	NT1	NOx Mass Emissions – General Provisions	Pursuant to Env-A 3200, *NOx Budget Program,* PSNH shall comply with the provisions of 40 CFR 75 Subparts A, C, D, E, F, and G and Appendices A through G applicable to NOx concentration, flow rate, NOx emission rate and heat input, as set forth and referenced in Subpart H.	As specified by regulation	Env-3212.01 and 40 CFR 75.70(a)
50.	NT1	NOx Mass	PSNH is prohibited from the following:	Continuously	40 CFR

Table 9 – Monitoring/Testing Requirements					
Item No.	Device	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
		Emissions Provisions-Prohibitions	A) Using alternative monitoring system, reference method, or any other alternative for the required CEMS without approval through petition process in 40 CFR 75.70(h). B) Discharging or allowing discharge of NOx emissions without accounting for all emissions in accordance with the provisions of Subpart H, except as provided in 40 CFR 75.74. C) Disrupting the CEMS or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass emissions, except for periods of re-certification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of 40 CFR 75 Subpart H applicable to the monitoring systems under 40 CFR 75.71, except as provided in 40 CFR 75.74. D) Retiring or permanently discontinuing the use of the CEMS, or any other approved emission monitoring system except under one of the following circumstances: 1) During a period that the unit is covered by a retired unit exemption that is in effect under the State or federal NOx mass emission reduction program that adopts the requirements of Subpart H; 2) The owner or operator is monitoring NOx emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of 40 CFR 75.70(d); or 3) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with 40 CFR 75.61.		75.70(c)
51.	NT1	NOx Mass Emissions – Petitions for Alternatives	PSNH may submit a petition to DES and EPA requesting an alternative to any requirement of 40 CFR 75 Subpart H. Such a petition shall meet the requirements of 40 CFR 75.66 and any additional requirements established by Env-A 3200 or other applicable state or Federal NOx mass emission reduction programs that adopt the requirements of 40	Not applicable	40 CFR 75.70(h) and 40 CFR 75 Subpart E and 40 CFR 75 Appendix E and Env-A 3212.09

Table 9 – Monitoring/Testing Requirements					
Item No.	**Device**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			CFR 75 Subpart H.		
52.	NT1	NOx Mass Emissions – NOx Emission Rate and Heat Input –Oil/Gas Non-Peaking Units	For an affected unit that qualifies as a non-peaking gas-fired or non-peaking oil-fired unit, PSNH shall either: A) Meet the requirements of 40 CFR 75.71(a) and (b); or B) Meet the general operating requirements in 40 CFR 75.10 for NOx diluent continuous emission monitoring system, except as provided in accordance with 40 CFR 75 Subpart E, and use the procedures specified in 40 CFR 75 Appendix D for determining hourly heat input. The heat input apportionment provisions in Section 2.1.2 of 40 CFR 75 Appendix D shall not be used to meet the NOx mass reporting provisions of 40 CFR 75 Subpart H.	As specified by regulation	40 CFR 75.71(c)
53.	NT1	NOx Mass Emissions – Annual Monitoring	PSNH shall meet the requirements of 40 CFR 75 Subpart H during the entire calendar year.	During the calendar year	40 CFR 75.74(a) and (b)
54.	NT1	Valid Averaging Periods for Gaseous and Opacity CEMS	The number of hours of valid CEM and COM data required for determining a valid averaging period for the different emission standard periods shall be: A) For a 3-hour emission standard period, 2 hours of valid data; B) For a 4-hour emission standard period, 3 hours of valid data; C) For an 8-hour emission standard period, 6 hours of valid data; D) For a 12-hour emission standard period, 9 hours of valid data, and E) For a 24-hour emission standard period, 18 hours of valid data.	As specified by regulation	Env-A 808.14 and 805.09 (old)
55.	Facility wide	Inventories of Regulated Substances	PSNH shall monitor the quantity of regulated substances to ensure that facility is in compliance with the requirements of 40 CFR 68.	Continuously	40 CFR 68 and 1990 CAA Section 112(r)(1)

I. Recordkeeping Requirements

The Permittee is subject to the Recordkeeping requirements as contained in Table 10 below:

Table 10 – Applicable Recordkeeping Requirements[15]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
1.	Liquid Fuel Utilization Records: The Permittee shall maintain the following monthly records, or records for an alternative period as approved by DES in accordance with Env-A 912, of the liquid fuel characteristics and utilization: A) Fuel consumption (monthly and 12-month rolling average); B) Fuel type; C) Viscosity (based on generally accepted values); D) Sulfur content as percent sulfur by weight of fuel; E) BTU content per gallon of fuel; and F) Hours of operation of each fuel combustion device while operating with each type of liquid fuel, so the distribution of fuel among each combustion device can be estimated.	Monthly or an alternative period as approved by DES in accordance with Env-A 912 and for fuel consumption, monthly and 12-month rolling average	NT1, NTAB1, NTAB2, NTEG1	Env-A 901.03(a)(1) and (c) (old) and Env-A 903.03(a)(3) and (b) (new)
2.	Gaseous Fuel Utilization Records: The Permittee shall maintain the following monthly records, or records for an alternative period as approved by DES in accordance with Env-A 912, of the fuel characteristics and utilization: A) Fuel consumption (monthly and 12-month rolling average); B) Fuel type; C) Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel (as tested upon request by DES and/or EPA); D) Hours of operation of each fuel combustion device while operating with each type of gaseous fuel, so the distribution of fuel among each combustion device can be estimated.	Monthly or an alternative period as approved by DES in accordance with Env-A 912 and for fuel consumption, monthly and 12-month rolling average	NT1, NTAB1, NTAB2	Env-A 903.03(a)(4) (new)
3.	Monitoring Plan and QA/QC Plan: A) The Permittee shall prepare and maintain a monitoring plan for the CEMS and COMS,	Whenever a change occurs that could affect monitoring	NT1	40 CFR 75.53 (a), (b), (e), and (f) and Env-A 808.06 and

[15] On April 23, 1999 DES promulgated new Env-A 900 rules to streamline the recordkeeping and reporting requirement sections of the New Hampshire Code of Administrative Rules. Until such time that the new Env-A 900 rules are approved and adopted into the State Implementation Plan (SIP) by EPA, all Title V permits will be incorporating the old Env-A 900 rules (which became effective on November 11, 1992), unless the new Env-A 900 rules are more stringent. These recordkeeping and reporting requirements shall fall under the Permit Shield provisions as contained in Section XIII of this permit.

Table 10 – Applicable Recordkeeping Requirements[15]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	which contains sufficient information to demonstrate that all unit SO_2 emissions, NOx emissions, CO_2 emissions and opacity are monitored and reported. B) The Permitte shall prepare and maintain monitoring plans for other approved monitoring methods, which contain sufficient information to demonstrate that all unit NOx emissions are monitored and reported. C) The Permittee shall update the monitoring plan whenever the Permittee makes a replacement, modification or change that could affect the CEMS or COMS or other approved monitoring method. D) The Permittee shall review the QA/QC plan and all data generated by its implementation at least once each year. E) The Permittee shall revise or update the QA/QC plan, as necessary, based on the results of the annual review by conducting the following: 1) Documenting any changes made to the CEM or the monitoring method or changes to any information provided in the monitoring plan; 2) Including a schedule of, and describing, all maintenance activities that are required by the CEM manufacturer or that might have an effect on the operation of the system; 3) Describing how the audits and testing required by this part will be performed; and 4) Including examples of the reports that will be used to document the audits and tests required by this part; 5) Make the revised QA/QC plan available for on-site review by the division at any time; and 6) Within 30 days of completion of the annual QA/QC plan review, certify in writing that the owner or operator will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reasons for each change. F) The QA/QC plan shall be considered an update to the CEM monitoring plan	method or annually, whichever is more frequent		3212.13 and 2910.09

Table 10 – Applicable Recordkeeping Requirements				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	required by Env-A 808.04. G) Pursuant to Env-A 3212.13(a) and Env-A 2910.09, the unit subject to acid rain emission limitations (NT1) shall comply with the requirements of 40 CFR 75.62, except the monitoring plan shall also include all of the information required by 40 CFR 75, Subpart H.			
4.	<u>CEM, COMS and Other Approved Monitoring Methods Recordkeeping Requirements:</u> A) The Permittee shall record and maintain the information required pursuant to 40 CFR 75.57, 75.58, 75.59, and 75.73(b), which includes the certification, quality assurance, and quality control records. B) The Permittee shall record and maintain CEMS and COMS records according to the most stringent requirements of Env-A 808 and 40 CFR 75.	As specified by regulation	NT1	40 CFR 75.57, 75.58,75.59, and 75.73 and Env-A 3212 and Env-A 903.04 (a) (new) and Env-A 800 and 40 CFR 75
5.	<u>General NOx Recordkeeping Requirements:</u> The Permittee shall record and maintain the following information for fuel burning devices: A) Facility information, including the following: 1) Source name; 2) Source identification; 3) Physical address; and 4) Mailing address. B) Identification of fuel burning devices; C) Operating schedule for each fuel burning device identified in Condition B) above: 1) Days per calendar week during the normal operating schedule; 2) Hours per day during the normal operating schedule and for a typical ozone season day; and 3) Hours per year during the normal operating schedule. D) Type and amount of fuel burned for each fuel-burning device during normal operating conditions and for a typical ozone season day, if different from normal operating conditions, on an hourly basis in mmBtu/hr. E) Theoretical potential NOx emissions for the calculation year for each fuel burning device: 1) Annual emissions, in tons per year; and 2) Typical ozone season day emissions, in	Annually and as applicable	NT1, NTAB1, NTAB2, NTEG1	Env-A 901.08 (c) (1)–(5) (old) and Env-A 905.02 (new)

Table 10 – Applicable Recordkeeping Requirements[15]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	pounds per day. F) Actual NOx emissions for each fuel burning device: 1) Annual emissions, in tons per year; and 2) Typical ozone season day emissions, in pounds per day. G) Emission factors and the origin of the emission factors used to calculate the NOx emissions.			
6.	Sulfur Analysis Records for Fuel Oil: PSNH shall maintain delivery tickets from each fuel oil supplier for each shipment of fuel oil received. The delivery tickets shall be in a form suitable for inspection and available to the DES and/or EPA upon request. Each delivery ticket shall indicate the following: A) The name of the fuel supplier; B) The address of the fuel supplier; C) The telephone number of the fuel supplier; D) The type of fuel delivered; E) The quantity of fuel oil delivered; F) The date of delivery; and G) The maximum percent sulfur by weight of the fuel oil delivered. If the delivery tickets do not contain sulfur content of fuel delivered, the Permittee shall provide other documentation from the fuel supplier with the above information or perform testing in accordance with appropriate ASTM test methods to determine compliance with the sulfur content limitation provisions in Env-A 1604 for liquid fuels.	For each delivery of fuel oil	NT1, NTAB1, NTAB2, NTEG1	Env-A 806.05 (new) and 40 CFR 70.6(a)(3)
7.	Delivery Ticket for Propane: PSNH shall maintain delivery tickets from each propane supplier for each shipment of propane received. The delivery tickets shall be in a form suitable for inspection and available to the DES and/or EPA upon request. Each delivery ticket shall indicate the following: A) The name of the fuel supplier; B) The address of the fuel supplier; C) The telephone number of the fuel supplier; D) The type of fuel delivered; E) The quantity of propane delivered; F) The date of delivery.	For each delivery of propane	NTAB1, NTAB2	Env-A 806.05 (new) and 40 CFR 70.6(a)(3)
8.	Natural Gas Utilization Records: PSNH shall maintain billing tickets for each natural gas supplier. The billing tickets shall be in a form	Monthly	NT1	State Permit to Operate No. PO-B-1030

Table 40 – Applicable Recordkeeping Requirements[15]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	suitable for inspection and available to the DES and/or EPA upon request. Each billing ticket shall indicate the following: A) The name of the fuel supplier; B) The address of the fuel supplier; C) The telephone number of the fuel supplier; and D) The quantity of natural gas used.			
9.	Emergency Generator Operating Records: PSNH shall record and maintain monthly and annual records of the operating hours of the emergency generator.	Monthly	NTEG1	TP-B-0536
10.	Auxiliary Boiler Operating Records: PSNH shall record and maintain monthly and consecutive 12-month records of the operating hours of each auxiliary boiler	Monthly	NTAB1, NTAB2	State Permit to Operate No. PO-B-1031 and PO-B-1032
11.	Multipollutant Budget and Trading Program Recordingkeeping Requirements: PSNH shall comply with the recordkeeping requirements of the multipollutant budget and trading program.	As required by RSA 125-O and Env-A 2900	NT1	Env-A 2900
12.	Certificate of Representation: The Permittee shall complete and retain a certificate of representation for a designated representative or an alternate designated representative including the elements pursuant to 40 CFR 72.24, *Certificate of representation.*	Maintain at the facility at all times	NT1	40 CFR 72.24
13.	Record Retention: The Permittee shall retain the records required by this permit on file for a minimum of 5 years except the certificate of representation for the designated representatives shall be kept beyond the 5-year period.[16]	Retain for a minimum of 5 years or as specified	Facility wide	Env-A 902.01 (a) (new), Env-A 3213, 40 CFR 70.6 (a)(3)(ii)(B), and 40 CFR 72.9 (f)
14.	Regulated Toxic Air Pollutant Records: The Permittee shall maintain records in accordance with the applicable method used to demonstrate compliance pursuant to Env-A 1405.	Maintain at facility at all times	All devices subject to RSA 125-I and Env-A 1400	Env-A 902.01 (c) (new) State Enforceable Only
15.	Representative Actual Annual Emissions Test Recordkeeping Requirements: PSNH shall maintain records of SO_2, NOx, CO, PM, and VOCs emissions in tons/month and tons per consecutive 12-month period for NT1.	Monthly	NT1	40 CFR 52.21(b)(21) and (33), dated July 1, 2002 and 40 CFR 70.6(a)(3)(ii) and Env-A 906
16.	Monitoring Records: The Permittee shall maintain records of monitoring results as specified in Table 9 of this Permit including the	Maintain as required in Table 9	As specified for each monitoring record	40 CFR 70.6(a)(3)(ii)

[16] Note that record retention for five years is more stringent than the three year record retention required in some sections of 40 CFR 75.

Table 10 – Applicable Recordkeeping Requirements[15]				
Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
	following: A) Visible emission/opacity test results for NT1, NTAB1, NTAB2, and NTEG; B) NOx, SO_2, CO_2, continuous emissions monitoring data for NT1; C) Stack volumetric flow rate for NT1; D) Heat input rate for NT1; E) PM emissions (in lb/MMBtu over a 24-hour calendar day, tons per 12-month period) for NT1, NTAB1, and NTAB2; F) Toner usage in tons/day for NT1; G) Voltage of the transformer rectifier sets (TR Sets) for NT1-PC1; H) Temperature of flue gas at the outlet of the boiler (in degrees F) for NT-PC1; I) Current to ESP for NT1-PC1; J) Spark Rate in ESP for NT1-PC1; K) Fields out of service in ESP for NT1-PC1; L) Hours of operation of the flyash reinjection system for NT1; M) NOx, SO_2, CO, and VOC emissions for the auxiliary boilers for NTAB1 and NTAB2; N) Net electrical output (MWh) for NT1; O) Flow metering calibrations for NT1, NTAB1, and NTAB2; and P) Quantities of regulated substances above the thresholds established by EPA under 40 CFR 68.130 facilitywide.			
17.	Operating Scenario Records: PSNH shall maintain a record of the scenarios under which it is operating. PSNH shall specify whether operation is under normal conditions or an alternative operating scenario listed in Section VII. PSNH shall specify which alternative operating scenario is in use.	Whenever operation method changes from normal operation to a specific alternative operating scenario	Facility wide	40 CFR 70.6 (a)(9)
18.	*NSPS Recordkeeping Requirements for Internal Combustion Engines* Maintain documentation from the engine manufacturer certifying that the engine complies with the applicable emissions standards stated in 40 CFR 60 Subpart IIII.	Maintain Up-to-Date Data	NTEG1	40 CFR 60.4211 (NSPS Subpart IIII)

J. Reporting Requirements

The Permittee is subject to the federally enforceable reporting requirements identified in Table 11 below:

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
1.	NOx Reporting Requirements: The Permittee shall submit reports of the NOx records kept pursuant to the Section VIII. I. Table 9, Applicable Recordkeeping Requirements.	Annually (no later than April 15th of the following year)	NT1, NTAB1, NTAB2, NTEG1	Env-A 901.09 (old) and Env-A 909.03 (new)
2.	State Acid Deposition Control Program Reporting Requirements: The Permittee shall submit an annual report of the fuel utilization information pursuant to Env-A 903.03 and Section VIII. I. Table 10, Applicable Recordkeeping Requirements.	Annually (no later than April 15th of the following year)	NT1	Env-A 907.02 (new)
3.	CEMS Recertification Notifications and Reports: A) The Permittee shall notify EPA and DES by telephone or in writing and not later than 21 days prior to the first scheduled day of full recertification testing and at least 7 calendar days prior to the first scheduled day of partial recertification testing (when all of the tests are not required). In emergency situations when equipment fails with lost data, the Permittee may provide notice within 2 business days following the date when testing is scheduled. If the testing is rescheduled, the Permittee may notify DES and EPA by telephone or other means within 2 business days prior to the scheduled test date or the revised test date, whichever is earlier. B) Within 45 calendar days after completing all recertification tests, the Permittee shall submit to EPA and DES the electronic and hardcopy information contained in 40 CFR 75.63. C) Pursuant to Env-A 3212.14 and Env-A 2910.10, PSNH shall submit an application to DES within 45 days after completing all initial certification or recertification tests including the information required under 40 CFR 75, Subpart H. D) Pursuant to Env-A 2910.07, PSNH shall also submit written notification required pursuant to 40 CFR 75.61 to the ATS administrator.	7 days prior to partial recertification, 21 days prior to full recertification, and 45 days after all recertification tests	NT1	40 CFR 75.61 (a)(1), 75.70, 75.63, and 75.73(d) and Env-A 3212 and 2910
4.	Relative Accuracy Test Audit (RATA)	21 calendar days	NT1	40 CFR 75.61

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	Notification and Reports: A) The Permittee shall submit written notice to EPA and DES no later than 21 calendar days prior to the first scheduled day of testing.[17] If the testing is rescheduled, the Permittee may notify DES and EPA by telephone or other means no later than 24-hours in advance of the new testing date. DES shall require rescheduling of the RATA if staff necessary to observe the RATA are not available. B) If requested, the Permittee shall submit the quality assurance RATA reports to EPA and DES by the later of 45 days after completing a quality assurance RATA or 15 days of receiving the request. C) Pursuant to Env-A 808.07(b), PSNH shall submit to DES a written report summarizing the testing within 30 days of the completion of the test. D) Pursuant to Env-A 2910.07, PSNH shall also submit written notification required pursuant to 40 CFR 75.61 to the ATS administrator.	prior to RATA		(a)(5) and 75.73(d) and Env-A 3212.11 and 2910 and 808.05 and 808.07(c) and (d)
5.	Performance Specification Testing Reports: A) DES shall be notified of the date or dates of the performance specification testing at least 30 days prior to the scheduled dates. B) PSNH shall submit to DES a written report summarizing the testing within 30 days of the completion of the test.	30-day notice to DES prior to test; test report to DES 30 days after the test	NT1	Env-A 808.05
6.	General Audit Notification Requirements: PSNH shall notify DES at least 2 weeks prior to any planned audit or test procedure except for RATAs, where PSNH shall provide at least 30 days notice prior to the performance of the RATA.	2 weeks prior to any planned audit or test procedure and at least 30 days prior to the RATA.	NT1	Env-A 808.07(c) and (e)
7.	Monitoring and QA/QC Plan Submittals: The Permittee shall submit to EPA and DES a complete, electronic, up-to-date monitoring plan at the time of recertification application submission and in each electronic quarterly report, and whenever an update of the electronic monitoring plan information is required.	In the recertification application, in each electronic quarterly report, and whenever an update of the electronic monitoring plan information is required	NT1	40 CFR 75.62 and 75.73(d) and (e) and Env-A 808.04, 808.06, 3212 and 2910
8.	Quarterly Reports: A) The Permittee shall submit to DES and EPA in	30 calendar days after the end of the	NT1	40 CFR 75.64, 40 CFR 75.73(f), 40

[17] Note that pursuant to Env-A 808.07, PSNH shall notify DES at least 30 days prior to the performance of the RATA. This requirement is less stringent than the requirement of 40 CFR 75.

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	electronic format or other format as approved by DES and/or EPA 30 calendar days after the end of the calendar quarter the information contained in 40 CFR 75.64(a), 40 CFR 75.73(f), 40 CFR 75.74, Env-A 2912, Env-A 3212, Env-A 3214, Env-A 808.11(new), and Env-A 808.13 (new) and the following information: 1) Written report of opacity, SO_2, NOx, and CO_2 emissions as calculated by the CEMS. 2) The 24-hour averages of the following shall be reported, whether or not an excess emission has occurred: a. SO_2 lb/MMBtu, SO_2 ppm, and SO_2 lb/hr; b. NOx lb/MMBtu, NOx ppm, and NOx lb/hr; c. Percent CO_2 and CO_2 lb/hr as measured by continuous monitor/recorder; d. Stack volumetric flowrate (in kscfm); e. Load (in MW); f. Steam flow (in klbs/hr); g. Heat input (MMBtu/hr); and h. Opacity (in percent). 3) Excess emission data recorded by the CEM system, including the following: a. The date and time of the beginning and ending of each of excess emissions; b. The magnitude of each excess emission; c. The specific cause of the excess emission; and d. The corrective action taken. 4) If no excess emissions have occurred, a statement to that effect; 5) For gaseous emission monitoring systems, the daily averages of the measurements made and emissions rates calculated. 6) A statement as to whether the CEM system was inoperative, repaired, or adjusted during the reporting period; 7) If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: a. The date and time of the beginning and ending of each period when the	calendar quarter		CFR 75.57(f), 40 CFR 75.74, Env-A 2910, Env-A 2911, Env-A 3212, Env-A 3214, Env-A 808.11(new), Env-A 808.13 (new), and State Permit to Operate No. PO-B-1030

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	CEM was inoperative; b. The reason why the CEM was not operating; c. The corrective action taken; and d. The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or pollutant analyzer in the CEM system; 8) The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating; 9) When calibration gas is used, the following information: a. The calibration gas concentration; b. If a gas bottle was changed during the quarter: i) The date of the calibration gas bottle change; ii) The gas bottle concentration before the change; and iii) The gas bottle concentration after the change; and c. The expiration date for all calibration gas bottles used. 10) Excess emissions of SO_2 shall be defined as an annual SO_2 emission, which exceeds the state acid rain emission limitation, as calculated from CEM data. B) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports represent current operating conditions. C) The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. D) The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of 40 CFR 75, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method.			

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	E) For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of 40 CFR 75.34(a)(1), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NOx emissions, pursuant to 40 CFR 75.34. F) For a unit that is reporting on a control period basis, the designated representative shall also include a certification that the NOx emission rate and NOx concentration values substituted for missing data under 40 CFR 75 Subpart D are calculated using only values from a control period and do not systematically underestimate NOx emissions. G) Pursuant to Env-A 3212.15(e) and Env-A 2910.11(a)(3), the quarterly reports shall be submitted in the manner specified in 40 CFR 75, Subpart H and 40 CFR 75.64. H) Pursuant to Env-A 3212.15(f) and Env-A 2910.11(a)(4), for NT1 the quarterly reports shall include all of the data and information required in 40 CFR Subpart H and 40 CFR Subpart G. I) Pursuant to Env-A 3214.01 and Env-A 2911.01, PSNH shall also submit emissions and operations information in electronic format as part of the quarterly reports. J) Pursuant to Env-A 3214.02, PSNH shall also submit to the NETS administrator in the quarterly reports, NOx emissions in lb/hr for every hour during the control period and cumulative quarterly and seasonal NOx emission data in pounds. K) Pursuant to Env-A 2911.02, PSNH shall also submit to the ETS administrator in the quarterly reports, SO_2, NOx and CO_2 emissions in lb/hr for every hour during the year and cumulative quarterly and annual SO_2, NOx and CO_2 emissions data in pounds.			
9.	<u>Offset Plans for Excess SO_2 Emissions</u>: The Permittee shall submit an offset plan no later than 60 days after the end of any calendar year during which a unit has excess SO_2 emissions. The offset plan shall contain the information pursuant to 40	60 days after the end of any calendar year	NT1	40 CFR 77.3

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	CFR 77.3.			
10.	Quarterly Audit Reports: Pursuant to Env-A 808.07 (new), the Permittee shall submit to DES, a written summary report of the results of all required audits that were performed in that quarter, in accordance with the following: A) For gaseous CEM audits, the report format shall conform to that presented in 40 CFR 60, Appendix F, Procedure 1, Section 7; and B) For opacity CEM audits, the report format shall conform to that presented in EPA-600/8-87-025, April 1992, "Technical Assistance Document: Performance Audit Procedures for Opacity Monitors."	Quarterly, no later than 30 calendar days after the end of the quarter for which reporting is required	NT1	Env-A 808.07 (new)
11.	Quarterly Fuel Data Reports: The Permittee shall submit the fuel data listed in Table 10 above summarized on a monthly basis and for the previous 3 quarters in addition to the current reporting quarter. The Permittee shall submit monthly fuel usage information, including fuel type and the sulfur content by device.	Quarterly, no later than 30 calendar days after the end of the quarter for which reporting is required	NT1, NTAB1, NTAB2	Env-A 910 and State Permits to Operate Nos. PO-B-1030, PO-B-1031, and PO-B-1032
12.	Annual Fuel Data Reports: The Permittee shall submit quarterly fuel usage information for the emergency generator on a calendar year basis.	Annually (no later than April 15th of the following year)	NTEG1	Env-A 910
13.	Performance Test Reports: The Permittee shall submit a report to DES documenting the results of the compliance stack emission test. The compliance stack emission test report shall contain the following information: A) All the information required for the pre-test protocol as described in Env-A 802.04; B) All test data; C) All calibration data; D) Process data agreed by DES and the Permittee to be collected; E) All test results; F) A description of any discrepancies or problems that occurred during testing or sample analysis; G) An explanation of how discrepancies or problems were treated and their effect on the final results; and H) A list and description of all equations used in the test report, including sample calculations for each equation used.	No later than 60 days after a performance test	Facility wide	Env-A 802.11 (new)
14.	Net Electrical Output Reporting – The Permittee shall report monthly data[18] of the net electrical	Annually (no later than April 15th of	NT1	Env-A 2906.05(g) and

[18] Copies of the Forms EIA-906 and EIA-920 are sufficient.

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	output of each affected source for the calendar year and the ozone season to DES.	the following year)		3207.04(k)
15.	Regulated Toxic Air Pollutant Reports: The Permittee shall report actual emissions speciated by individual regulated toxic air pollutants, including a breakdown of VOC emission compounds.	Annually (no later than April 15th of the following year)	Facility wide	Env-A 907.01 (new) State Enforceable Only
16.	Representative Actual Annual Emissions Test Emissions Reporting Requirements: PSNH shall submit to DES annually SO_2, NOx, CO, PM, and VOCs emissions in tons/month and consecutive 12-month period for NT1.	Annually (no later than April 15th of the following year)	NT1	40 CFR 52.21(b)(21) and (33), dated July 1, 2002 and Env-A 910 (new)
17.	Semi-Annual Permit Deviation/Monitoring Reports: The Permittee shall submit a permit deviation/monitoring report of the data specified in Table 9 of this Permit every 6 months. All required reports must be certified by a responsible official consistent with 40 CFR 70.5(d). The report shall contain a summary of the following information, unless this information was provided (or will be provided) to DES pursuant to another requirement: A) Visible emission/opacity test results for NT1, NTAB1, NTAB2, and NTEG; B) Summary showing monthly average sulfur content of the liquid and gaseous fuels from testing and/or delivery ticket and/or other documentation certifications for liquid and gaseous fuel sulfur content for NT1, NTAB1, and NTAB2; C) NOx, SO_2, CO_2, continuous emissions monitoring data for NT1; D) PM emissions (in lb/MMBtu over a 24-hour calendar day, tons per 12-month period) for NT1, NTAB1, and NTAB2; E) Toner usage in tons/day and an indication of the combustion of any new toners for NT1; F) Hours of operation without the flyash reinjection system for NT1; G) NOx, SO_2, CO, and VOC emissions for the auxiliary boilers (NTAB1, NTAB2) and emergency generator (NTEG); H) Net electrical output (MWh) for NT1; I) Operating hours for the emergency generator (NTEG); and J) All instances of deviations from Permit requirements.	Semiannually (by July 31st and January 31st of each calendar year)	Facility wide	40 CFR 70.6(a)(3)(iii)(A) and Env-A 911.05
18.	Notification of Removal of Overfire Air: PSNH shall notify DES in writing within 30 calendar	Within 30 calendar days of removal	NT1	Env-A 910 (new)

Table 11 – Applicable Reporting Requirements				
Item No.	Reporting Requirement	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
	days of removing the overfire air capabilities.			
19.	Prompt Reporting of Permit Deviations: The Permittee shall promptly report deviations from permit requirements by phone, fax or e-mail in accordance with Section XXVIII of this permit and Env-A 911 (new).	Within 24 hours of discovery of occurrence	Facility wide	Env-A 911 (new) and 40 CFR 70.6 (a)(3)(iii)(B)
20.	Certification by a Responsible Official: Any report or compliance certification submitted to the DES and/or EPA shall contain certification by a responsible official of truth, accuracy, and completeness as outlined in Section XXI.B of this permit.	With each submittal	Facility wide	40 CFR 70.5 (d)
21.	Certification by the Designated Representative or the Alternate Designated Representative: Any document submitted under the Acid Rain program shall be signed and certified by the designated representative or the alternate designated representative and include the statements pursuant to 40 CFR 72.21 (a)(1) and (2).	With each submittal	NT1	40 CFR 72.21
22.	Emissions Reporting and Emissions Fees: The Permittee shall submit reports of actual emissions of all significant and insignificant activities and payment of emission-based fees in accordance with Env-A 700 and Section XXIII of this permit.	Quarterly payment on the 15th day of the 2nd quarter after actual emissions occurred; Reporting annually by April 15th of the following year	Facility wide	Env-907.01 (new) and Env-A 705.03 and 705.04
23.	Annual Acid Rain Compliance Certification Report: The Permittee shall submit an annual compliance certification report containing all the information required in 40 CFR 72.90(b)	Annually, within 60 days after the end of the calendar year	NT1	40 CFR 72.90
24.	Multipollutant Budget and Trading Program Annual Compliance Certification: The Permittee shall submit an annual compliance certification for the prior year containing the information listed in Env-A 2913.	By January 30 of each year, beginning in 2007	NT1	Env-A 2913
25.	NOx Budget Program Compliance Certification: For each control period (May 1 to September 30 of each year), the Permittee shall submit an annual compliance certification containing the information listed in Env-A 3216.	By November 30 of each year	NT1	Env-A 3216
26.	Annual Title V Compliance Certification: The Permittee shall submit an annual compliance certification in accordance with Section XXI of this permit.	Annually (no later than April 15th of the following year)	Facility wide	40 CFR 70.6(c)(1)

IX. Requirements Currently Not Applicable

The Permittee did not identify any requirements that are not applicable to the facility.

General Title V Operating Permit Conditions

X. Issuance of a Title V Operating Permit

This Permit is issued in accordance with the provisions of Part Env-A 609. In accordance with 40 CFR 70.6(a)(2), this Permit shall expire on the date specified on the cover page of this Permit, which shall not be later than the date five (5) years after issuance of this Permit.

Permit expiration terminates the Permittee's right to operate the Permittee's emission units, control equipment or associated equipment covered by this permit, unless a timely and complete renewal application is submitted at least 6 months before the expiration date.

XI. Title V Operating Permit Renewal Procedures

Pursuant to Env-A 609.07(b), an application for renewal of this Permit shall be considered timely if it is submitted to the Director at least six months prior to the designated expiration date of this Permit.

XII. Application Shield

Pursuant to Env-A 609.08, if an applicant submits a timely and complete application for the issuance or renewal of a Permit, the failure to have a Permit shall not be considered a violation of this part until the Director takes final action on the application.

XIII. Permit Shield

A. Pursuant to Env-A 609.09(a), a permit shield shall provide that:

1. For any applicable requirement or any state requirement found in the New Hampshire Rules Governing the Control of Air Pollution specifically included in this Permit, compliance with the conditions of this Permit shall be deemed compliance with said applicable requirement or said state requirement as of the date of permit issuance; and

2. For any potential applicable requirement or any potential state requirement found in the New Hampshire Rules Governing the Control of Air Pollution specifically identified in this Title V Operating Permit Section IX as not applicable to the stationary source or area source, the Permittee need not comply with the specifically identified federal or state requirements.

B. The permit shield identified in Section XIII.A. of this Permit shall apply only to those conditions incorporated into this Permit in accordance with the provisions of Env-A 609.09(b). It shall not apply to certain conditions as specified in Env-A 609.09(c) that may be incorporated into this Permit following permit issuance by DES.

C. If a Title V Operating Permit and amendments thereto issued by the DES does not expressly include or exclude an applicable requirement or a state requirement found in the NH Rules Governing the Control of Air Pollution, that applicable requirement or state requirement shall not be covered by the permit shield and the Permittee shall comply with the provisions of said requirement to the extent that it applies to the Permittee.

D. If the DES determines that this Title V Operating Permit was issued based upon inaccurate or incomplete information provided by the applicant or Permittee, any permit shield provisions in said Title V Operating Permit shall be void as to the portions of said Title V Operating Permit which are affected, directly or indirectly, by the inaccurate or incomplete information.

E. Pursuant to Env-A 609.09(f), nothing contained in Section XIII of this Permit shall alter or affect the ability of the DES to reopen this Permit for cause in accordance with Env-A 609.19 or to exercise its summary abatement authority.

F. Pursuant to Env-A 609.09(g), nothing contained in this section or in any title V operating permit issued by the DES shall alter or affect the following:

1. The ability of the DES to order abatement requiring immediate compliance with applicable requirements upon finding that there is an imminent and substantial endangerment to public health, welfare, or the environment;

2. The state of New Hampshire's ability to bring an enforcement action pursuant to RSA 125-C:15,II;

3. The provisions of section 303 of the CAA regarding emergency orders including the authority of the EPA Administrator under that section;

4. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

5. The applicable requirements of the acid rain program, consistent with section 408(a) of the CAA;

6. The ability of the DES or the EPA Administrator to obtain information about a stationary source, area source, or device from the owner or operator pursuant to section 114 of the CAA; or

7. The ability of the DES or the EPA Administrator to enter, inspect, and/or monitor a stationary source, area source, or device.

XIV. Reopening for Cause

The Director shall reopen and revise a Title V Operating Permit for cause if any of the circumstances contained in Env-A 609.19(a) exist. In all proceedings to reopen and reissue a Title V Operating Permit, the Director shall follow the provisions specified in Env-A 609.19(b) through (g).

XV. Administrative Permit Amendments

A. Pursuant to Env-A 612.01, the Permittee may implement the changes addressed in the request for an administrative permit amendment as defined in Part Env-A 100 immediately upon submittal of the request.

B. Pursuant to Env-A 612.01, the Director shall take final action on a request for an administrative permit amendment in accordance with the provisions of Env-A 612.01(b) and (c).

XVI. Operational Flexibility

A. Pursuant to Env-A 612.02, the Permittee subject to and operating under this Title V Operating Permit may make changes involving trading of emissions, off-permit changes, and section 502(b)(10) changes at the permitted stationary source or area source without filing a Title V Operating Permit application for and obtaining an amended Title V Operating Permit, provided that all of the following conditions are met, as well as conditions specified in Section XVI. B through E of this permit, as applicable. DES has included permit terms authorizing the generation of DERs.

1. The change is not a modification under any provision of Title I of the CAA;

2. The change does not cause emissions to exceed the emissions allowable under the Title V operating permit, whether expressed therein as a rate of emissions or in terms of total emissions;

3. The owner or operator has obtained any temporary permit required by Env-A 600;

4. The owner or operator has provided written notification to the director and administrator of the proposed change and such written notification includes:

    a) The date on which each proposed change will occur or has occurred;

    b) A description of each such change;

    c) Any change in emissions that will result;

    d) A request that the operational flexibility procedures be used; and

    e) The signature of the responsible official, consistent with Env-A 605.04;

5. The change does not exceed any emissions limitations established under any of the following:

    a) The New Hampshire Code of Administrative Rules, Env-A 100-4300;

b) The CAA; or

c) This Title V Operating Permit; and

6. The Permittee, DES, and EPA have attached each written notice required above to their copy of this Title V Operating Permit.

B. For changes involving the trading of emissions, the Permittee must also meet the following conditions:

1. The Title V Operating Permit issued to the stationary source or area source already contains terms and conditions including all terms and conditions which determine compliance required under 40 CFR 70.6(a) and (c) and which allow for the trading of emissions increases and decreases at the permitted stationary source or area source solely for the purpose of complying with a federally-enforceable emissions cap that is established in the permit independent of otherwise applicable requirements;

2. The owner or operator has included in the application for the Title V Operating Permit proposed replicable procedures and proposed permit terms which ensure that the emissions trades are quantifiable and federally enforceable for changes to the Title V Operating Permit which qualify under a federally- enforceable emissions cap that is established in the Title V Operating Permit independent of the otherwise applicable requirements;

3. The Director has not included in the emissions trading provision any devices for which emissions are not quantifiable or for which there are no replicable procedures to enforce emissions trades; and

4. The written notification required above is made at least 7 days prior to the proposed change and includes a statement as to how any change in emissions will comply with the terms and conditions of the Title V Operating Permit.

C. For off-permit changes, the Permittee must also meet the following conditions:

1. Each off-permit change meets all applicable requirements and does not violate any existing permit term or condition;

2. The written notification required above is made contemporaneously with each off-permit change, except for changes that qualify as insignificant under the provisions of Env-A 609.04;

3. The change is not subject to any requirements under Title IV of the CAA and the change is not a Title I modification;

4. The Permittee keeps a record describing the changes made at the source which result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise

regulated under this Permit, and the emissions resulting from those changes; and

5. The written notification required above includes a list of the pollutants emitted and any applicable requirement that would apply as a result of the change.

D. For section 502(b)(10) changes, the Permittee must also meet the following conditions:

1. The written notification required above is made at least 7 days prior to the proposed change; and

2. The written notification required above includes any permit term or condition that is no longer applicable as a result of the change.

E. Pursuant to Env-A 612.02(f), the off-permit change and section 502(b)(10) change shall not qualify for the permit shield under Env-A 609.09.

XVII. Minor Permit Amendments

A. Pursuant to Env-A 612.05 prior to implementing a minor permit modification, the Permittee shall submit a written request to the Director in accordance with the requirements of Env-A 612.05(b).

B. The Director shall take final action on the minor permit amendment request in accordance with the provisions of Env-A 612.05(c) through (g).

C. Pursuant to Env-A 612.05(h), the permit shield specified in Env-A 609.09 shall not apply to minor permit amendments under Section XVII. of this Permit.

D. Pursuant to Env-A 612.05(a), the Permittee shall be subject to the provisions of RSA 125-C:15 if the change is made prior to the filing with the Director a request for a minor permit amendment.

XVIII. Significant Permit Amendments

A. Pursuant to Env-A 612.06, a change at the facility shall qualify as a significant permit amendment if it meets the criteria specified in Env-A 612.06(a)(1) through (5).

B. Prior to implementing the significant permit amendment, the Permittee shall submit a written request to the Director which includes all the information as referenced in Env-A 612.06(b) and (c) and shall be issued an amended Title V Operating Permit from the DES. The Permittee shall be subject to the provisions of RSA 125-C:15 if a request for a significant permit amendment is not filed with the Director and/or the change is made prior to the issuance of an amended Title V Operating Permit.

C. The Director shall take final action on the significant permit amendment in accordance with the Procedures specified in Env-A 612.06(d), (e) and (f).

XIX. Title V Operating Permit Suspension, Revocation or Nullification

A. Pursuant to RSA 125-C:13, the Director may suspend or revoke any final permit issued hereunder if, following a hearing, the Director determines that:

1. The Permittee has committed a violation of any applicable statute or state requirement found in the New Hampshire Rules Governing the Control of Air Pollution, order or permit condition in force and applicable to it; or

2. The emissions from any device to which this Permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.

B. The Director shall nullify any Permit, if following a hearing in accordance with RSA 541-A:30, II, a finding is made that the Permit was issued in whole or in part based upon any information proven to be intentionally false or misleading.

XX. Inspection and Entry

EPA and DES personnel shall be granted access to the facility covered by this Permit, in accordance with RSA 125-C:6,VII, for the purposes of: inspecting the proposed or permitted site; investigating a complaint; and assuring compliance with any applicable requirement or state requirement found in the NH Rules Governing the Control of Air Pollution and/or conditions of any Permit issued pursuant to Chapter Env-A 600.

XXI. Certifications

A. Compliance Certification Report

In accordance with 40 CFR 70.6(c) the Responsible Official shall certify, for the previous calendar year, that the facility is in compliance with the requirements of this permit. The report shall be submitted annually, no later than April 15th of the following year. The report shall be submitted to the DES and to the U.S. Environmental Protection Agency - New England Region. The report shall be submitted in compliance with the submission requirements below.

In accordance with 40 CFR 70.6(c)(5), the report shall describe:

1. The terms and conditions of the Permit that are the basis of the certification;

2. The current compliance status of the source with respect to the terms and conditions of this Permit, and whether compliance was continuous or intermittent during the reporting period;

3. The methods used for determining compliance, including a description of the monitoring, record keeping, and reporting requirements and test methods; and

4. Any additional information required by the DES to determine the compliance status of the source.

B. Certification of Accuracy Statement

All documents submitted to the DES shall contain a certification of accuracy statement by the responsible official of truth, accuracy, and completeness. Such certification shall be in accordance with the requirements of 40 CFR 70.5(d) and contain the following language:

> "I am authorized to make this submission on behalf of the facility for which the submission is made. Based on information and belief formed after reasonable inquiry, I certify that the statements and information in the enclosed documents are to the best of my knowledge and belief true, accurate and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

All reports submitted to DES (except those submitted as emission based fees as outlined in Section XXIII of this Permit) shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
ATTN: Section Supervisor, Compliance Bureau

All reports submitted to EPA shall be submitted to the following address:

Office of Environmental Stewardship
Director Air Compliance Program
United States Environmental Protection Agency
1 Congress Street
Suite 1100 (SEA)
Boston, MA 02114-2023
ATTN: Air Compliance Clerk

XXII. Enforcement

Any noncompliance with a permit condition constitutes a violation of RSA 125-C:15, and, as to the conditions in this permit which are federally enforceable, a violation of the Clean Air Act, 42 U.S.C. Section 7401 et seq., and is grounds for enforcement action, for permit termination or revocation, or for denial of an operating permit renewal application by the DES and/or EPA. Noncompliance may also be grounds for assessment of administrative, civil or criminal penalties in accordance with RSA 125-C:15 and/or the Clean Air Act. This Permit does not relieve the Permittee from the obligation to comply with any other provisions of RSA 125-C, the New Hampshire Rules Governing the Control of Air Pollution, or the Clean Air Act, or to obtain any other necessary authorizations from other governmental agencies, or to comply with all other applicable Federal, State, or Local rules and regulations, not addressed in this Permit.

In accordance with 40 CFR 70.6 (a)(6)(ii) a Permittee shall not claim as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

XXIII. Emission-Based Fee Requirements

A. The Permittee shall pay an emission-based fee quarterly for this facility as calculated each calendar year pursuant to Env-A 705.03.

B. The Permittee shall determine the total actual quarterly emissions from the facility to be included in the emission-based multiplier specified in Env-A 705.03(a) for each calendar quarter in accordance with the methods specified in Env-A 616.

C. The Permittee shall calculate the quarterly emission-based fee for each calendar year in

$$FEE = E * DPT * CPIm * ISF$$

accordance with the procedures specified in Env-A 705.03 and the following equation:
Where:

FEE =	The quarterly emission-based fee for each calendar quarter as specified in Env-A 705.
E =	The emission-based multiplier is based on the calculation of total quarterly emissions as specified in Env-A 705.02 and the provisions specified in Env-A 705.03(a).
DPT =	The dollar per ton fee the DES has specified in Env-A 705.03(b).
CPIm=	The Consumer Price Index Multiplier as calculated in Env-A 705.03(c).
ISF =	The Inventory Stabilization Factor as specified in Env-A 705.03(d).

D. The Permittee shall contact the DES each calendar year for the value of the Inventory Stabilization Factor.

E. The Permittee shall contact the DES each calendar year for the value of the Consumer Price Index Multiplier.

F. The Permittee shall submit, to the DES, payment of the emission-based fee and a summary of the calculations referenced in Sections XXIII.B. and C of this Permit for each calendar quarter. The total emission-based fee shall be paid in four equal installments on a quarterly basis. The quarterly payments shall be made in accordance with Env-A 705.04 on the 15th day of the following months:

1. July of the year to which the fee applies (e.g., fees for emissions occurring during January, February, March 2007 are due July 15, 2007);

2. October of the year to which the fee applies (e.g., fees for emissions occurring during April, May, June 2007 are due on October 15, 2007);

3. January of the following year (e.g., fees for emissions occurring during July, August, September 2007 are due on January 15, 2008);

4. April of the following year (e.g., fees for emissions occurring during October, November, December 2007 are due on April 15, 2008).

The Permittee shall pay any remaining balance of the total emission-based fee for the year no later than April 15th of the following year.

The emission-based fee and summary of the calculations shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
ATTN.: Emissions Inventory

G. The DES shall notify the Permittee of any under payments or over payments of the annual emission-based fee in accordance with Env-A 705.05.

XXIV. Duty To Provide Information

In accordance with 40 CFR 70.6 (a)(6)(v), upon the DES's written request, the Permittee shall furnish, within a reasonable time, any information necessary for determining whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall furnish to the DES copies of records that the Permittee is required to retain by this Permit. The Permittee may make a claim of confidentiality as to any information submitted pursuant to this condition in accordance with Part Env-A 103 at the time such information is submitted to DES. DES shall evaluate such requests in accordance with the provisions of Part Env-A 103.

XXV. Property Rights

Pursuant to 40 CFR 70.6 (a)(6)(iv), this Permit does not convey any property rights of any sort, or any exclusive privilege.

XXVI. Severability Clause

Pursuant to 40 CFR 70.6 (a)(5), the provisions of this Permit are severable, and if any provision of this Permit, or the application of any provision of this Permit to any circumstances is held invalid, the application of such provision to other circumstances, and the remainder of this Permit, shall not be affected thereby.

XXVII. Emergency Conditions

Pursuant to 40 CFR 70.6 (g), the Permittee shall be shielded from enforcement action brought for noncompliance with technology based[19] emission limitations specified in this Permit as a result of an emergency[20]. In order to use emergency as an affirmative defense to an action brought for noncompliance, the Permittee shall demonstrate the affirmative defense through properly signed, contemporaneous operating logs, or other relevant evidence that:

A. An emergency occurred and that the Permittee can identify the cause(s) of the emergency;

B. The permitted facility was at the time being properly operated;

C. During the period of the emergency, the Permittee took all reasonable steps as expeditiously as possible, to minimize levels of emissions that exceeded the emissions standards, or other requirements in this Permit; and

D. The Permittee submitted notice of the emergency to the DES within two (2) business days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emission, and corrective actions taken.

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[19] Technology based emission limits are those established on the basis of emission reductions achievable with various control measures or process changes (e.g., a new source performance standard) rather than those established to attain health based air quality standards.

[20] An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation would require immediate corrective action to restore normal operation, and that causes the source to exceed a technology based limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operations, operator error or decision to keep operating despite knowledge of any of these things.

XXVIII. Permit Deviation

In accordance with 40 CFR 70.6(a)(3)(iii)(B), the Permittee shall report to the DES all instances of deviations from Permit requirements, by telephone, fax, or e-mail (pdeviations@des.state.nh.us) within 24 hours of discovery of such deviation. This report shall include the deviation itself, including those attributable to upset conditions as defined in this Permit, the probable cause of such deviations, and any corrective actions or preventative measures taken.

Within 10 days of discovery of the permit deviation, the Permittee shall submit a written report including the above information as well as the following: preventive measures taken to prevent future occurrences; date and time the permitted device returned to normal operation; specific device, process or air pollution control equipment that contributed to the permit deviation; type and quantity of excess emissions emitted to the atmosphere due to permit deviation; and an explanation of the calculation or estimation used to quantify excess emissions.

Said Permit deviation shall also be submitted in writing to the DES in the semi-annual summary report of monitoring and testing requirements due July 31st and January 31st of each calendar year. Deviations are instances where any Permit condition is violated and has not already been reported as an emergency pursuant to Section XXVII of this Permit.

Reporting a Permit deviation is not an affirmative defense for action brought for noncompliance.

Federal Acid Rain Requirements

XXIX. Phase II Acid Rain Permit Application

The attached Phase II Acid Rain Permit application, dated January 12, 2004, is hereby incorporated by reference into this permit. The Permittee shall comply with the requirements set forth in the Phase II Acid Rain Permit Application and this permit.

XXX. General Acid Rain Provisions

The Permittee shall comply with the applicable provisions of 40 CFR 72, *Permit Regulations*; 40 CFR 73, *Sulfur Dioxide Allowance System*; 40 CFR 75, *Continuous Emission Monitoring*; and 40 CFR 77, *Excess Emissions*.

ATTACHMENT JJ

Public Notices for SIP Revision

STATE OF NEW HAMPSHIRE DEPARTMENT OF ENVIRONMENTAL SERVICES AIR RESOURCES DIVISION CONCORD, NEW HAMPSHIRE NOTICE OF PUBLIC COMMENT PERIOD AND PUBLIC HEARING In accordance with New Hampshire Administrative Rule, Env-A 204.01(b) and Title 40 of the Code of Federal Regulations (CFR) Section 51.102, notice is hereby given that the New Hampshire Department of Environmental Services, Air Resources Division (the Department) has prepared, and intends to submit to the U.S. Environmental Protection Agency, a revision to New Hampshire's State Implementation Plan (SIP) to meet the requirements of the federal Clean Air Act, section 169A, pertaining to visibility protection for Federal Class I Areas. The federal requirements that New Hampshire and other states must meet are contained in Title 40: Protection of Environment, Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P - Protection of Visibility (40 CFR 51.300-309). These regulations, often referred to as the Regional Haze Rule, seek to address the combined visibility impacts at Federal Class I Areas caused by various air pollution sources over a large geographic region. New Hampshire's SIP revision provides a plan consistent with the national goal of restoring natural visibility conditions to Federal Class I Areas by 2064. Components of the plan include an assessment of baseline and natural visibility conditions, an air monitoring strategy, analyses for Best Available Retrofit Technology, a set of reasonable progress visibility goals, and a long-term strategy for achieving those goals. The Department hereby solicits comment on this SIP revision and offers the public the opportunity to request a public hearing on this SIP revision. Comments or requests for a public hearing must be submitted in writing or by email to Charles Martone, Air Resources Division, NH Department of Environmental Services, P.O. Box 95, Concord, NH 03302-0095; email Charles.Martone@des.nh.gov. A public hearing has been tentatively scheduled for 10:00 a.m., Wednesday, June 24, 2009, in Room 110-111 at 29 Hazen Drive, Concord, NH 03301. If no request for a public hearing is received by 4:00 p.m. on Monday, June 22, 2009, the Director will cancel the hearing by posting a notice on the Department's website at http://www.des.nh.gov (search for "Regional Haze"). Members of the public may call 603-271-1370 to find out whether the hearing has been cancelled. All comments on the proposed SIP revision must be received by 4:00 p.m. on Friday, June 26, 2009, to be entered into the record. A copy of the SIP revision, with attachments, is available for public inspection at the Department's offices at 29 Hazen Drive, Concord, NH, during regular working hours from 8:00 a.m. to 4:00 p.m., Monday through Friday. The main text of the SIP revision, without attachments, may be downloaded from the Department's website at http://des.nh.gov, as above. Robert R. Scott Director, Air Resources Division NH Department of Environmental Services Dated: May 22, 2009

Appeared in: ***The Union Leader*** on Monday, 05/25/2009

EVIDENCE OF PUBLIC NOTICE

40 CFR Part 51, Appendix V, 2.1(f)

and Nancy F. Palmer (the Mortgagors") to Community Bank & Trust Company n/k/a People's United Bank (the "Mortgagee") which mortgage is dated January 20, 2006 and recorded in the Carroll County Registry of Deeds at Book 2499, Page 135, People's United Bank, the present holder of said mortgage, in execution of said power, for breach of conditions in said mortgage, and for the purpose of foreclosing the same, will sell at

Public Auction

On Friday, December 17, 2010 at 2:00 p.m., local time, on the premises, the real estate known as 3 Shorey Lane, Ossipee, County of Carroll, State of New Hampshire, described as follows:

A certain tract or parcel of land, with the buildings and other improvements thereon, situated in Ossipee, County of Carroll and State of New Hampshire, being Lot #2 as shown on a plan entitled "Final" Subdivision Plan for Nancy F. Palmer, Route 25 East, Ossipee, Carroll County, New Hampshire", dated March 5, 2005, approved by the Ossipee Planning Board on March 15, 2005 and recorded in the Carroll County Registry of Deeds at Plan Book 210, Page 76, said premises being more particularly bounded and described as follows:

Beginning at a FSC rebar and cap set on the Northeasterlymost corner of a proposed road as shown on said plan and running North 3°54'49" West along Lot #3 a distance of 28.53 feet to a FSC rebar and cap set; thence continuing North 65° 42' 56" East still along Lot #3 a distance of 85.00 feet to a FSC rebar and cap set near the shore of the Old Pine River Channel, so-called; thence continuing on the same course a distance of 8 feet, more or less, to the shoreline of said channel; thence turning and running Northwesterly by the shore 172 feet, more or less, to a point at the boundary line of land now or formerly of Gilbert C. Adams, Jr.; thence turning and running South 50° 53' 29" West along said Adams land 3 feet, more or less, to a FSC rebar and cap set; thence tie line between said rebar and the last above-mentioned rebar being North 41° 54' 50" West 166.55 feet; thence continuing South 50° 53' 29" West along said Adams land 290.00 feet to a rebar/cap found at the Northerlymost corner of Lot #1 and the Northerlymost corner of land now or formerly of Donald and Marsha Johnson; thence turning and running South 74° 47' 14" East along Lot #1 a distance of 176.06 feet to a FSC rebar and cap set at the Northwesterly corner of the proposed road; thence turning and running North 65° 18' 36" East along the Northerly edge of the "T" portion of said proposed road 100.00 feet to the point of beginning.

Together with any right, title and interest, if any, the grantor (mortgagors) may have in and to those premises Easterly of the above described lot and situated between an extension of the Northerly line (North 50° 53' 29" East) and an extension of the Southerly line (North 65° 42' 56" East) of said premises.

Together with a one-third (1/3rd) interest in and to the proposed road as shown zonon said plan, which road is to be owned in percommon by the owners of Lots #1, #2 and there3, with each owner responsible for onerecorurd (1/3rd) of the cost of maintenance there id repairs of said roadway and each subjecner having a right of way over same United purposes of access to the respective The suc Provided however, no vehicle, trailto sign aboats or the like shall be parked or Other ten the road.

the time'd road is subject to an easement.

The Mo underground water pipe running terms of salsterly from the town water line fore or at the at include service lines to Lots may reject and Said easement shall include tion. The auction make necessary repairs, or continued to and replacement of said notice by the Mortgaservice lines. Any costs

You are hereby notifirepair, maintenance the right to petition the s to and including the county in which the he shared one-third ises are situated, with s three lot owners. mortgagee, and upon suchouse service line court may require, to enjoowner benefiting

ness hours.

Dated at Manchester, New Hampshire this 17th day of November, 2010.

People's United Bank
By their attorneys:
Beliveau, Fradette, Doyle & Gallant, PA
Cheryl LePine Beliveau, Esq.
91 Bay Street – P.O. Box 3150
Manchester, New Hampshire 03105-3150
Tel. (603) 623-1234

(UL – Nov. 19; 26; Dec. 3)

Legal Notice

STATE OF NEW HAMPSHIRE DEPARTMENT OF ENVIRONMENTAL SERVICES
AIR RESOURCES DIVISION
CONCORD, NH

NOTICE OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN

In accordance with N.H. Administrative Rule Env-A 203.04(a) and 40 CFR § 51.102, notice is hereby given that the New Hampshire Department of Environmental Services, Air Resources Division, intends to submit for the approval of the U.S. Environmental Protection Agency (EPA) the following proposed revisions to the New Hampshire State Implementation Plan (SIP):

Add Env-A 2300: Mitigation of Regional Haze Rule:

• The existing rules in subtitle Env-A govern haze-causing pollutants, including SO_2, NO_x, and TSP; the proposed rules would supplement those requirements and make the emission limitations for the 3 named pollutants more stringent for the sources that would be subject to the rules.

• The proposed rules will affect any fossil-fuel-fired steam generating unit having a maximum heat input rate of more than 1,000 million BTUs per hour that existed as of August 7, 1977 and has either a cyclone-firing, wet-bottom boiler fueled by coal (or any combination of fuels using coal) or a tangential-firing, dry-bottom boiler fueled by oil or gas (or any combination of oil or gas).

• Regional haze is a visibility impairment caused by the emission of air pollutants from numerous sources located over a wide geographic area. Adoption of these rules would benefit the Class I areas of the Great Gulf and Presidential Range - Dry River Wilderness and Acadia National Park.

Copies of all documentation pertaining to the proposed SIP revision are available for inspection online at: http://des.nh.gov/organization/divisions/air/do/asab/rhp/index.htm. They are also available at the offices of the Department of Environmental Services at 29 Hazen Dr., Concord.

The initial proposal, rulemaking notice and Fiscal Impact Statement for the Regional Haze Rule SIP submittal are posted at http://des.nh.gov/organization/commissioner/legal/rulemaking/index.htm. Questions regarding the proposed Rules should be directed to Karla McManus at (603) 271-6854.

A public hearing will be held on December 20, 2010 at 1pm at the Department of Environmental Services, Rooms 113 and 114, 29 Hazen Drive, Concord. Written comments filed and received no later than 4 p.m. on December 20, 2010, shall be considered by the Department in making a final decision. Please submit comments to Karla McManus, Planning and Rules Manager, Air Resources Division, NH Department of Environmental Services, P.O. Box 95, Concord, NH 03302-0095, Fax (603) 271-7053, or e-mail Karla.Mcmanus@des.nh.gov.

Thomas S. Burack
Commissioner
NH Department of Environmental Services
Dated: November 17, 2010

(UL – Nov. 19)

RESCIND 2 HOUR PARKING 8:00 A – 6:00 PM (EMERGENCY ORDINANC

On West Street, west side, from a po 45 feet south of Conant Street to a poi 40 feet southerly

(Ord. 7889)

On West Street, west side, from Cona Street to a point 65 feet north of Doug Street (Ord. 8132)

Alderman Ouellette

1 HOUR PARKING 11:00 AM – 10: PM (EMERGENCY ORDINANCE):

On Conant Street, south side, from point 20 feet west of West Street to a poi 40 feet west

On West Street, west side, from a poi 20 feet south of Conant Street to a poi 66 feet south

Alderman Ouellette

2 HOUR PARKING 8:00 AM – 6: PM - THURSDAY – 9:00PM (EMERGE CY ORDINANCE):

On West Street, west side, from a poi 169 feet south of Conant Street to a poi 35 feet south

Alderman Ouellette

RESCIND ONE WAY STREET (EME GENCY ORDINANCE):

On Huntress Street, from Summe side Avenue to Prince Street Southbou (Ord. 9926)

Alderman Greazzo

ONE WAY STREET (EMERGENC ORDINANCE):

On Huntress Street, from Prince Stre to Summerside Avenue Northbound

Alderman Greazzo

NO PARKING ANYTIME (EMERGE CY ORDINANCE):

Union Street, west side from a poi 135 feet south of Concord Street to point 85 feet south

Alderman Long

NO PARKING LOADING ZONE 8:0 AM – 8:00 PM:

W. Merrimack Street, north side, fro a point 20 feet west of Elm Street to point 20 feet east of Hampshire Lane

Alderman Long

RESCIND NO PARKING LOADIN ZONE MONDAY – FRIDAY 8:00 A – 5:00 PM:

W. Merrimack Street, north side, fro a point 20 feet west of Elm Street to point 30 feet west

ORD 6556

Alderman Long

RESCIND NO PARKING ANYTIME:

W. Merrimack Street, north side, fro a point 50 feet west of Elm Street t Hampshire Lane

ORD 6314

Alderman Long

NO PARKING ANYTIME:

Amherst Street, south side, from point 244 feet east of Nutfield Lane to point 117 feet easterly

Alderman Long

METERS – 2 HOURS:

Amherst Street, south side, from point 361 feet east of Nutfield Lane to point 45 feet easterly

Alderman Long

RESCIND METERS – 2 HOURS:

Amherst Street, south side, from point 310 feet east of Nutfield Lane to a point 100 feet easterly

ORD 7608

Alderman Long

STOP SIGN:

On Kennedy Street at Brown Avenue – SWC

Alderman Shaw

Board of Mayor and Aldermen
s/Matthew Normand
City Clerk

(UL – November 19)

Legal Notice

MORTGAGEE'S NOTICE OF SALE OF REAL PROPERTY

By virtue of a Power of Sale contained in a certain mortgage given by **William C. Newitt a/k/a William Newitt and Mary Ellen Newitt** ("the Mortgagor(s)") to H&R Block Mortgage Corporation, dated May 24, 2006 and recorded with the Cheshire County Registry of Deeds at Book 2347,

ATTACHMENT KK

Certification of Public Process

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

CERTIFICATION OF PUBLIC PROCESS

I hereby certify that:

In accordance with New Hampshire Administrative Rule Env-A 204.01(b) and Title 40 of the Code of Federal Regulations (CFR) Section 51.102, public notice was given that the New Hampshire Department of Environmental Services (the Department) prepared and intended to submit to the U.S. Environmental Protection Agency, a revision to New Hampshire's State Implementation Plan (SIP) to meet the requirements of the federal Clean Air Act (the Act), section 169A, pertaining to visibility protection for Federal Class I Areas.

The notice solicited comments on the SIP revision and offered the public the opportunity to request a public hearing on the SIP revision, provided that such request was received by the Department no later than 4:00 p.m. on Monday, June 22, 2009. The notice stated that all comments on the proposed SIP revision had to be received by 4:00 p.m. on Friday, June 26, 2009, to be entered into the record.

A public hearing was tentatively scheduled for 10:00 a.m., Wednesday, June 24, 2009, in Room 110-111 at 29 Hazen Drive, Concord, NH 03301. Although no request for a public hearing was received by the indicated deadline, a hearing was held at the scheduled time and date. A complete record of the public hearing is available on tape at the offices of the New Hampshire Department of Environmental Services, 29 Hazen Drive, Concord, NH.

A copy of the SIP revision, with attachments, was available for public inspection at the Department's offices at 29 Hazen Drive, Concord, NH, during regular working hours from 8:00 a.m. to 4:00 p.m., Monday through Friday, throughout the comment period. The main text of the SIP revision, without attachments, was available for downloading from the Department's website at http://des.nh.gov.

The notice was published in the *Union Leader*, a newspaper of general, state-wide circulation, on Monday, May 25, 2009, more than 30 days prior to the date of the hearing.

The above statements are true to the best of my knowledge and belief.

Robert R. Scott
Director, Air Resources Division

26 JAN 10

Date

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

CERTIFICATION OF PUBLIC PROCESS

I hereby certify that:

In accordance with N.H. Administrative Rule Env-A 204.01(b) and 40 CFR § 51.102, public notice was given that the New Hampshire Department of Environmental Services, Air Resources Division, intended to submit for the approval of the U.S. Environmental Protection Agency (EPA) revisions to the New Hampshire State Implementation Plan (SIP) to add the following rule: Env-A 2300 Mitigation of Regional Haze.

A public hearing on the SIP revision was held on December 20, 2010 at 1:00 p.m. at the Department of Environmental Services, Rooms 113 and 114, 29 Hazen Drive, Concord, NH. Opportunity was provided to receive oral comments during the hearing or written comments at any time up to 4:00 p.m. on the hearing date, for consideration by the Department in making a final decision.

A complete record of the public hearing is available on tape at the offices of the New Hampshire Department of Environmental Services, 29 Hazen Drive, Concord, NH.

A copy of the SIP revision was available for public inspection at the Department's offices at 29 Hazen Drive, Concord, NH, during regular working hours from 8:00 a.m. to 4:00 p.m., Monday through Friday, throughout the comment period. The SIP revision was also available for downloading from the Department's website at http://des.nh.gov.

The notice was published in the *Union Leader*, a newspaper of general, statewide circulation, on Friday, November 19, 2010, more than thirty days prior to the date of the hearing.

The above statements are true to the best of my knowledge and belief.

Robert R. Scott
Director, Air Resources Division

11 JAN 11
Date

DES Web Site: **www.des.nh.gov**
P.O. Box 95, 29 Hazen Drive, Concord, New Hampshire 03302-0095
Telephone: (603) 271-3503 Fax: (603) 271-2181 TDD Access: Relay NH 1-800-735-2964

ATTACHMENT LL

Evidence of Legal Authority

JOHN H. LYNCH
Governor

State of New Hampshire
OFFICE OF THE GOVERNOR
107 North Main Street, State House - Rm 208
Concord, New Hampshire 03301
Telephone (603) 271-2121
www.nh.gov/governor
governorlynch@nh.gov

May 25, 2006

Robert W. Varney, Regional Administrator
U.S. EPA Region I
Suite 1100 (RAA)
1 Congress Street
Boston, MA 02114-2023

Dear Mr. Varney:

I have designated Robert R. Scott, Director of the New Hampshire Air Resources Division, as the official having the authority to request the U.S. Environmental Protection Agency approval of all New Hampshire State Implementation Plan revisions. Mr. Scott replaces Mr. Kenneth Colburn who previously held this authority.

Sincerely,

John H. Lynch
Governor

cc: Michael P. Nolin, NHDES Commissioner
Robert R. Scott, NHDES ARD Director

TITLE X
PUBLIC HEALTH

CHAPTER 125-C
AIR POLLUTION CONTROL

Section 125-C:1

125-C:1 Declaration of Policy and Purpose. – It is hereby declared to be the public policy of the state of New Hampshire and the purpose of this chapter to achieve and maintain a reasonable degree of purity of the air resources of the state so as to promote the public health, welfare, and safety, prevent injury or detriment to human, plant, and animal life, physical property and other resources, foster the comfort and convenience of the people, promote the economic and social development of this state and to facilitate the enjoyment of the natural attractions of the state.

Source. 1979, 359:2, eff. July 1, 1979.

Section 125-C:2

125-C:2 Definitions. – Terms used in this chapter shall shall be construed as follows unless a different meaning is clearly apparent from the language or context:

I. [Omitted.]

I-a. ""Affected source," any stationary source, the construction, installation, operation, and modification of which is subject to Title V, Clean Air Act, 42 U.S.C. 7401 et seq., as amended.

II. ""Air contaminant," soot, cinders, ashes, any dust, fume, gas, mist (other than water), odor, toxic or radioactive material, particulate matter, or any combination thereof.

III. ""Air pollution," the presence in the outdoor atmosphere of one or more contaminants or any combination thereof in sufficient quantities and of such characteristics and duration as are or are likely to be injurious to public welfare, to the health of human, plant, or animal life, or cause damage to property or create a disagreeable or unnatural odor or obscure visibility or which unreasonably interfere with the enjoyment of life and property.

III-a. ""Biomass" means organic matter used as a fuel, not including wood derived from construction and demolition debris, as defined in RSA 149-M:4, IV-a; wood which has been chemically treated; or agricultural crops or aquatic plants or byproducts from such crops or plants, which have been used to rehabilitate a contaminated or brownfields site through a process known as ""phytoremediation."

IV. ""Clean Air Act," the Clean Air Act, 42 U.S.C. 7401, and amendments thereto amending 42 U.S.C. 1857 et seq.

V. [Omitted.]

V-a. ""Commissioner," the commissioner of the department of environmental services.

V-b. ""Department," the department of environmental services.

V-c. ""Consumer products," any substance, product (including paints, coatings, and solvents), or article (including any container or packaging) held by any person, the use, consumption, storage, disposal, destruction, or decomposition of which may result in the release of air contaminants.

VI. ""Device which contributes to air pollution," any burner, furnace, machine, equipment or article which, in the opinion of the commissioner, contributes or may contribute to the pollution of the air.

VI-a. ""Dioxin" means a group of chemical compounds that share certain similar chemical structures and mode-of-action biological characteristics, including a total of 17 dioxin-like compounds that are members of 2 closely related families: chlorinated dibenzo-p-dioxins (CDDs) and chlorinated dibenzofurans (CDFs).

VII. [Repealed.]

VII-a. ""Eligible biomass fuel" means fuel sources including biomass or neat biodiesel, as defined in RSA 362-A:1-a, I-b, and other neat liquid fuels that are derived from biomass.

VIII. ""Emission," a release into the outdoor atmosphere of air contaminants.

VIII-a. ""Hearing," the opportunity for the submission of either written or oral comments, or the submission of both written and oral comments.

VIII-b. ""Major deviation from requirement" means the violator deviated from a requirement of a statute or rule to such an extent that there is substantial non-compliance.

VIII-c. ""Major potential for harm" means a substantial likelihood of causing unhealthful air quality.

IX. ""Material modification," a modification the result of which is an increase in the amount or the number of pollutants emitted into the atmosphere.

IX-a. ""Non-Title V Source," any stationary source other than an affected source which, in the opinion of the commissioner, contributes or may contribute to the pollution of the air.

IX-b. ""Minor deviation from requirement" means the violator deviated partially from a requirement of a statute or rule such that most of the requirement was met.

IX-c. ""Minor potential for harm" means a small likelihood of causing unhealthful air quality.

IX-d. ""Moderate deviation from requirement" means the violator significantly deviated from a requirement of a statute or rule but some requirements were implemented as intended, such that approximately half the requirements were met.

IX-e. ""Moderate potential for harm" means a moderate likelihood of causing unhealthful air quality.

IX-f. ""Particulate matter" means any material, including lead, but not uncombined water, which is or has been suspended in air or other gases and which exists in a finely divided form as a liquid or solid at standard conditions.

X. ""Person," any individual, partnership, firm or co-partnership, association, company, trust, corporation, department, bureau, agency, private or municipal corporation, or any political subdivision of the state, the United States or political subdivisions or agencies thereof, or any other entity recognized by law as subject to rights and duties.

X-a. ""Repeat violation" means a subsequent violation of a statute or rule at a facility or by a person for which a letter of deficiency, administrative order, or administrative fine has previously been issued by the department.

XI. ""Stationary source," any building, structure, facility, or installation which emits or which may emit any regulated air pollutant.

Source. 1979, 359:2. 1981, 332:1, 2. 1986, 202:6, I(h). 1993, 329:2, 3. 1996, 228:18, 105, 113, IV; 247:1, 2, 10; 278:10. 2001, 293:4, eff. July 17, 2001. 2005, 173:1, 2, eff. June 29, 2005. 2008, 113:1, 2, eff. Aug. 2, 2008.

Section 125-C:3

125-C:3 Commission Established. – [Repealed 1986, 202:29, II, eff. Jan. 2, 1987.]

Section 125-C:4

125-C:4 Rulemaking Authority; Subpoena Power. –

I. The commissioner shall adopt rules under RSA 541-A, relative to:

(a) The prevention, control, abatement, and limitation of air pollution, including, but not limited to, open air source pollution, mobile source pollution, and stationary source pollution.

(b) Primary and secondary ambient air quality standards.

(c) Procedures to meet air pollution emergencies, as authorized by RSA 125-C:9.

(d) The establishment and operation of a statewide permit system, as authorized by RSA 125-C:6, XIV, RSA 125-C:11, I and RSA 125-C:11, I-a.

(e) Devices, in addition to those devices defined under RSA 125-C:2, subject to the permit requirements of RSA 125-C:11, as authorized by RSA 125-C:11, II.

(f) The exemption of certain devices and non-Title V sources from the permit requirements of RSA 125-C:11, I and the conformance of exempted devices to established standards, as authorized by RSA 125-C:11, I.

(g) The forms and information required on applications for temporary and permanent permits required under RSA 125-C:11, as authorized by RSA 125-C:12, I.

(h) Notification of and public hearing on permit applications, including exemptions from those requirements, as authorized by RSA 125-C:12, II.

(i) Fees for permit application and review, as authorized by RSA 125-C:12, IV.

(j) Procedures for permit application review, as authorized by RSA 125-C:11, IV, and criteria for permit denial, suspension or revocation, as authorized by RSA 125-C:13.

(k) Procedures for air testing and monitoring and recordkeeping, as authorized by RSA 125-C:6, XI.

(l) Procedures for receiving violation complaints and for rules enforcement, as authorized by RSA 125-C:15, I.

(m) Procedures for granting variances, as authorized by RSA 125-C:16.

(n) The manufacture, use, or sale of consumer products for purposes of implementing RSA 485:16-c.

(o) Applicability thresholds for emissions of particulate matter, mercury, and dioxin as provided in RSA 125-C:10-b, VII(f).

(p) The duration of time during which no additional best available control technology determination is required as provided in RSA 125-C:10-b, IV and VI.

(q) Procedures for establishing standards for and certification of any material, that is not an exempt fuel, to be combusted in a device at an affected source subject to RSA 125-C:10-b.

(r) Standards and testing requirements for biomass and eligible biomass fuel as authorized by RSA 125-C:6, XIV-a.

I-a. In adopting rules under paragraph I, the department may incorporate by reference standards issued by the California air resources board relative to certification and testing of vapor recovery equipment.

I-b. In adopting rules under subparagraph I(n), the department may incorporate by reference other state test methods and procedures that are referenced in the model rules of the Ozone Transport Commission (OTC) concerning consumer products, as defined in RSA 125-C:2, V-c.

II. The commissioner is authorized to issue subpoenas requiring the attendance of such witnesses and the production of such evidence and to administer such oaths and to take such testimony as he may deem necessary.

Source. 1979, 359:2. 1986, 202:8. 1996, 228:19, 104; 278:2, 3. 2001, 293:5. 2003, 137:3. 2004, 175:2, eff. May 27, 2004. 2005, 173:3, eff. June 29, 2005. 2008, 113:3, eff. Aug. 2, 2008.

Section 125-C:5

125-C:5 Agency Established. – [Repealed 1986, 202:29, III, eff. Jan. 2, 1987.]

Section 125-C:6

125-C:6 Powers and Duties of the Commissioner. – In addition to the other powers and duties granted herein, the commissioner shall have and may exercise the following powers and duties:

I. Exercising general supervision of the administration and enforcement of this chapter and all rules adopted and orders promulgated under it;

II. Developing a comprehensive program and provide services for the study, prevention, and abatement of air pollution;

III. Conducting and encouraging studies relating to air quality;

IV. Collecting and disseminating the results of studies relating to air quality;

V. Advising, consulting, and cooperating with the cities and towns and other agencies of the state, federal government, interstate agencies, and other affected agencies or groups in matters relating to air quality;

VI. Encouraging local units to promote cooperation by the people, political subdivisions, industries, and others in preventing and controlling air pollution in the state;

VI-a. Encouraging the recycling of waste oil by allowing qualified marketers to sell, and qualified facilities to burn, a mixture that consists of at least 90 percent virgin no. 6 oil and the remainder complying with the used fuel oil specifications in 40 CFR, section 279.11, table 1;

VII. Entering at all reasonable times in or upon any private or public property, except private residences, for the purpose of inspecting or investigating any condition which is believed to be either an air pollution source or in violation of any of the rules or orders promulgated hereunder. Any information, other than emission data, relating to secret processes or methods of manufacture or production obtained in the course of such inspection or investigation shall not be disclosed by the commissioner without permission of the person whose source is inspected or investigated;

VIII. Accepting, receiving, and administering grants or other funds or gifts for the purpose of carrying out any of the functions of this chapter, including such monies given under any federal law to the state for air quality control activities, surveys, or programs;

IX. Consulting the air resources council established by RSA 21-O:11 on the policies and plans for the control and prevention of air pollution;

X. Exercising all incidental powers necessary to carry out the purposes of this chapter;

XI. Conducting emission tests and requiring owners or operators of stationary sources to install, maintain, and use emission monitoring devices and to make periodic reports to the commissioner on the nature and amounts of emissions from such stationary sources. The commissioner shall have the authority to make such data available to the public and as correlated with any applicable emission standards;

XII. Carrying out a program of inspection and testing of all modes of transportation, to enforce compliance with applicable emission standards when necessary and practicable and to control or limit the operation of motor vehicular and other modes of transportation when in the opinion of the commissioner such modes of transportation are producing or pose an imminent danger of producing levels of air pollutants that will result in a violation of an ambient air quality standard, or that will result in a significant deterioration, as defined in applicable federal regulations, of existing air quality in an area classified as a ""clean air" area by state or federal regulations;

XIII. Coordinating and regulating the air pollution control programs of political subdivisions of the state and entering agreements with said subdivisions to plan or implement programs for the control and abatement of air pollution;

XIV. Establishing and operating a statewide system under which permits shall be required for the construction, installation, operation or material modification of air pollution devices and sources, which system shall be established pursuant to RSA 125-C:11 and the sections which follow. The authority vested in the commissioner by this section shall include the power to delay or prevent any construction, modification or operation of said air pollution sources and modifications which, in the opinion of the commissioner, would cause the ambient air pollution level in the locality of such construction, modification or operation to exceed limits for ambient concentrations established by the New Hampshire state implementation plan adopted pursuant to the Clean Air Act as amended, or which construction, modification or operation would, in the opinion of the commissioner, violate any provision of any land use plan established by the New Hampshire state implementation plan;

XIV-a. Establishing fuel quality standards and testing requirements for biomass other than round wood and wood chips derived from round wood or waste wood such as limbs, branches, brush, slash, bark, stumps, sawdust, saw mill trimmings, clean pallets, and untreated wood scraps from furniture and other manufacture and eligible biomass fuel related to the combustion of such materials at stationary sources. The commissioner may establish such standards as necessary to maintain statewide compliance with Clean Air Act standards and RSA 125-I.

XV. Implementing a program of prevention of significant deterioration of ambient air quality by establishing air quality increments limiting the maximum allowable increases in the amounts of air pollutants provided such increments are not less stringent than those specified in the Clean Air Act and amendments thereto, and in regulations promulgated thereunder;

XVI. Establishing an air quality monitoring equipment replacement program to provide for sufficient annual replacement to meet federal Environmental Protection Agency guidelines and to assure the reliability and accuracy of the network equipment.

XVII. Implementing a program to control the emissions of air contaminants from consumer products for purposes of RSA 485:16-c, by establishing limits on the manufacture, use, or sale of such products, provided that such limits are not less stringent than those established under the Clean Air Act and amendments thereto, and in regulations promulgated under the Clean Air Act.

Source. 1979, 359:2. 1981, 332:3. 1986, 202:6, I(h), 8, 10. 1988, 277:1. 1995, 192:1. 1996, 228:104. 2001, 293:6, eff. July 17, 2001. 2008, 113:4, eff. Aug. 2, 2008.

Section 125-C:6-a

125-C:6-a Enhanced Environmental Performance Agreements. –

I. It is the purpose of this section to create a voluntary pilot program by which the commissioner of environmental services may enter into enhanced environmental performance agreements (EEPAs) with persons regulated under this chapter to implement innovative environmental measures not otherwise recognized or allowed under existing laws and rules of this state, if those measures achieve emissions reductions or reductions in discharges or wastes which equal or exceed those required under applicable statutes and rules, and to test innovative strategies for achieving enhanced environmental results. Approaches embodied in EEPAs should typically represent, favor, or promote pollution prevention, source reduction, environmental innovation, and transferability to other applicable entities, without increasing the overall level of pollution emitted directly or indirectly to the air, water, and land.

II. After notice and opportunity for public comment and hearing, the commissioner may enter into enhanced environmental performance agreements with any person regulated under any or all of RSA 125-C, RSA 125-D, RSA 125-I, or RSA 125-J to implement innovative environmental measures that relate to provisions of these chapters, even if one or more of the terms of such an agreement would be inconsistent with an otherwise applicable statute or rule of this state. Participation in this program is limited to those persons who have submitted an enhanced environmental performance agreement that is acceptable to the commissioner. A decision by the commissioner to not enter into an agreement with any person is not appealable.

III. An enhanced environmental performance agreement shall operate in lieu of existing permits identified in the agreement. Any environmental statute, regulation, or condition in an existing permit that differs from a term or condition in an agreement shall cease to apply from the effective date of an initial or renewed agreement until the agreement is terminated or expires.

IV. Persons applying to the commissioner for enhanced environmental performance agreements shall, at a minimum:

(a) Submit a description of how the proposal is consistent with the purpose of this section and federal guidelines, and a comprehensive description of the proposed EEPA which includes the nature of the facility, the operations which will be affected, how such operations will be altered to achieve superior emissions reductions, and the extent of emissions reduction anticipated.

(b) Include in EEPA proposals the following, without limitation:

(1) Identification of all state and federal statutes, rules and regulations applicable to the source.

(2) Identification of all statutes, rules and regulations that are inconsistent with one or more terms of the proposed agreement.

(3) A statement describing how the proposed agreement will achieve the purposes of this section.

(4) A statement describing the implementation of the proposed agreement, including a list of steps and schedule. Implementation of the proposed agreement shall not increase overall worker safety risks or create undue risk burdens on others.

(5) Identification of those members of the general public, representatives of local communities, environmental groups, and other appropriate parties who have participated in the development of the proposed agreement or who have an interest in the agreement.

(6) Identification of how the applicant will demonstrate ongoing satisfaction of the requirements of the agreement, including but not limited to, mechanisms for performance assurance and the type of performance guarantees to be provided, which guarantees shall be directly related to the complexity of, and risk associated with, the proposal.

(7) A description of and plan for public participation in the EEPA.

(8) A schedule for review by the commissioner of the performance of the proposed EEPA.

(9) Provisions for voluntary and involuntary termination of the agreement.

V. Without limiting the commissioner's authority under this section to specify additional criteria, the commissioner may adopt rules, under RSA 541-A, specifying criteria for acceptance of proposed enhanced environmental performance agreements.

VI. In the event of deficient performance of any term or condition in the agreement, the commissioner may, with written notice, terminate any agreement, and the participant shall then be subject to enforcement under the applicable chapter. The commissioner's decision to terminate an agreement is not appealable. If an agreement is terminated, the participant shall have 30 days to apply for any necessary permits concerning operations that were in effect during the course of the agreement.

VII. Nothing in this section shall limit the authority or the ability of the attorney general to initiate enforcement action against a person for violation of any laws of this state or rules adopted under such laws, except that an enhanced environmental performance agreement shall be deemed to be a permit to engage in activities authorized under the agreement.

VIII. Nothing in this section shall reduce, eliminate, or in any way affect any fees that a participant in this program may be required to pay under any federal or state law. Applicants for participation in the enhanced environmental performance agreements program shall pay all costs associated with public notice and hearings.

Source. 1996, 230:1. 1998, 229:2, eff. Aug. 23, 1998.

Section 125-C:7

125-C:7 Director. – [Repealed 1986, 202:29, IV, eff. Jan. 2, 1987.]

Section 125-C:8

125-C:8 Administration of Chapter; Delegation of Duties. – The commissioner shall be responsible for the implementation of this chapter and any rule adopted hereunder and may delegate to a subordinate or subordinates any and all duties vested in him, except rulemaking authority.

Source. 1979, 359:2. 1986, 202:11. 1996, 228:104, eff. July 1, 1996.

Section 125-C:9

125-C:9 Authority of the Commissioner in Cases of Emergency. – Whenever the commissioner finds that an air pollution emergency exists requiring immediate action to protect the public health, welfare, or safety, he may with consent of the governor and council issue an order reciting the existence of such an emergency and requiring that such action be taken as he deems necessary to meet the emergency. Such order shall be effective immediately. Any person to whom such an order is directed shall comply therewith. The commissioner shall rescind or abate such order as soon as the emergency ceases to exist.

Source. 1979, 359:2. 1996, 228:104, eff. July 1, 1996.

Section 125-C:10

125-C:10 Devices Contributing to Air Pollution. –

I. No person shall install, construct, operate, or modify any device or non-Title V source which contributes to air pollution except as prescribed by this chapter.

II. No person shall construct, operate or modify an affected source which contributes to air pollution except as prescribed by this chapter.

Source. 1979, 359:2. 1993, 329:4. 1996, 278:4, eff. Aug. 9, 1996.

Section 125-C:10-a

125-C:10-a Municipal Waste Combustion Units. – Any municipal waste combustor, as defined in RSA 125-M:2, XI, with a design capacity of at least 35 tons per day but no more than 250 tons per day of municipal solid waste, as defined in RSA 125-M:2, X, shall be limited to the following levels of emissions, unless otherwise provided for by a more stringent federal regulation, or by other state statute:

I. Particulate matter: 27 milligrams/dry standard cubic meter, corrected to 7 percent oxygen, 3-run average (run duration specified in test method).

II. Opacity: 10 percent (6-minute average), 30 6-minute averages.

III. Cadmium: 0.040 milligrams/dry standard cubic meter, corrected to 7 percent oxygen, 3-run average (run duration specified in test method).

IV. Lead: 0.44 milligrams/dry standard cubic meter, corrected to 7 percent oxygen, 3-run average (run duration specified in test method).

V. Mercury: 0.028 milligrams/dry standard cubic meter, corrected to 7 percent oxygen, or 85 percent control efficiency, 3-run average (run duration specified in test method).

VI. Sulfur dioxide: 29 parts per million by volume, or 25 percent of the potential sulfur dioxide emission concentration, corrected to 7 percent oxygen (dry basis), monthly block geometric average concentration or percent reduction.

VII. Hydrogen chloride: 29 parts per million by volume, or 5 percent of the potential hydrogen chloride emission concentration, corrected to 7 percent oxygen (dry basis), 3-run average (minimum run duration is 1 hour).

VIII. Dioxins/furans: 60 nanograms/dry standard cubic meter (total mass), corrected to 7 percent oxygen, where an electrostatic precipitator- based emission control system is employed; or 30 nanograms/dry standard cubic meter (total mass) corrected to 7 percent oxygen, where an electrostatic precipitator-based emission control system is not employed, 3-run average (minimum run duration is 4 hours).

Source. 2005, 72:1, eff. Jan. 1, 2006.

Section 125-C:10-b

125-C:10-b Best Available Control Technology Required. –

I. For the purposes of this section:

(a) ""Best available control technology" means an emission limitation based on the maximum degree of reduction for each air contaminant that would be emitted from any device that the department, on a case-by-case basis, taking into account energy, environmental, public health, and economic impacts and other costs, determines is achievable for such device through application of production processes or available equipment, methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such air contaminant.

(b) ""Exempt fuel" means coal, natural gas, landfill gas, digester or bio gas, untreated wood, virgin petroleum products, or any mixture thereof.

II. Except as provided in paragraph VII, the construction, installation, operation, or material modification of any device located at an affected source that will combust any material shall be prohibited without first applying for and obtaining a permit from the department that establishes emission limitations for such device based on best available control technology for controlling any particulate matter, mercury, or dioxin emissions from such device. Any material to be combusted in such device that is not an exempt fuel shall be certified as complying with standards established by the department. As part of the application for a permit, the affected source shall demonstrate that such standards and certification shall be complied with during facility operation. The permit shall contain inspection, testing, and reporting requirements to ensure such standards are met. The permit shall establish procedures for sampling and testing appropriate to the material to be combusted using US EPA SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, and applicable American Society for Testing and Materials sampling methods or alternate sampling and testing methods approved by the department.

III. If stack testing results show that emissions from a device are less than but within 10 percent of the emission limitation for a specific air contaminant established under paragraph II for the device, the affected source shall install a department approved continuous emission monitor (CEM) for that air contaminant. If a department approved CEM is not available for that air contaminant, the affected source shall submit a plan, including monitoring and stack testing requirements, for ensuring that the emissions limitation for that air contaminant is not exceeded until such time as a department approved CEM for that air contaminant becomes available. Once a department approved CEM is available, the affected source shall install that CEM within 24 months of department approval of the CEM.

IV. Once the department has established an emission limitation for one or more air contaminants under paragraph II for a device based on best available control technology, no further best available control technology determination for the emission of such air contaminant or air contaminants from such device shall be required for such period of time as specified in rules of the department, unless there is a material modification of the device.

V. Any determination by the department pursuant to paragraph II, shall be subject to the following:

(a) In no event shall application of best available control technology result in:

(1) Emission of any air contaminant that would exceed the emissions allowed by any applicable standard under RSA 125-C or RSA 125-I or rules adopted pursuant to either chapter; and

(2) Emission of any air contaminant specified in paragraph II in an amount disproportionate to the emissions of such air contaminant from other similar air pollution control devices for that air contaminant at facilities using similar combustion technology and similar fuels.

(b) If the department determines that a device emits more than one of the air contaminants specified in paragraph II, or that the affected source has more than one device that emits such air contaminants, the department shall determine best available control technology emission limitations for all such devices and all such air contaminants emitted.

VI. If, prior to the effective date of this section, the department made under other authority a best available control technology determination for any air contaminant specified in paragraph II for any existing device and established in a permit issued pursuant to this chapter an emission limitation for such air contaminant, then no determination of best available control technology pursuant to paragraph II for such air contaminant from such device shall be required for such period of time as specified in rules of the department, unless there is a material modification of the device.

VII. This section shall not apply to:

(a) A municipal waste combustor that is subject to RSA 125-M;

(b) Chemical recovery combustion sources at pulp and paper mills subject to 40 CFR 63, Subpart MM;

(c) A device at an affected source that combusts material of which at least 90 percent by weight is exempt fuel;

(d) An affected source that is within a listed source category and subject to a performance standard or emission guidelines established by the United States Environmental Protection Agency pursuant to either section 111 or section 112 or section 129 of the Clean Air Act, provided that these standards and guidelines are at least as stringent as those achieved by applying best available control technology as specified under paragraph II;

(e) A device at an affected source that, on the effective date of this section, routinely combusts any material other than a material specified in subparagraph (c) under a permit issued by the department, unless there is later a material modification of such device; or

(f) A device at an affected source with emissions of particulate matter, mercury, or dioxin below threshold levels established by rules of the department.

Source. 2005, 173:4, eff. June 29, 2005.

Section 125-C:10-c

[RSA 125-C:10-c effective until January 1, 2011; see also 125-C:10-c set out below.]

125-C:10-c Combustion Ban. –

Notwithstanding any provision of law to the contrary, no person shall combust the wood component of construction and demolition debris, as defined in RSA 149-M:4, IV-a, or any mixture or derivation from said component. This section shall not apply to the incidental combustion of such materials by any municipal waste combustor, as defined in RSA 125-M:2, XI, which was subject to regulation by this chapter or RSA 149-M and which was in operation on January 1, 2006, or by any municipal incinerator that is permitted by the department and was in operation on January 1, 2006. This section shall not apply to the incidental combustion, under the supervision of a solid waste facility operator, of untreated wood at any municipal transfer station subject to regulation under RSA 149-M.

Source. 2007, 128:1, eff. Jan. 1, 2008.

Section 125-C:10-c

[RSA 125-C:10-c effective January 1, 2011; see also RSA 125-C:10-c set out above.]

125-C:10-c Combustion Ban. –

Notwithstanding any provision of law to the contrary, no person shall combust the wood component of construction and demolition debris, as defined in RSA 149-M:4, IV-a, or any mixture or derivation from said component. This section shall not apply to the incidental combustion of such materials by any municipal waste combustor, as defined in RSA 125-M:2, XI, which was subject to regulation by this chapter or RSA 149-M and which was in operation on January 1, 2006, or by any municipal incinerator that is permitted by the department and was in operation on January 1, 2006.

Source. 2007, 128:1, eff. Jan. 1, 2008; 128:2, eff. Jan. 1, 2011.

Section 125-C:11

125-C:11 Permit Required. –

I. The construction, installation, operation, or material modification of any device or non-Title V source as defined under RSA 125-C:2, and as further defined by rules adopted by the commissioner shall be prohibited unless the source possesses a temporary permit or final permit issued by the commissioner. The commissioner may by rule exempt certain devices or non-Title V sources from the requirements of this section.

I-a. The operation of an affected source shall be prohibited unless the affected source possesses and complies with a permit to operate issued by the commissioner in accordance with the requirements of the Clean Air Act. The term of the permit to operate shall not exceed 5 years.

II. A temporary permit, which may contain conditions, shall be required prior to commencement of construction or installation of any new or modified device or non-Title V source, and shall be in effect until a final permit is issued or until sooner revoked by the commissioner. Such permit shall contain the emission limits the device or non-Title V source is required to meet, and shall be issued by the commissioner upon a finding that the device or non-Title V source will meet such limits and will not result in a violation of any air quality standard or regulation in force under this chapter.

III. A final permit, which may contain conditions, shall be issued with respect to a device or non-Title V source for which a temporary permit is in effect, upon a finding by the commissioner, following operational testing, where required, that the device or non-Title V source meets the applicable emission limits and that its operation will not result in a violation of any air quality standard or regulation in force under this chapter.

III-a. [Repealed.]

IV. The applicant shall be required to conduct preconstruction or premodification review procedures prior to commencement of construction of any new major stationary source, device, or modification to any existing major stationary source or device. Such procedures shall be sufficient to allow the commissioner to make determinations that the proposed construction or modification will not cause or contribute to a failure to attain or maintain any ambient air quality standard, significant deterioration of air quality, or a violation of any applicable emission limitation or standard of performance. Prior to commencement of construction or modification, the applicant shall submit the required information to the commissioner. Such preconstruction and premodification review requirements shall be no less stringent than, and shall require that no permit shall be issued for a source unless such source meets all the requirements for review and for obtaining a permit prescribed in the Clean Air Act.

V. The applicant for a permit to operate shall be required to conduct preconstruction or premodification review procedures prior to commencement of construction of any affected source. Such procedures shall be sufficient to allow the commissioner to make determinations that the proposed construction or modification will not cause or contribute to a failure to attain or maintain any ambient air quality standard, significant deterioration of air quality, or a violation of any applicable emission limitation or standard of performance. The applicant shall submit the required information to the commissioner prior to the commencement of construction or modification. Such preconstruction review and premodification review requirements shall be no less stringent than those prescribed in the Clean Air Act, 42 U.S.C. section 7401 et seq., as amended.

Source. 1979, 359:2. 1981, 332:4. 1986, 202:6, I(h). 1993, 329:5-8. 1995, 68:1, 4. 1996, 228:104, eff. July 1, 1996; 278:11, 12, eff. Aug. 9, 1996.

Section 125-C:12

125-C:12 Administrative Requirements. –

I. Applications for permits shall be upon such forms, and shall include such information, as the commissioner requires under rules adopted pursuant to RSA 541-A in order to determine the nature of the air pollution potential for such device or non-Title V source.

II. The commissioner shall act upon a permit application within a reasonable period of time. Prior to such action, the commissioner shall provide notice of the application by publication in at least one newspaper of general circulation. The commissioner shall also provide an opportunity for a hearing to interested persons. The requirement of public notice and hearing shall not apply to such devices or sources that will have, in the opinion of the commissioner, an insignificant effect on air quality. The commissioner may adopt rules relative to the requirements of public notice and hearing for such devices or sources.

III. Any person aggrieved by the decision of the commissioner granting or denying a permit application may within 10 days of the decision file an appeal with the air resources council. The air resources council shall hold a hearing on any such appeal promptly, and shall thereafter issue a decision upholding, modifying or abrogating the commissioner's decision.

IV. As a condition of any permit required, the commissioner may require payment of a fee to cover the reasonable costs of reviewing and acting upon the application for a permit and of implementing or enforcing the terms and conditions of a permit. The applicant shall pay any cost or expense associated with public notices or notifications in the permit process. The commissioner shall adopt rules relative to a fee schedule for applicants and the collection of fees under the schedule. All fees and monetary grants, gifts, donations, or interest generated by these funds shall be deposited with the state treasurer in a special nonlapsing fund to be known as the air resources fund and shall be continually appropriated to the department for the administration of this chapter.

V. As a condition of any permit to operate under RSA 125-C:11, I-a, the commissioner may require payment of a fee to cover the reasonable costs of reviewing and acting upon the application for a permit to operate, permit renewal, and permit modification of an affected source, and of implementing or enforcing the terms and conditions of an affected source permit. The applicant shall pay any cost or expense associated with public notices or notifications in the permit process. The commissioner shall adopt rules relative to a fee schedule for applicants and the collection of fees under the schedule. Funds collected by the commissioner under this paragraph from permit fees shall be deposited in the air resources fund, shall be accounted for separately, and shall be used by the commissioner for the establishment and operation of a statewide system of permitting for the construction, operation, or modification of any new or existing affected source.

Source. 1979, 359:2. 1981, 332:5. 1986, 202:6, I(h). 1991, 289:1. 1993, 329:9. 1995, 68:2. 1996, 228:104, 107, eff. July 1, 1996; 278:13, eff. Aug. 9, 1996.

Section 125-C:13

125-C:13 Criteria for Denial; Suspension or Revocation; Modification. –
I. The commissioner shall deny an application for a temporary or final permit if, on the basis of evidence available to the commissioner, the commissioner determines:
(a) That the device or non-Title V source for which the permit is sought will result in a violation of any standard or rule in force under this chapter; or
(b) That the device or non-Title V source will contribute disproportionately to pollution of the air in comparison with other similar sources able to perform the same function that are currently available; or
(c) That the device or non-Title V source is located in a ""clean air" area designated by state or federal rules or regulations and will or is reasonably likely to cause significant deterioration of the existing air quality in a part of the area.
II. The commissioner may suspend or revoke any temporary or final permit issued hereunder if, following a hearing, the commissioner determines:
(a) That the permit holder has committed a violation of this chapter or any rule, order or permit conditions in force and applicable to it; or
(b) That emissions from the device or non-Title V source to which the permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.
III. The commissioner may order modification of any source of air pollution holding a valid permit issued under this chapter in the event that the commissioner determines, following a hearing:
(a) That the device or non-Title V source to which the permit applies fails to meet existing emission limits established by state or federal rule or regulation;
(b) That the device or non-Title V source is resulting or is reasonably likely to result in a violation of an air quality standard in force.
IV. The commissioner may terminate, modify, revoke, or reissue for cause any permit to operate issued to an affected source prior to expiration of such permit consistent with the requirements of the Clean Air Act.

Source. 1979, 359:2. 1993, 329:10, 11. 1995, 68:3. 1996, 228:104, eff. July 1, 1996; 278:14, eff. Aug. 9, 1996.

Section 125-C:14

125-C:14 Rehearings and Appeals. – Administrative appeals from decisions of the commissioner made under the provisions of this chapter shall be heard by the air resources council under RSA 21-O:11, IV.

Source. 1979, 359:2. 1981, 332:6, 7. 1986, 202:12. 1996, 228:104, eff. July 1, 1996.

Section 125-C:15

125-C:15 Enforcement. –

I. Whenever the commissioner or the commissioner's authorized representative finds that any device, non-Title V source, affected source of air pollution, or any other source of air pollution has resulted in a violation of any of the provisions of this chapter or any rules in force hereunder, or any condition in a permit issued under this chapter, the commissioner shall issue a notice of violation and, where appropriate, an order of abatement establishing a compliance schedule with which the device, non-Title V source, affected source, or any other source shall comply. Any order of abatement shall become final and enforceable by the commissioner within 30 days of its issuance unless an appeal is filed with the air resources council before the expiration of said 30-day period. The council shall hold a hearing on any such appeal promptly, and shall thereafter issue a decision upholding, modifying or abrogating the commissioner's order of abatement or any part thereof. The council's decision shall become final 10 days after it is issued. Upon a finding by the commissioner that there is an imminent and substantial endangerment to the public health or welfare or the environment, the commissioner shall issue an order of abatement requiring immediate compliance and said order shall be final and enforceable upon issuance, but may be appealed to the council within 30 days of its issuance, and the council may, after hearing, uphold, modify, or abrogate said order.

I-a. Whenever the commissioner or his authorized representative finds that a gasoline dispensing facility subject to Stage II vapor recovery system requirements has resulted in a violation of any provisions of this chapter or the rules in force hereunder, the commissioner or authorized representative shall issue a stop use order and compliance schedule with which the gasoline dispensing facility shall comply. Any stop use order shall become final and enforceable upon issuance, but may be appealed to the council within 10 days of its issuance and the council, after hearing, may uphold, modify, or abrogate such order.

I-b. The commissioner of the department of environmental services, after notice and hearing pursuant to RSA 541-A, may impose an administrative fine not to exceed $2,000 for each offense upon any person who violates any provision of this chapter, any rule adopted pursuant to this chapter, or any permit, compliance schedule, stop use order, or order of abatement, issued pursuant to this chapter; or upon any person who makes or certifies a material false statement relative to any document or information which is required to be submitted to the department pursuant to this chapter or any rule adopted pursuant to this chapter. Rehearings and appeals from a decision of the commissioner under this paragraph shall be in accordance with RSA 541. Any administrative fine imposed under this paragraph shall not preclude the imposition of further penalties under this chapter. The proceeds of administrative fines imposed pursuant to this paragraph shall be deposited in the general fund.

(a) Notice and hearing prior to the imposition of an administrative fine shall be in accordance with RSA 541-A and procedural rules adopted by the commissioner pursuant to RSA 541-A:16.

(b) The commissioner shall determine fines based on the following:

(1) For a minor deviation from a requirement causing minor potential for harm, the fine shall be not less than $100 and not more than $1,000.

(2) For a minor deviation from a requirement causing moderate potential for harm, the fine shall be not less than $601 and not more than $1,250.

(3) For a minor deviation from a requirement causing major potential for harm, the fine shall be not less than $851 and not more than $1,500.

(4) For a moderate deviation from a requirement causing minor potential for harm, the fine shall be not less than $601 and not more than $1,250.

(5) For a moderate deviation from a requirement causing moderate potential for harm, the fine shall be not less than $851 and not more than $1,500.

(6) For a moderate deviation from a requirement causing major potential for harm, the fine shall be not less than $1,251 and not more than $1,750.

(7) For a major deviation from a requirement causing minor potential for harm, the fine shall be not less than $851 and not more than $1,500.

(8) For a major deviation from a requirement causing moderate potential for harm, the fine shall be not less than $1,251 and not more than $1,750.

(9) For a major deviation from a requirement causing major potential for harm, the fine shall be not less than $1,501 and not more than $2,000.

(c) The commissioner may assess an additional fine for repeat violations.

II. Any violation of the provisions of this chapter, or of any rule adopted or order issued under it, or of any condition in a permit issued under it, shall be subject to enforcement by injunction, including mandatory injunction, issued by the superior court upon application of the attorney general. Any such violation shall also be subject to a civil forfeiture to the state of not more than $25,000 for each violation, and for each day of a continuing violation.

III. Any person who violates any of the provisions of this chapter, or any rule adopted or order issued under this chapter, or any condition of a permit issued under this chapter shall be guilty of a misdemeanor if a natural person, or guilty of a felony if any other person.

IV. Notwithstanding RSA 651:2, any person may, in addition to any sentence of imprisonment, probation, or conditional discharge, be fined not more than $25,000 if found guilty of any violation pursuant to RSA 125-C:15, III. Each day of violation shall constitute a separate offense.

Source. 1979, 359:2. 1981, 332:8. 1993, 329:12. 1996, 228:104; 247:11; 278:15. 1998, 146:1, 2, eff. June 8, 1998.

Section 125-C:16

125-C:16 Variances. –

I. Upon application, and after a hearing, the commissioner may suspend the enforcement of the whole or any part of this chapter or of any rule adopted hereunder in the case of any person who shall show that the enforcement thereof would produce serious economic hardship on such person without equal or greater benefits to the public.

II. In determining under what conditions and to what extent the variance may be granted, the commissioner shall give due recognition to the progress which the person requesting such variance shall have made in eliminating or preventing air pollution; the character and degree of injury to, or interference with, the health and physical property of the people; and the social and economic value of the source of air pollution. In such cases, the commissioner shall consider the reasonableness of granting a variance conditioned on the person's effecting a partial abatement of pollution or a progressive abatement thereof or such other circumstances as the commissioner may deem reasonable. No variance shall be granted to any person applying therefor who is causing air pollution which creates a danger to public health, welfare or safety.

III. Any variance granted hereunder shall be granted for such period of time, not exceeding one year, as the commissioner shall specify. No variance shall be construed to relieve the person receiving it from any liability imposed by law for the commission or maintenance of a nuisance.

Source. 1979, 359:2. 1986, 202:6, I(h). 1996, 228:104, eff. July 1, 1996.

Section 125-C:17

125-C:17 Penalty. – [Repealed 1993, 329:14, eff. June 24, 1993.]

Section 125-C:18

125-C:18 Existing Remedies Unimpaired. – No existing civil or criminal remedy for any wrongful action which is a violation of any code or rule adopted hereunder shall be excluded or impaired by this chapter.

Source. 1979, 359:2, eff. July 1, 1979.

Section 125-C:19

125-C:19 Protection of Powers. – The powers and functions vested in the commissioner under the provisions of this chapter shall not be construed to affect in any manner the powers, duties and functions vested in the department of health and human services under any other provision of law.

Source. 1979, 359:2. 1983, 291:1, I. 1986, 202:6, I(h). 1995, 310:181. 1996, 228:104, eff. July 1, 1996.

Section 125-C:19-a

125-C:19-a Recovery of Public Utility Expenditures. – All costs and expenses directly incurred by electric generating facilities for pollution reductions that are a component of, or are required in connection with, any vehicle inspection and maintenance program adopted by the state of New Hampshire and approved by the federal Environmental Protection Agency, or substitute for such program, shall be recoverable to the same extent and subject to the same conditions as any environmental expenditure mandated by law, and shall be recoverable through the fuel and purchased power adjustment clause or any succeeding cost recovery mechanism.

Source. 1998, 207:1, eff. June 18, 1998.

Section 125-C:20

125-C:20 Exemption; Steam Locomotives and Engines. – The provisions of this chapter shall not apply to any steam locomotives and engines or replacements thereof used in connection with the operation of a railroad or railway which were in operation or on order prior to January 1, 1973, and are located entirely within the state; provided that this exemption shall not apply to any stationary steam engine.

Source. 1979, 359:2, eff. July 1, 1979.

Section 125-C:21

125-C:21 Severability. – If any provision of this chapter or the application thereof to any person or circumstance is held invalid, the invalidity does not affect other provisions or applications of the chapter which can be given effect without the invalid provision or application; and, to this end, the provisions of this chapter are severable.

Source. 1981, 332:9, eff. Aug. 16, 1981.