ATTACHMENT O

Development of MANE-VU Mobile Source Projection Inventories for SMOKE/MOBILE6 Application

Technical Memorandum

Development of MANE-VU Mobile Source Projection Inventories for SMOKE/MOBILE6 Application

June 2006, NESCAUM

I. Background

The MANE-VU Emissions Inventory workgroup chose to utilize in-house expertise to develop future year mobile source emission estimates for use in Ozone, $PM_{2.5}$, and Regional Haze SIP modeling. Jung-Hun Woo, NESCAUM, and Megan Schuster, MARAMA compiled all the information necessary to run Mobile6 with Sparse Matrix Operator Kernel Emissions (SMOKE) based on the state submitted data. The purpose of this document is to describe how member states and NESCAUM/MARAMA prepared the mobile source activity data (i.e. non-link based VMT & Speed), Mobile6 scenario input files, and accompanying files in SMOKE/MOBILE6 format in support of future year projection inventory development.

II. Procedure

2.1. Base year (Y2002) inventory file

The MANE-VU 2002 base year SMOKE/M6-ready mobile source files served as a starting point for projection inventory development; hence, the procedures employed for the development of these files are summarized here. E.H Pechan, a contractor for MANE-VU, compiled MANE-VU 2002 mobile source inventories. The onroad emissions inventory was compiled from data supplied by the MANE-VU State agencies in the form of onroad emissions input data or emissions inventories either directly to MANE-VU or to EPA through their CERR submittal. States provided information in one or more of the following ways: (1) an onroad emission inventory submittal to EPA, (2) MOBILE6 inputs and VMT data in National Mobile Inventory Model (NMIM) format to EPA, (3) portions of MOBILE6 inputs or full MOBILE6 input files and supporting files plus VMT to EPA, or (4) portions of MOBILE6 inputs or full MOBILE6 input files and supporting files plus VMT to MANE-VU. Different procedures were followed in developing the MANE-VU 2002 onroad emission inventory depending upon how the data were submitted. All States provided information on 2002 onroad activity in the form of vehicle miles traveled (VMT) estimates, although the level of detail of the VMT data varied by State. After integration of all these data, Pechan compiled onroad mobile source files in a SMOKE/Mobile6 ready format.

2.2. Preparing technical guidance to create SMOKE/Mobile6 ready information

As described above, States had the ability and experience to develop their mobile source inventory data in NMIM, stand-alone Mobile6, and emissions inventory format. They, however, were not familiar with procedures for integrating files and converting them into a model ready format. To assist the State workgroup in the creation of an inventory in (as close as possible to) the SMOKE/Mobile6–ready format, NESCAUM/MARAMA developed a technical guidance document (http://www.marama.org/visibility/Inventory%20Summary/FutureEmissionsInventory.htm). In the document, we also explained how State workgroup could download the year 2002 files (ftp.marama.org) and update them to create projection inventory files.

In the technical guidance, States were requested to supply NESCAUM and MARAMA with the data described below, under Required Data. States also had the option to supply NESCAUM and MARAMA with the information listed under Optional Data.

REQUIRED DATA:

1) SMOKE/IDA Activity File
    a. Go to MARAMA FTP site (above), click on Onroad/ Final Smoke Files/ MANEVU_2002_mbinv.txt
    b. Open the MANEVU_2002_mbinv.txt file
    c. Delete all data that is not your state's.
    d. Update file with new header and annual VMT by SCC for 2009
    e. Name file: state_2009_mbinv.txt
    f. Repeat steps 'b' through 'e' for years 2012 and 2018

2) MOBILE6 input scenario files
    a. Go to MARAMA ftp site, click on MANE-VU Onroad/ Final Smoke Files/ MANEVU_2002_SMOKE_M6_InputFiles_12032004.zip /m6_2002/month/statecounty.in
    b. Provide updated statecounty.in files for each month and year 2009, 2012 and 2018
    c. Use same naming convention as the 2002 files – statecounty.in

OPTIONAL DATA:

1) If a state wants to, they can update registration data to either 2004 or 2005
    a. Go to MARAMA FTP site - Onroad/ Final Smoke Files/MANEVU_2002_SMOKE_M6_ExternalFiles.zip
    b. As an example, open file 0900002.reg (or any files with extension .reg)
    c. There is a long header followed by the real data. Real data starts at the line called REG DIST. (See example file below).
    d. States should update the registration data by vehicle class and age for 2004 or 2005.
    e. If you update this data and change the name of the file, make sure the M6 input scenario file (required data from above) includes the correct file name for registration data (REG DIST).

2.3. States data submittal and compiling future inventory

As States submitted their projected mobile source files as listed above, NESCAUM started to integrate Y2018 files and convert them into regional (i.e. MANE-VU) files. The following subsections summarize the compilation process for activity input, scenario input files, external files and other SMOKE related files.

1) Activity input data (VMT/Speed)
   - All member states submitted VMT and speed data. There were minor issues in data formatting but nothing major.
   - DE and MA re-submit VMT file at October, 2005 (MA change 2002 VMT, too)
   - Merge update 2002 MBINV file, ptpro/ptref, scenario input files for CT and NJ
2) Scenario input files
   - VT used the same input file for all the counties. So, only 36 input files (i.e. 12months * 3 future years) were provided. VT set 050001 as a reference county (MCREF).
   - VT uses January as reference month for August processing. VT has confirm that they want to change reference month for Apr-Sep as July instead of January.
   - ME submitted all monthly data in a file. NESCAUM split it by month.
   - MA submitted only three input files (Avg Summer day, Typ Ozon day, Avg Winter day) which were submitted to PECHAN to develop base year input files. NESCAUM created *.in files by copying MANE-VU 2002 base-year *.in files, then change years into 2009/2012/2018 and the link to the new external files (LEV2CERT.D, LEV2EVAP.D, LEV2EXH.D).
   - CT submitted *.IN files on 9/22/2005. The "> I/M DESC" file path had been removed.
   - RI scenario input files have 044yyc.IN name convention that are supposed to be 044ccc.IN(yy stands for 2digit year and ccc stands for 3digit county FIPS). They are renamed and populated for 12months.
   - Some states(MD) put "REBUILT EFFECTS" after "SCENARIO RECORD" line. They were moved ahead of it.
   - PA put "ANTI-Tamp" records in external files that need to be in Scenario input files. NESCAUM wrote a Fortran code (pa_input_4_override.f) and a C-shell script(cp_antitamp_4_pa.csh) to put those records in scenario input files
   - NJ has 2012 year tag in 2009 scenario input files. NESCAUM put them back to 2009.
   - For 2002 scenario input files update (10/27/2006), CT puts 0.07 Rebuild effect, NJ didn't put any. So, I put 0.1 to NJ 2002 input files.
   - Putting future year rebuild effect is a modeling decision that needs to be a constant throughout the region. So NESCAUM didn't correct that in file compilation. Modelers' put 10% for the base year (2002) and 90% for the future years(2009/2012/2018). NYSDEC put 0.9 into year 2009 files and NESCAUM put 0.9 into year 2018 files before SMOKE/Mobile6 processing.
3) External files
   - VT uses some of NY state external files (e.g. NYLEV2.D, NYL2EXH.D, NYL2EVAP.D, and NYL2CERT.D)
   - RI didn't provide any future-specific external files. 2002 MANE-VU M6 external files were used

- MA and ME used the same named files which have identical contents to each other:
  LEV2CERT.D, LEV2EVAP.D, and LEV2EXH.D
- DE, PA, and NJ submitted the same named files which have identical contents to each other:
  NLEVNE.D
- DC file produce warnings (but not errors) from SMOKE/Mobile6 test run
  "User Supplied HC IM240 Cutpoint of 0.500 for year 1 and Vehicle Type 1 is Too Low and has been Reset to 0.80 g/mi." Consulted with DC and get a confirm that it's ok to use it as-is.

4) Other SMOKE related files

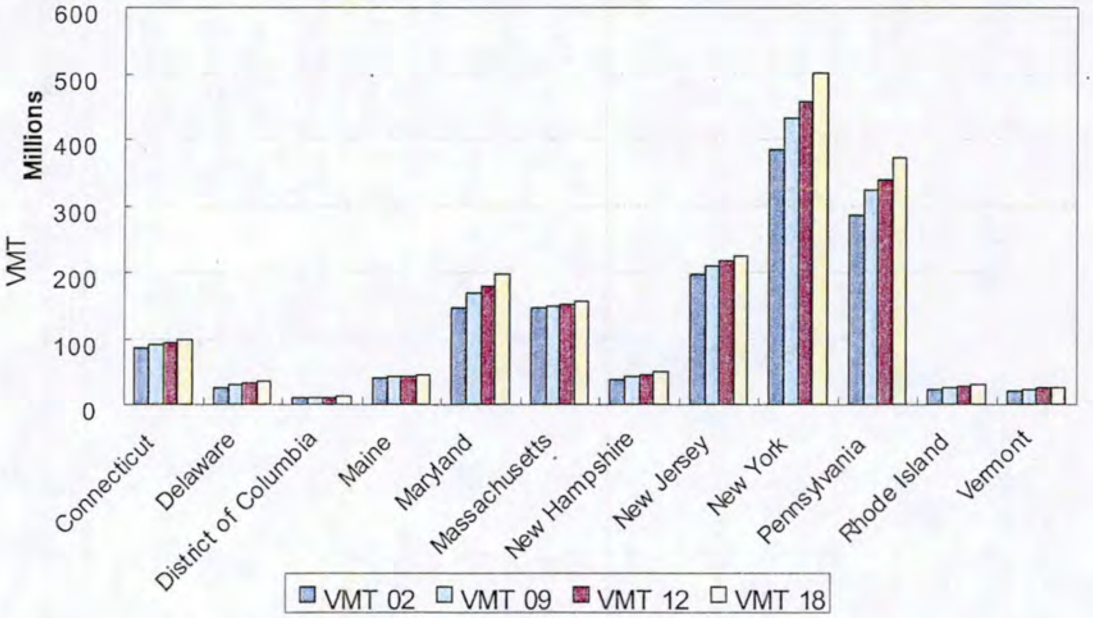
- MCREF/MVREF

  Update MANEVU_2002_mcref.txt for Maine because Penobscot county (23019) was not found from MAINE_pointerfile.xls. Tammy Gould @ Maine confirmed that Penobscot (019) has to be added where Piscataquis (021) is. Correct this problem on both MANEVU_2018_mcref.txt and MAINE_pointerfile.xls. MANEVU_2018_mvref.txt is updated by deleting non-ref counties in ME.
- MTPRO/MTREF

  Add CT and NJ's temporal profile/x-ref to 2018 MANEVU files

III. Sample model run

Even though NESCAUM had not run SMOKE/Mobile6 for any of the complete projection years, we ran a day worth of each year: 1) to test compatibility of compiled data with SMOKE/Mobile6 system and 2) to examine trends in submitted projection data. As seen in the Figure 1 and Figure 2, VMT increases 10~20% compared to the base year (i.e. year 2002) for the most of states whereas speed remains the same except for NY and PA.



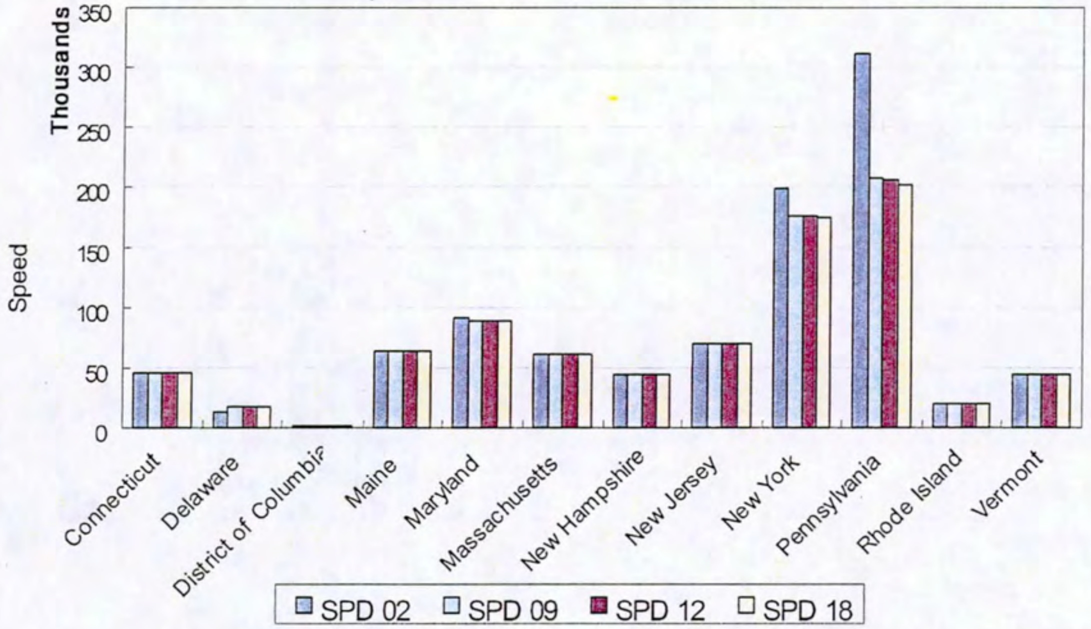
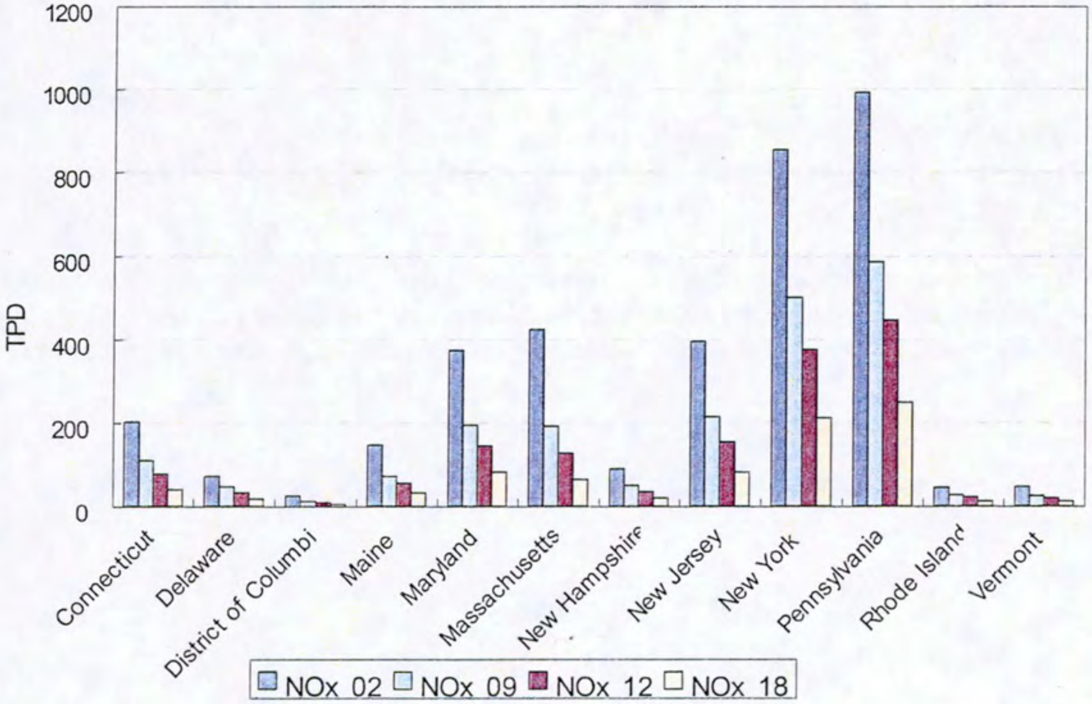


Figure 1. VMT(upper) and Speed (lower) for one day (August 1) of year 2002, 2009, 2012, and 2018



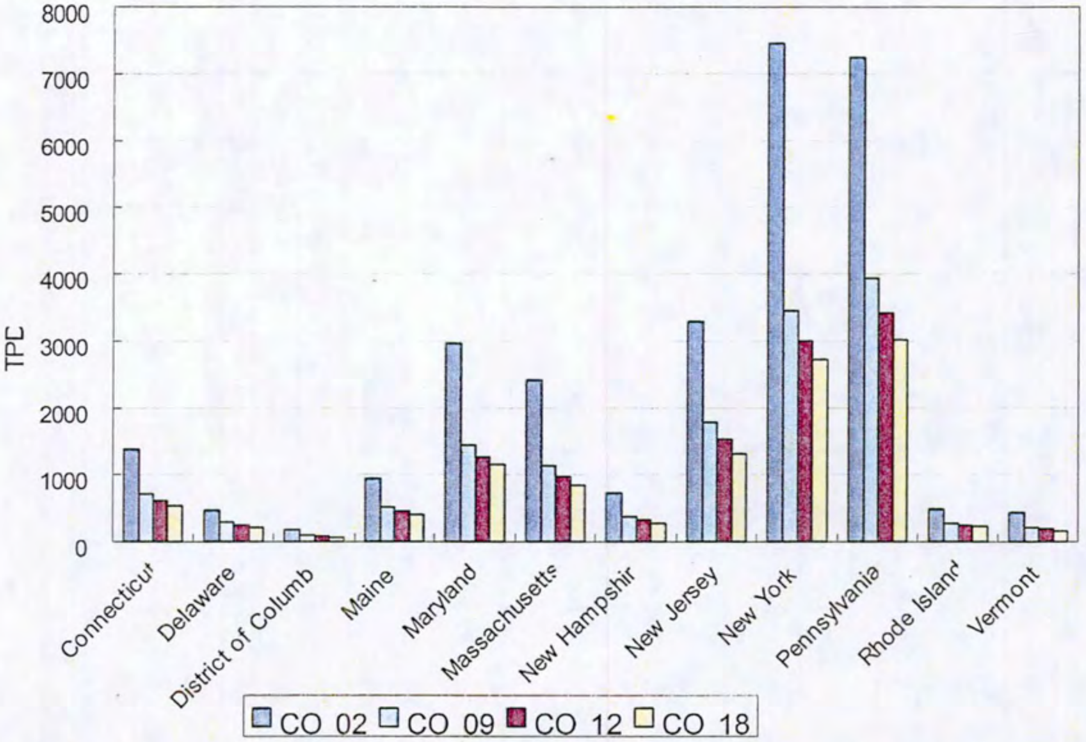


Figure 2. NOx(upper) and CO (lower) emissions for one day (August 1) of year 2002, 2009, 2012, and 2018

Despite VMT increases, NO_x and CO emissions decrease dramatically due to future-year control programs. Emissions decrease a bit more slowly after 2009 given fewer anticipated controls during post-2009 years.

NOx reductions seen from Figure 2 can be verified in the spatial (by county) NOx emission maps which were calculated using SMOKE/Mobile6 for August 1 of each year. As region wide emissions decreased by years, emissions from high emission areas (e.g. urban centers) decreased, as well.

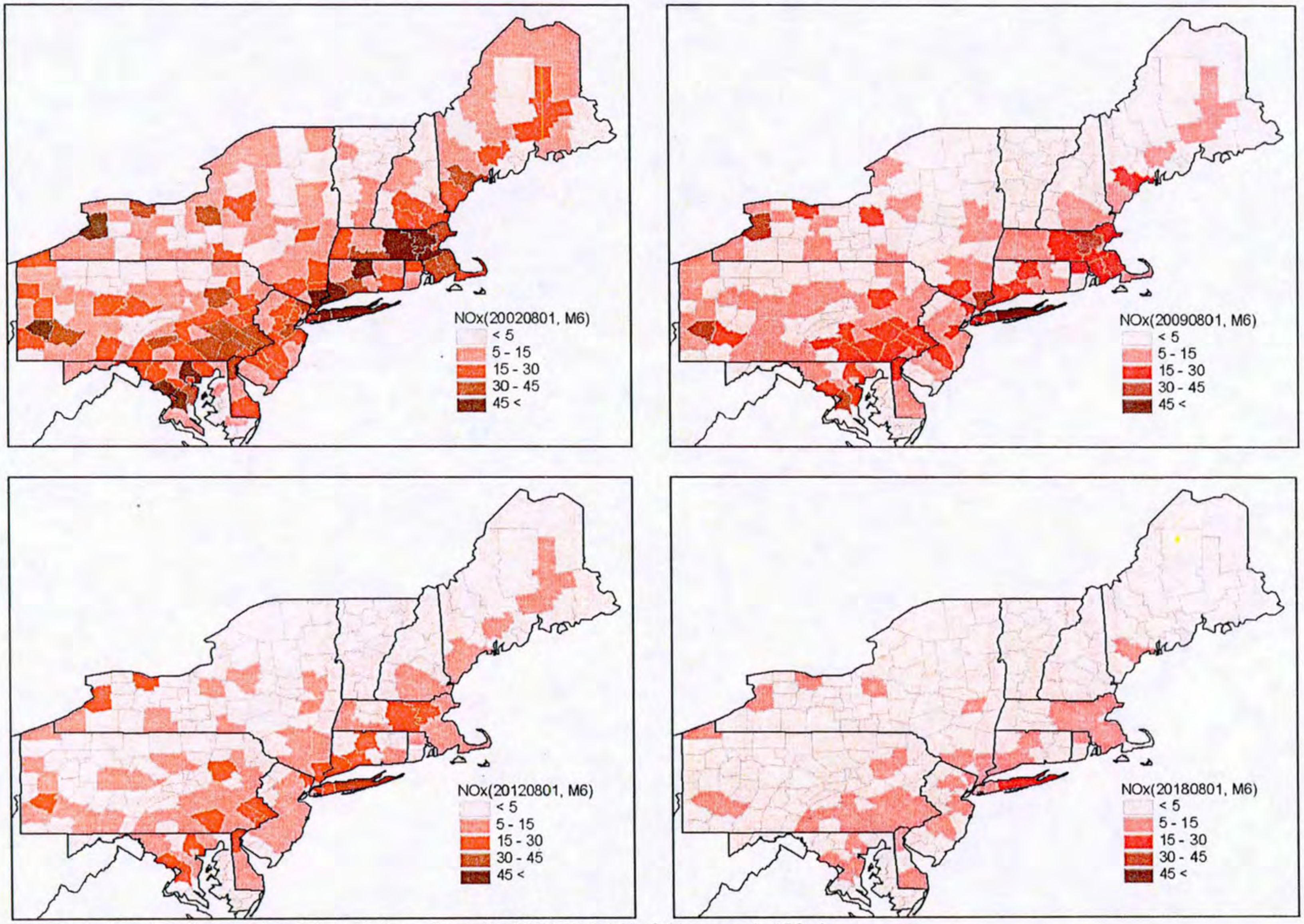


Figure 3. Spatial distribution of emissions from SMOKE/Mobile6 (August 1, NOx)

ATTACHMENT P

NYSDEC Technical Support Document TSD-1c

TSD-1c

Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations

Bureau of Air Quality Analysis and Research
Division of Air Resources
New York State Department of Environmental Conservation

September 19, 2006

1. Overview

All emissions processing for the revised 2002 OTC regional and urban 12 km base case simulations was performed with SMOKE2.1 compiled on a Red Hat 9.0 Linux operating system with the Portland group fortran compiler version 5.1. The emissions processing was performed on a month-by-month and RPO-by-RPO basis, i.e. SMOKE processing was performed for each month for each of the RPOs (MANE-VU, VISTAS, CENRAP, MRPO) individually as well as for Canada. For each month/RPO combination, a separate SMOKE ASSIGNS file was created, and the length of the episode in each of these ASSIGNS files was set to the entire month. Also, as discussed in Section 3, there was no difference between "episode-average" temperatures and "monthly-average" temperatures for the Mobile6 simulations that used the option of temperature averaging.

This document is structured as follows: A listing of all emission inventories is given in Section 2, organized by RPO and source category. Section 3 discusses the Mobile6 processing approach employed for the different RPOs, while Section 4 describes the processing of biogenic emissions with BEIS3.12. Finally, Sections 5 through7 describe the temporal allocation, speciation, and spatial allocation of the emissions inventories, respectively.

2. Emission Inventories

2.1 MANE-VU

Version 3 of the MANE_VU inventory was utilized to generate CMAQ-ready emissions. This emissions inventory data were obtained from the MANEVU archive in April 2006.

2.1.1 Area Sources

- Files: MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt and MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt prepared by PECHAN, downloaded from **ftp.marama.org** (username mane-vu, password exchange)
- Fugitive dust correction: This was applied as county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing

2.1.2 Nonroad Sources

- File: MANEVU_NRD2002_SMOKE_030306 prepared by PECHAN; downloaded from **ftp.marama.org** (username mane-vu, password exchange)

2.1.3 Mobile Sources

- VMT/Speed: MANEVU_2002_mbinv_02022006_addCT.txt prepared by PECHAN and NESCAUM; downloaded from http://bronze.nescaum.org/Private/junghun/MANE-VU/onroad_ver3_update/MANEVU_V3_update.tar

2.1.4 Point Sources

- Files: MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_041006.txt and MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_041006.txt prepared by PECHAN were downloaded from **ftp.marama.org** (username mane-vu, password exchange)
- Fugitive dust correction: This was applied as county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing
- Corrected the omission of 2,100 tons/year VOC emissions from several point sources in NJ. NJDEP provided updated IDA files on June 30 that were used for modeling.

2.2 CENRAP

The inventory data were obtained from the CENRAP ftp site in March 2006 and reflect version BaseB of the CENRAP inventory.

2.2.1 Area Sources

- Files:
  - CENRAP_AREA_SMOKE_INPUT_ANN_STATES_081705.txt
  - CENRAP_AREA_MISC_SMOKE_INPUT_ANN_STATE_071905.txt
  - CENRAP_AREA_BURNING_SMOKE_INPUT_ANN_TX_NELI_071905.txt
  - CENRAP_AREA_MISC_SMOKE_INPUT_NH3_MONTH_{MMM}_072805.txt where {MMM} is JAN, FEB, … DEC
  - CENRAP_AREA_SMOKE_INPUT_NH3_MONTH_{MMM}_071905.txt where {MMM} is JAN, FEB, … DEC
- Fugitive dust correction: This was applied as county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing
- Note about area and nonroad source SMOKE processing for the CENRAP region: All area source inventories (both annual and month-specific) were processed in

one step through SMOKE. SMK_AVEDAY_YN was set to N, so seasonal profiles were used to apportion the annual inventories numbers by month. This setting was also used for the nonroad processing performed in a separate step. This was necessary since the month-specific files had zero in their 'average-day' column and the annual total column reflects the "monthly emissions as annual totals" as per header line. Therefore, seasonal profiles are used to apportion both the annual and month-specific files. As described below, we utilized the temporal profiles and cross-reference files generated by CENRAP. However, we did not verify that this approach indeed leads to the intended monthly allocation of ammonia and nonroad emissions.

2.2.2 Nonroad Sources

- Files:
  - CENRAP_NONROAD_SMOKE_INPUT_ANN_071305.txt
  - CENRAP_NONROAD_SMOKE_INPUT_MONTH_{MMM}_071305.txt where {MMM} is JAN, FEB, … DEC

2.2.3 Mobile Sources

- VMT/Speed files:
  - mbinv02_vmt_cenrap_ce.ida
  - mbinv02_vmt_cenrap_no.ida
  - mbinv02_vmt_cenrap_so.ida
  - mbinv02_vmt_cenrap_we.ida

2.2.4 Point Sources

- File: CENRAP_POINT_SMOKE_INPUT_ANNUAL_DAILY_072505.txt
- Fugitive dust correction: This was applied as county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing.

2.3 VISTAS

All VISTAS emission files were obtained from the Alpine Geophysics ftp site. They reflect version BaseG of the VISTAS inventory with the exception of fire emissions which reflect BaseF and BaseD. These files were downloaded between February and August, 2006.

2.3.1 Area Sources

- Files:

  - arinv_vistas_2002g_2453922_w_pmfac.txt
  - ida_ar_fire_2002_vistaonly_basef.ida
- Note: the header lines of these files indicate that the fugitive dust correction was already applied, so no further correction was performed.

2.3.2 Nonroad Sources

- Files:
  - nrinv_vistas_2002g_2453908.txt
  - marinv_vistas_2002g_2453972.txt

2.3.3 Mobile Sources

- VMT/Speed file: mbinv_vistas_02g_vmt_12jun06.txt

2.3.4 Point Sources

- Files:
  - Annual:
    - egu_ptinv_vistas_2002typ_baseg_2453909.txt
    - negu_ptinv_vistas_2002typ_baseg_2453909.txt
    - ptinv_fires_{MM}_typ.vistas.ida where {MM} is 01, 02, 03, etc. depending on the month; these annual point fire files were generated as part of the VISTAS BaseD inventory and were obtained in January 2005
  - Hour-specific:
    - pthour_2002typ_baseg_{MMM}_28jun2006.ems where {MMM} is jan, feb, mar, etc.
    - pthour_fires_{MM}_typ.vistas.ida where {MM} is 01, 02, 03, etc. depending on the month; these hourly point fire files were generated as part of the VISTAS BaseD inventory and were obtained in January 2005
- Note: No fugitive dust correction was performed for these files.

2.4 MRPO

MRPO emissions for SMOKE modeling were generated by Alpine Geophysics through a contract from MARAMA to convert the MRPO BaseK inventory from NIF to IDA format. The files were downloaded from the MARAMA ftp site **ftp.marama.org** (username mane-vu, password exchange) between April and June 2006.

2.4.1 Area Sources

- Files:
  - Annual:
    - arinv_mar_mrpok_2002_27apr2006.txt
    - arinv_other_mrpok_2002_20jun2006.txt
  - Month-specific:

    - arinv_nh3_2002_mrpok_{mmm}_3may2006.txt where {mmm} is jan, feb, etc.
    - dustinv_2002_mrpok_{mmm}_23may2006.txt where {mmm} is jan, feb, etc.
- Fugitive dust correction: This correction was performed only to the arinv_other_mrpok_2002_20jun2006.txt file using county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing.
- Note about area source SMOKE processing: SMOKE processing was performed separately for the annual and month-specific files. For the annual inventory processing, SMK_AVEDAY_YN was set to N, so seasonal profiles were used to apportion the annual inventories numbers by month. For the month-specific inventory processing, this variable was set to Y so that no seasonal profiles would be applied and the inventory numbers in the 'average day' column would be used. To save a SMOKE processing step, the annual "marine" inventory "arinv_mar_mrpok_2002_27apr2006.txt" was processed together with the annual "other area source" inventory "arinv_other_mrpok_2002_20jun2006.txt" even though it technically is part of the nonroad inventory.

2.4.2 Nonroad Sources

- Files: nrinv_2002_mrpok_{mmm}_3may2006.txt where {mmm} is jan, feb, etc.

2.4.3 Mobile Sources

- VMT/Speed file: mbinv_mrpo_02f_vmt_02may06.txt

2.4.4 Point Sources

- Files: ptinv_egu_negu_2002_mrpok_1may2006.txt
- Fugitive dust correction: This correction was performed only to the arinv_other_mrpok_2002_20jun2006.txt file using county-specific correction factors for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from EPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected).; this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing.

2.5 Canada

2.5.1 Area Sources

- File: AS2000_SMOKEready.txt obtained from ftp://ftp.epa.gov/EmisInventory/canada_2000inventory
- Fugitive dust correction: We applied "divide-by-four" correction for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; this adjustment was performed outside SMOKE with in-house Fortran programs. No county/province-specific correction factors were available for Canada

2.5.2 Nonroad Sources

- File: NONROAD2000_SMOKEready.txt obtained from ftp://ftp.epa.gov/EmisInventory/canada_2000inventory

2.5.3 Mobile Sources

- File: MOBILE2000_SMOKEready.txt obtained from ftp://ftp.epa.gov/EmisInventory/canada_2000inventory
- Fugitive dust correction: applied "divide-by-four" correction for SCC's listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; this adjustment was performed outside of SMOKE with in-house Fortran programs. No county/province-specific correction factors were available for Canada.

2.5.4 Point Sources

There has long been difficulty in obtaining an up-to-date Canadian criteria emissions inventory for point sources. This is due largely to confidentiality rights afforded to Canadian facilities. Thus far, the most recent inventory of Canadian point sources is rooted in the 1985 NAPAP data and is close to two decades old. Because there are a number of high emitting industrial facilities in southern Canada it is of particular importance to have a reasonably accurate inventory of these sources especially when modeling air quality over the Northeast and Midwest United States. Toward this end, an effort was made to obtain more recent Canadian point source data and incorporate it into an inventory database, which could then be used for the 2002 OTC air quality modeling.

Perhaps the most accurate and publicly accessible source of Canadian pollutant data is now available from the National Pollutant Release Inventory (NPRI) database. This database contains 268 substances. Facilities that manufacture, process or otherwise use one of these substances and that meet reporting thresholds are required to report these emissions to Environment Canada on an annual basis. The NPRI data are available at Environment Canada's website and can be found at the link http://www.ec.gc.ca/pdb/npri/npri_home_e.cfm. The page hosts an on-line search engine where one can locate emissions by pollutant or location. In addition, the entire database is available for download as an MS Access or Excel file. The NPRI database contains numerous pages with a rather comprehensive list of information. Detailed information is available about each facility, including location, activity and annual emissions. In addition, facilities having stacks with a height of 50 meters or more are required to report stack parameters.

Unfortunately, one of the limitations of the NPRI database for modeling purposes is that the data are only available at the facility level. Emissions models require process level information, so in order to use this data, a few generalizations had to be made. Each facility has a Standard Industrial Classification (SIC) code associated with it; however, emissions models require Source Classification Codes (SCC's). SCC's are of critical importance as the emissions models use these codes for assignment of temporal and speciation profiles. SIC codes describe the general activity of a facility while SCC codes describe specific processes taking place at each facility. While no direct relationship exists between these two codes, a general albeit subjective association can be made.

For the purposes of creating a model-ready inventory file it was necessary to obtain the whole NPRI database. After merging all the necessary components from the NPRI database required in the SMOKE inventory file, the SIC code from each facility was examined and assigned an SCC code. In most cases, only a SCC3 level code was assigned with confidence. While this is admittedly a less than desirable process, it does allow for the use of the most recent emissions from the NPRI database to be used in modeling. Furthermore, having some level of SCC associated with these emissions will ensure that they will be assigned a temporal and speciation profile by the model, other than the default. Once the model-ready inventory file was developed, it was processed through SMOKE.

3. Mobile6 Processing

3.1 MANE-VU

3.1.1 Mobile6 input files

- Month-specific input files were prepared by PECHAN and NESCAUM and were downloaded from http://bronze.nescaum.org/Private/junghun/MANE-VU/onroad_ver3_update/MANEVU_V3_update.tar
- Added the line "REBUILD EFFECTS :0.10" to each file before the SCENARIO record to override the Mobile6 default setting of 0.9 (90%) for the "chip reflash" effectiveness

3.1.2 SMOKE/Mobile6 auxiliary files

- SMOKE/Mobile6 auxiliary files were prepared by PECHAN and NESCAUM and were downloaded from http://bronze.nescaum.org/Private/junghun/MANE-VU/onroad_ver3_update/MANEVU_V3_update.tar

3.1.3 Temperature averaging

- Following the setting in the MANEVU_2002_mvref.txt files, the following procedures were used by SMOKE for temporal and spatial temperature averaging in the calculation of emission factors:
  - Spatial averaging: temperatures were averaged over all counties that share a common reference county (i.e. Mobile6 input file)
  - Temporal averaging for May – September emissions processing: no temporal averaging was used, i.e. day-specific temperatures were used to calculate emission factors for each day.
  - Temporal averaging for non-summer-months emissions processing: Temporal averaging over the duration of the episode (i.e. the entire month, see introduction) was used, i.e. monthly average temperatures were used to calculate the emission factors.

3.2 CENRAP

3.2.1 Mobile6 input files

- Mobile6 input files for the CENRAP region for January and July were contained in the files central_M6_{MMM}.zip, north_M6_{MMM}.zip, south_M6_{MMM}.zip, west_M6_{MMM}.zip where {MMM} is either jan or jul. July input files were used for April – September processing, while January input files were used for the remaining months
- All files were downloaded from the CENRAP ftp site in March 2006.

3.2.2 SMOKE/Mobile6 auxiliary files

- SMOKE/Mobile6 auxiliary files were contained in the files central_M6_RD.zip, north_M6_RD.zip, south_M6_RD.zip, and west_M6_RD.zip. The SMOKE MCREF, MVREF, and MCODES files were contained in the file MOBILESMOKE_Inputs.zip. The MCREF and MVREF files were combined for the different regions ("central", "east", "west", "north")
- All files were downloaded from the CENRAP ftp site in March 2006.

3.2.3 Temperature averaging

- The following procedures were used by SMOKE for temporal and spatial temperature averaging in the calculation of emission factors according to the setting in the mvref files:
  - Spatial averaging: no spatial averaging of temperatures, i.e. the temperatures for the reference county is used to calculate emission factors for all counties that share this reference county (i.e. Mobile6 input file)
  - Temporal averaging: Temporal averaging over the duration of the episode (i.e. the entire month, see introduction) was used, i.e. monthly average temperatures were used to calculate the emission factors.

3.3 VISTAS

3.3.1 Mobile6 input files

- Month-specific Mobile6 input files were obtained from the Alpine Geophysics ftp site in July 2006. They reflect version BaseG of the VISTAS inventory.

3.3.2 SMOKE/Mobile6 auxiliary files

- SMOKE/Mobile6 auxiliary files utilized were obtained from the Alpine Geophysics ftp site in July 2006. They reflect version BaseG of the VISTAS inventory.

3.3.3 Temperature averaging

- The following procedures were used by SMOKE for the temporal and spatial temperature averaging in the calculation of emission factors according to the setting in the mvref_baseg.36k.ag.txt file:
  - Spatial averaging: temperatures averaged over all counties that share a common reference county (i.e. Mobile6 input file)
  - Temporal averaging: Temporal averaging over the duration of the episode (i.e. the entire month, see introduction) was used, i.e. monthly average temperatures were used to calculate the emission factors.

3.4 MRPO

3.4.1 Mobile6 input files

- Month-specific Mobile6 input files for SMOKE modeling were generated by Alpine Geophysics through a contract from MARAMA. They are based on version BaseK of the MRPO inventory. The files were downloaded from the MARAMA ftp site **ftp.marama.org** (username mane-vu, password exchange) in May 2006.

3.4.2 SMOKE/Mobile6 auxiliary files

- SMOKE/Mobile6 auxiliary files for SMOKE modeling were generated by Alpine Geophysics through a contract from MARAMA. They are based on version BaseK of the MRPO inventory. The files were downloaded from the MARAMA ftp site **ftp.marama.org** (username mane-vu, password exchange) in May 2006.

3.4.3 Temperature averaging

- The following procedures were used by SMOKE for the temporal and spatial temperature averaging in the calculation of emission factors according to the setting in the mvreg_mrpo_basek.txt file:
  - Spatial averaging: temperatures averaged over all counties that share a common reference county (i.e. Mobile6 input file)

- Temporal averaging: Temporal averaging over the duration of the episode (i.e. the entire month, see introduction) was used, i.e. monthly average temperatures were used to calculate the emission factors.

4. Biogenic Emission Processing

Hourly gridded biogenic emissions for the 12 km and 36 km modeling domains were calculated by BEIS3.12 through SMOKE, using MCIP-processed MM5 fields for temperature ("TA", layer-1 temperature), solar radiation ("RGRND"), surface pressure ("PRES"), and precipitation ("RN" and "RC"). A 'seasonal switch' file was generated by the SMOKE utility metscan to determine whether winter or summer emission factors should be used for any given grid cell on any given day. Winter emission factors are used from January 1st through the date of the last frost and again from the data of the first frost in fall through December 31st. Summer emission factors are used for the time period in between. This calculation is performed separately for each grid cell.

5. Temporal Allocation

5.1 MANE-VU

5.1.1 Area and nonroad sources

- Generated as part of the MANE-VU version 1 inventory
- amptpro.m3.us+can.manevu.030205.txt
- amptref.m3.manevu.012405.txt
- downloaded from **ftp.marama.org** (username mane-vu, password exchange) in January 2005

5.1.2 Mobile sources

- MANEVU_2002_mtpro_02022006_addCT.txt
- MANEVU_2002_mtref_02022006_addCT.txt
- prepared by PECHAN and NESCAUM and downloaded from http://bronze.nescaum.org/Private/junghun/MANE-VU/onroad_ver3_update/MANEVU_V3_update.tar

5.1.3 Point Sources

- Based on the same files as for the MANE-VU area and nonroad temporal files listed above, but added the CEM-based 2002 state-specific temporal profiles and cross-references for EGU sources for the MANE-VU states that were generated by VISTAS for their BaseD modeling and obtained in February 2005.
- No CEM-based hour-specific EGU emissions were utilized

5.2 CENRAP

The following temporal profiles and cross-reference files were used:

- Area and nonroad sources:
    - amptpro.m3.us+can.cenrap.010605_incl_nrd.txt
    - amptref.m3.cenrap.010605_add_nh3_and_nrd.txt
- Mobile sources:
    - mtpro.cenrap.v3.txt
    - mtref.cenrap.v3.txt
- Point sources:
    - ptpro.{QQ}.cenrap_egus_cem.00-03avg.121205.txt where {QQ} is Q1 for January/February/March, Q2 for April/May/June, etc.
    - ptref.{QQ}.cenrap_egus_cem.00-03avg.121205.txt where {QQ} is Q1 for January/February/March, Q2 for April/May/June, etc.
- All files were downloaded from the CENRAP ftp site in March 2006.

5.3 VISTAS

The following month-specific temporal profiles and cross-reference files were used:

- Area and nonroad sources:
    - atpro_vistas_basef_15jul05.txt
    - atref_vistas_basef_15jul05.txt
- Mobile sources:
    - mtpro_vistas_basef_04jul05.txt
    - mtref_us_can_vistas_basef_04jul05.txt
- Point sources:
    - ptpro_typ_{MMM}_vistasg_28jun2006.txt where {MMM} is jan, feb, mar, etc.
    - ptref_typ_vistas_baseg_28jun2006.txt
- These files were obtained from the Alpine Geophysics ftp site. They reflect version BaseG of the VISTAS inventory for the point source allocation files and version BaseF for the area, nonroad, and mobile source allocation files. These files were downloaded between February and July, 2006.

5.4 MRPO

The following month-specific temporal profiles and cross-reference files were used for all source categories:

- amptpro_typ_us_can_{MMM}_vistas_27nov04.txt where {MMM} is jan, feb, mar, etc.
- amptref_2002_us_can_vistas_17dec04.txt
- These files were obtained from VISTAS in January 2005 and reflect their BaseD modeling. No updated temporal profiles or cross-reference files were developed for use with the MRPO BaseK inventory.

5.5 Canada

For Canada, the SMOKE2.1 default temporal profiles and cross-reference files (amptpro.m3.us+can.txt and amptref.m3.us+can.txt) were utilized.

6. Speciation

The same speciation profiles (gspro.cmaq.cb4p25.txt) and cross-references (gsref.cmaq.cb4p25.txt) were utilized for all regions and all source categories. Different versions of these files were obtained (SMOKE2.1 default, EPA-CAIR modeling, VISTAS, CENRAP and MANE-VU) and compared. After comparing the creation dates and header lines of these files, it was determined that the EPA-CAIR and MANE-VU files had the most recent updates, and consequently the final speciation profile and cross-reference files used for all regions and source categories was based on the EPA-CAIR files with the addition of MANE-VU specific updates.

7. Spatial Allocation

7.1 U.S.

The spatial surrogates for the 12 km domain were extracted from the national grid 12 km U.S. gridding surrogates posted at EPA's website at
http://www.epa.gov/ttn/chief/emch/spatial/newsurrogate.html
The gridding cross-references were also obtained from this website, but for the processing of MANE-VU area source emissions, MANE-VU specific cross-reference entries posted on the MARAMA ftp site were added.

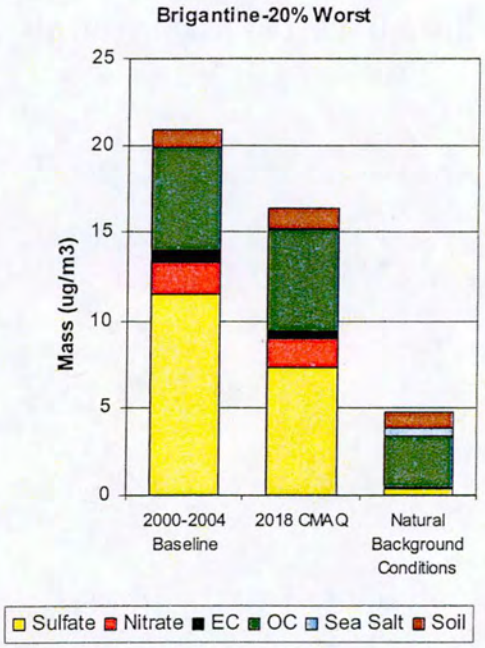
7.2 Canada

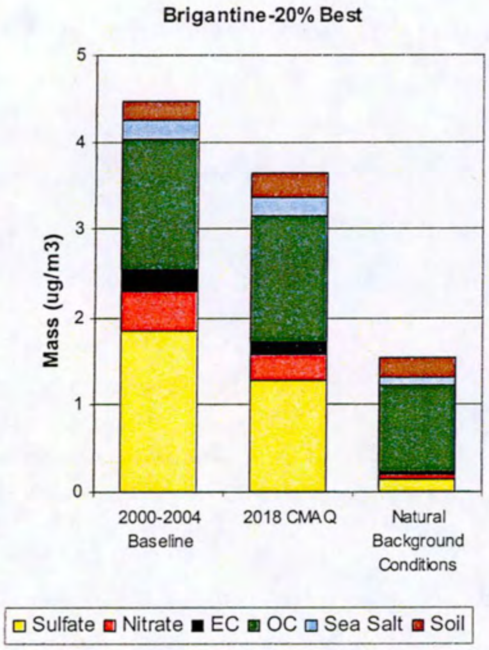
The spatial surrogates for Canadian emissions for the 12 km domain were extracted from the national grid 12 km Canadian gridding surrogates posted at EPA's website at
http://www.epa.gov/ttn/chief/emch/spatial/newsurrogate.html
The gridding cross-references were also obtained from this website.

ATTACHMENT Q

MANE-VU 2018 Visibility Projections

2018 VISIBILITY PROJECTIONS





Prepared by
NESCAUM
For the
Mid-Atlantic/Northeast Visibility Union Regional Planning Organization

May 13, 2008

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2018 VISIBILITY PROJECTIONS

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2018 VISIBILITY PROJECTIONS

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Executive Summary

This report represents the most detailed effort to date to quantify the visibility impacts of those measures that are being actively considered by the Mid-Atlantic/Northeast Visibility Union (MANE-VU) states as a result of the regional haze consultation process. The visibility projections presented here will be useful to the MANE-VU states as they establish reasonable progress goals and develop their long-term emissions management strategies for Class I areas under the federal Regional Haze Rule.

Over the past several years, NESCAUM – as a partner in the MANE-VU regional planning organization – has coordinated and conducted regional air quality modeling to better understand the visibility implications of a range of potential compliance options with the Haze Rule. NESCAUM has utilized in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 and several future periods. This work has been documented in several prior reports that were intended to inform and encourage the decision making process leading up to this point in the SIP submission process.

Results from prior analyses have shown that sulfate aerosol – the dominant contributor to visibility impairment in the Northeast's Class I areas on the 20 percent worst visibility days – has significant contributions from states throughout the eastern U.S. These are projected to continue in future years from all three of the eastern regional planning organizations (RPOs). This assessment of potential control measures that would address these future contributions includes a number of specific strategies and would yield significant visibility benefits at or beyond the uniform rate of progress. Perhaps more importantly, they reflect future visibility benefits corresponding to measures that the MANE-VU states are evaluating as being reasonable to implement.

INTRODUCTION

1.1. Background

This report presents information intended to assist states in establishing reasonable progress goals and fulfilling their long-term emissions management strategies under the 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)] for MANE-VU Class I areas.[1] NESCAUM has used in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 (representative of the baseline period from 2000 to 2004) and for the end of the first compliance period, 2018.

In reviewing the results here, the reader should refer to prior reports prepared by NESCAUM that provide the foundation upon which these results are built. For example, dating back to the earliest overview of regional haze and visibility impairment in the Northeast and Mid-Atlantic U.S. (NESCAUM, 2001), NESCAUM presented a review of the available models along with their uses and limitations. This served to inform the choice of models and tools used to build the weight of evidence modeling approach taken by MANE-VU in conducting a contribution assessment and pollution apportionment (NESCAUM 2004, 2006). NESCAUM presented a review of the base year 2002 from a meteorological and chemical perspective in its report *2002, A Year in Review* (NESCAUM, 2004). NESCAUM has also separately published a performance evaluation of the MM5 meteorological model, the U.S. EPA Community Multi-scale Air Quality (CMAQ) chemical transport model, as well as a more complete description of the modeling platform used for prior control strategy analyses (NESCAUM, 2008).

In this report, we do not repeat this information, but rather rely upon the prior documentation. The following sections describe the control scenario being considered and present the resulting visibility projections in the context of the uniform rate of progress determined by baseline conditions and estimated natural visibility conditions for each Class I area.

1.2. Meteorology

MANE-VU has adopted the Inter-RPO domain description for its modeling runs.[2] This 36-km grid cell domain covers the continental United States, southern Canada, and northern Mexico. The dimensions of this domain are 145 and 102 cells in the east-west and north-south directions, respectively. A 12-km grid cell inner domain was selected to better characterize air quality in MANE-VU and surrounding RPO regions. This domain covers the eastern region, which includes the northeastern, central, and southeastern U.S.,

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

[2] The modeling system for the 2002/2018 annual simulation is applied with a Lambert Conformal Conic projection with parallels at 33°N and 45°N. A spherical earth radius of 6,370 km is used for all elements of the system (MM5/SMOKE/CMAQ).

as well as southeastern Canada. It extends from 66°W~94°W in longitude and 29°N~50°N in latitude with 172 × 172 grid cells (Figure 2-1).

Figure 2-1. Modeling domains used with CMAQ for MANE-VU studies.

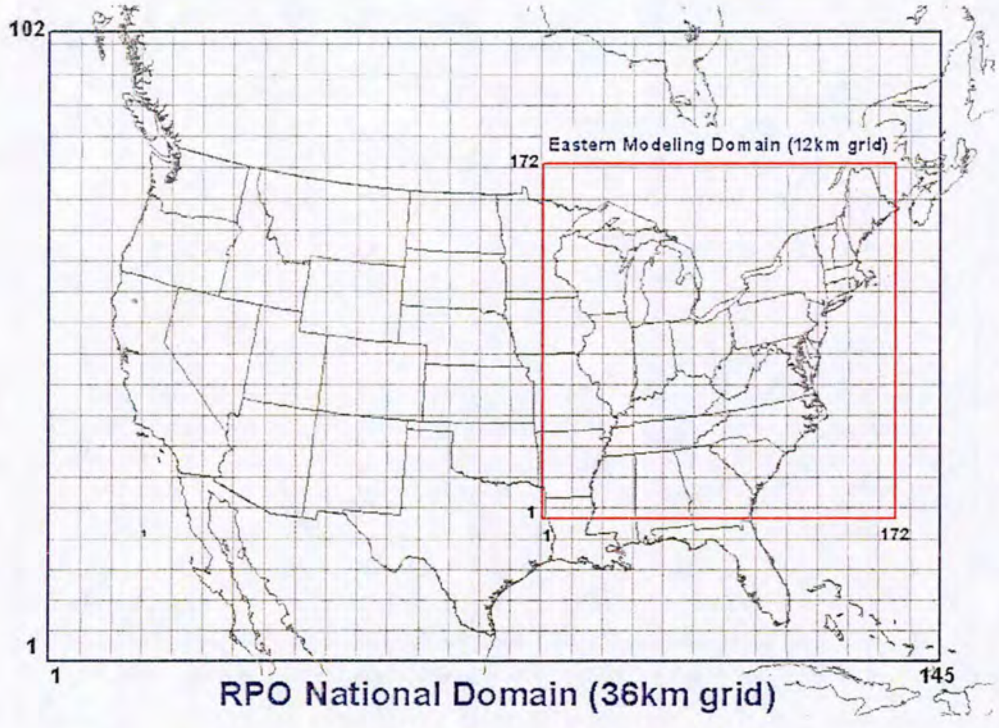

Figure note: Outer (blue) domain is a 36 km grid and inner (red) domain is a 12 km grid. The gridlines are shown at 180 km intervals (5 × 5 36 km cells/15 × 15 12 km cells).

Meteorological inputs for CMAQ, provided by Dalin Zhang's group at the University of Maryland (UMD), are derived from the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5).[3] The UMD MM5 model runs are made on these two nested domains with the inner (12 km) domain using finer resolution terrain data. Initially, we conducted a set of test runs for the period of August 6–16, 2002. A detailed description of the meteorological inputs can be found in the report *MANE-VU Modeling for Reasonable Progress Goals* (NESCAUM 2008).

1.3. Emissions Preparations

NESCAUM simulated emission scenarios using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, an emissions processing system designed to create gridded, speciated, hourly emissions for input into a variety of air quality models such as CMAQ. SMOKE supports area, biogenic, mobile (onroad and nonroad),

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[3] http://www.mmm.ucar.edu/mm5/

and point source emissions processing for criteria, particulate, and toxic pollutants. The *MANE-VU Modeling for Reasonable Progress Goals* report describes the SMOKE emissions processing methods in detail (NESCAUM 2008).

2. 2018 EMISSIONS INVENTORY

Descriptions of the 2002, 2018 On the Books/On the Way (OTB/OTW), and 2018 Beyond on the Way (BOTW) inventories are included in the report on reasonable progress modeling (NESCAUM 2008). Based on this previous modeling, contribution assessments, and analyses of the four statutorily required factors, MANE-VU selected a number of control measures on which to base the modeling that would be used to develop proposed reasonable progress goals. These measures include additional SO_2 emissions reductions at electric generating units (EGUs), the use of low-sulfur fuels in MANE-VU, and reductions in non-EGU SO_2 emissions outside of MANE-VU. Revisions due to implementation of BART and anticipated changes in Canadian emissions are also included in the projected 2018 emissions inventory used for this modeling.

MANE-VU received comments from several stakeholders and another RPO related to the fact that the modeling described in this report included control measures and emission reductions that went beyond currently existing regulations. Commenters suggested that since the CAIR program and other "on the books" or "on the way" measures are projected to achieve uniform rates of progress as previously modeled, additional reductions to both EGU and non-EGU sectors were unnecessary. As described below, there are two reasons why MANE-VU has chosen to include these measures in this modeling analysis.

First, while the results of the modeling described in this report suggest individual MANE-VU Class I areas will be able to meet or exceed uniform rates of progress by 2018, our current analysis also suggests that this would be difficult without including additional measures beyond implementation of CAIR. This result is due, in part, to our assumptions about the effectiveness of CAIR. We believe that it is appropriate for MANE-VU to take a conservative approach to estimating the potential for emissions reductions under the CAIR program. Therefore MANE-VU added EGU emissions to estimate the impact of banking and trading under CAIR. Additional EGU reductions would be feasible with additional federal action to control EGU emissions (e.g., a third phase of CAIR), but MANE-VU does not believe that these reductions are likely to occur absent additional regulation.

Second, EPA's Regional Haze Rule requires that states must identify and consider all potential measures that could improve visibility and the preamble contains language indicating that states should adopt the amount of progress required to achieve the uniform rate as its target "unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy." [40 CFR part 51, July 1, 1999, pg. 35,732].

MANE-VU Class I states have concluded based on review of four factor analyses that the control assumptions described below for all three RPOs represent reasonable ways to achieve the goals MANE-VU set forth in consultations. MANE-VU understands that states will document in their Regional Haze SIPs any difference of opinion as to whether reasonable measures exist beyond CAIR for EGUs and as to what measures are reasonable in the non-EGU sector.

The following sections describe the adjustments made to the BOTW inventory to develop the visibility projections documented in this report. These results are available for the MANE-VU states with Class I areas to consider in proposing reasonable progress goals.

2.1. Implementation of Top 167 EGU SO_2 Control Scenario

The Vermont Department of Environmental Conservation (DEC) and Environmental Resources Management, on behalf of the Maryland Department of the Environment/Maryland Department of Natural Resources (MDE/MDNR), simulated sulfate at MANE-VU Class I areas using CALPUFF to identify the major contributors to ambient pollution. The effort identified 167 EGU emission sources as contributing a substantial visibility degradation at northeast Class I sites. As part of the MANE-VU strategy to meet its reasonable progress goals, MANE-VU asked for a 90 percent reduction relative to 2002 emission levels from these stacks. This request did, however, provide flexibility to pursue equivalent reductions by region in lieu of reductions at these specific facilities. The resulting emission levels from the EGU sector for this version of the 2018 MANE-VU inventory reflect the SO_2 control request on the top 167 EGUs over three RPOs: MANE-VU, VISTAS, and MWRPO; while maintaining the SO_2 emission level under the CAIR cap for all states subject to the CAIR cap-and-trade program. A more complete description of the EGU emissions inventory preparation is provided elsewhere (Alpine Geophysics, March 2008).

First, NESCAUM determined the desired emissions levels for the 167 stacks based on continuous emissions monitoring data from 2002 (representing a 90 percent reduction). Table 2-1 displays the target levels summarized by RPO. For the same stacks, states provided their best estimate of emissions in 2018, with IPM results as a starting point and specific knowledge of anticipated activity for each stack (e.g., installation of controls). These future emissions are summed by RPO and shown in the second row of Table 2-1. A comparison of these emissions levels shows that no RPO achieves the desired reductions at these 167 stacks. Therefore, reductions at other stacks at the same facilities as the 167 stacks or from other EGUs are required to meet the target emissions level.

Table 2-1. SO_2 Emissions Summary (TPY) for 167 Top EGU stacks

	MANE-VU	MRPO	VISTAS
10% of 2002 CEMS	117,217	170,454,	169,816
Projected 2018	193,026	436,138	299,090
Shortfall	75,809	265,683	129,275

NESCAUM next reviewed anticipated 2018 emissions by RPO at all stacks other than the 167. For MANE-VU, an emissions reduction exactly matching the shortfall (75,809 tons) was recorded at one hypothetical stack in the region.[4] The VISTAS G2

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[4] This hypothetical reduction was not assigned to any specific source since the subsequent "add back" of emissions reductions not backed up by enforceable regulations led to no net reduction.

inventory with some Virginia adjustments estimated reductions relative to IPM 2.1.9[5] of over 180,000 tons for the EGUs not included in the 167 stacks. These reductions exceed the shortfall from the 167 stacks and no further adjustments were required. For MRPO, IPM 3.0 results (based on RPO communication) were used to guide the location of reductions to meet the shortfall. Emissions from 65 units where IPM 3.0 predicted emissions lower than IPM 2.1.9 were adjusted downward to be 10 percent of 2002 emissions, resulting in 290,551 tons per year of additional reductions.

Once EGU SO_2 emissions levels were lowered to meet the desired reductions, NESCAUM compared the adjusted emissions (including adjustments to IPM 2.1.9 made by states directly and those from changes made by NESCAUM to meet the 167 stack reduction targets) with IPM 2.1.9 emissions by each of the three RPOs. The analyses looked at three groupings of EGU stacks: the 167 stacks, other units at the same facilities as the 167 stacks, and all other EGUs. Table 2-2 gives these differences by category. Since the total IPM 2.1.9 EGU emissions sums to the CAIR cap, the sum of the differences in the table represents reductions beyond the CAIR level. Because MANE-VU Class I states made the decision to maintain the CAIR level of emissions in this 2018 modeling, the 516,350 tons of emissions were added back.

Table 2-2. Emissions difference between IPM 2.1.9 and adjusted emissions based on state-specific comments and MANE-VU effort to meet 167 stack reduction levels.

	MANE-VU	MRPO	VISTAS
167 stacks	39,465	-37,913	-14,673
Other stacks at 167 facilities	21,433	24,098	-2,244
Other EGUs	-75,809	-290,551	-180,155
Sum	-14,912	-304,367	-197,071

Note: negative values indicate emissions below IPM 2.1.9

Next, NESCAUM increased the emissions from states subject to the CAIR cap-and-trade program. For MANE-VU, 75,809 tons were added back to the hypothetical facility controlled to meet the "167 stack" reduction request. The remaining 440,188 tons were allocated to VISTAS and MRPO at EGUs that were not among the "167 Stack" facilities based on the fraction of their contribution to the total SO_2 emission. The additional emissions correspond to an increase of 20.5 percent at each of these facilities, with a total of 216,685 tons added to MRPO and 223,504 tons added to VISTAS.

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[5] To predict future emissions from EGUs, the Mid-Atlantic/Northeast Visibility Union (MANE-VU) and other Regional Planning Organizations have followed the example of the US Environmental Protection Agency (EPA) in using the Integrated Planning Model® (IPM), an integrated economic and emissions model. IPM projects electricity supply based on various assumptions and develops a least-cost solution to generating needed electricity within specified emissions targets. IPM runs are defined by numerous economic and engineering assumptions. EPA developed Base Case v.2.1.9 using IPM to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR). Recently, EPA updated their input data and developed Base Case v.3.0. All of the IPM results used in MANE-VU modeling were based on EPA Base Case v.2.1.9 with some updates and corrections.

The intent of the EGU emissions adjustments was to retain the same overall level of emissions as predicted by the VISTAS/Inter-RPO run of IPM 2.1.9 overall. The locations of the emissions, however, were modified to better reflect the states' estimates of where emissions would be reduced and to implement the MANE-VU "ask" to achieve reductions at the 167 stacks identified as contributors to visibility reduction at MANE-VU Class I areas.

2.2. Implementation of Low Sulfur Fuel Strategy in MANE-VU

This strategy reduces SO_2 emissions by 2018 from all MANE-VU (non-EGU) sources combusting #1, #2, #4, #5, and #6 oil. Reductions were achieved by lowering sulfur content in fuel from their original levels to 0.0015 percent (equivalent to fuel sulfur content of 15 ppm by volume) for #1 and #2 oil; to 0.25 percent for #4 oil; and to 0.5 percent for #5 and #6 oil. Emissions were reduced from 2002 levels by 168,222 for light distillates (#1 and #2) and 42,875 tons per year for the other fuels. These reductions – when applied within MANE-VU – result in a 35% reduction of our projected 2018 non-EGU SO2 inventory.

2.3. Implementation of BART Strategy in MANE-VU

SO_2 emissions at BART-eligible sources that were not controlled for any other reason (e.g., NOx RACT, CAIR, multi-P state regulations, etc.) have been set to levels as determined by the states.

2.4. Implementation of Gas-Turbine EGU in Canada

SO_2 emissions were removed entirely from six coal-burning EGUs in Ontario, Canada (6500 MW of total capacity) that are scheduled to be shut down (Ontario Power Authority 2006) and replaced with nine natural gas turbine units with Selective Catalytic Reduction (SCR). Emission rates for modeled pollutants from the 'new' gas facilities were based on a combination of factors: recommendation from NH DES (Andy Bodnarik, personal communication), a NYSERDA study (Wien et al. 2003) and AP42 ratios among pollutants. Ontario EGU emissions were reduced by more than 144,000 tons per year as a result of this measure.

2.5. Implementation of 28 percent non-EGU SO_2 emission reduction

Given MANE-VU's low sulfur fuel strategy, MANE-VU requested a comparable reduction in SO_2 emissions from MRPO and VISTAS. The 28 percent value derives from a preliminary estimate of emissions reductions reasonably achievable from non-EGUs sources in MANE-VU. Based on 2002 emissions, this level reduction would amount to 131,600 TPY in MRPO and 308,000 TPY in VISTAS. A number of emission reductions were made to reach these levels, including: reducing emissions from coal-fired ICI boilers by 60 percent, reducing emissions from oil-fired ICI boilers by 75 percent, and reducing emissions from ICI Boilers lacking fuel specification by 50 percent. An additional control was required in VISTAS that reduced emissions from other area oil-combustion sources by 75 percent. These sources were identified by SCCs, matching the source types identified in the list of oil combustion SCCs developed by Alpine Geophysics for the sensitivity runs described previously (NESCAUM, 2008).

3. 2018 MODELING PROJECTIONS

The modeling results based on adjustments to the 2018 emissions inventory detailed in the previous section are given here. All results were developed using the CMAQ modeling platform described previously (NESCAUM, 2008). Table 3-1 provides species-specific relative reduction factors (RRFs) at each Class I area for the 20 percent worst and 20 percent best days. The factors are developed from the 2002 baseline modeling and 2018 modeling results. Ambient measurements identify which days to use in the calculations. The model concentrations for these days are averaged to create the RRF, which is the ratio of the future year to base year average concentration.

Based on the tabulated data, modeled sulfate is reduced by about one-third on worst days, and range from a 6 percent to 31 percent reduction on best days. Nitrate and elemental carbon also show substantial reductions across all sites for both best and worst days. Reductions in organic carbon levels are generally small, while increases are predicted for the fine soil component. The increase may be due to differences in the fire inventory used in VISTAS, as the base year relied on an earlier version of fire emissions than did the 2018 inventory. No changes occur for sea salt since the model does not track that component.

To determine visibility levels in 2018, the measured baseline average concentrations are multiplied by their corresponding RRF for each worst and best day. The projected concentrations are then used to derive daily visibility in deciviews and are averaged across all best and worst days to create the projected future visibility. The results of this procedure are plotted along with the uniform progress glide slope in Figure 3-1 through Figure 3-7. In addition, annual observed 20 percent best and 20 percent worst visibility are plotted as well as a line representing no degradation from current baseline best 20 percent visibility.

All MANE-VU sites are projected to meet or exceed the uniform rate of progress goal for 2018 on the 20 percent worst days. In addition, no site anticipates increases in 20 percent best day visibility impairment relative to the baseline. The nearby sites of Shenandoah and Dolly Sods also show improvement relative to baseline conditions on the 20 percent best days. At Dolly Sods, however, projected visibility impairment on the 20 percent worst days in 2018 exceeds the level determined by the uniform rate. Apparently, the net result of adding back SO_2 emissions across the domain in order to maintain the CAIR cap <u>and</u> reducing emissions in the MidWest RPO and VISTAS in order to comply with the MANE-VU non-EGU ask has been to increase the anticipated visibility impairment relative to previous modeled scenarios. This result is most evident at southern and western sites where more emissions (on an absolute basis) were added back to EGUs.

Table 3-1. 2018 20% best and worst days relative reduction factors at seven sites.

20% Worst Days Relative Reduction Factors

	Acadia	Lye Brook	Brigantine	Moosehorn	Dolly Sods	Shenandoah	Great Gulf
SO4	0.65	0.65	0.63	0.69	0.77	0.65	0.63
NO3	0.79	0.91	0.93	0.73	0.55	0.47	0.85
EC	0.75	0.67	0.62	0.77	0.73	0.58	0.74
OC	0.95	0.93	0.98	0.95	0.93	0.88	0.86
Sea Salt*	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Soil	1.10	1.13	1.26	1.09	1.21	1.16	1.15

20% Best Days Relative Reduction Factors

	Acadia	Lye Brook	Brigantine	Moosehorn	Dolly Sods	Shenandoah	Great Gulf
SO4	0.90	0.81	0.69	0.95	0.94	0.91	0.94
NO3	0.75	0.67	0.62	0.77	0.73	0.58	0.74
EC	0.74	0.75	0.64	0.78	0.71	0.52	0.83
OC	0.94	0.93	0.97	0.92	0.91	0.72	0.99
Sea Salt*	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Soil	1.06	1.04	1.17	1.03	1.14	1.08	1.08

* RRFs for Sea Salt are not calculated from CMAQ. We assume no changes in observed values between 2002 and future time periods.

Figure 3-1. Projected improvement in visibility at Acadia National Park based on 2018 Best and Final Projections

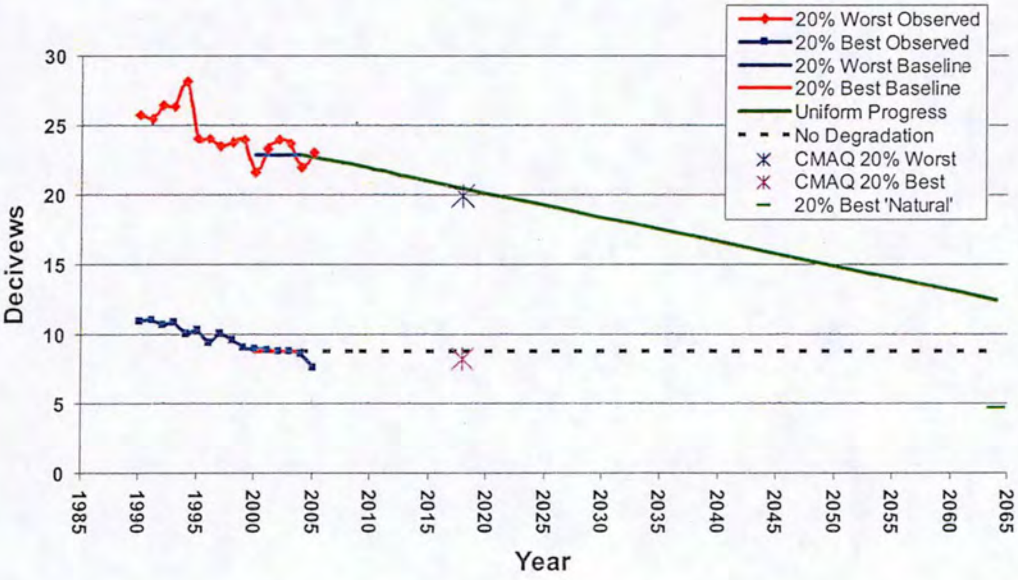


Figure 3-2. Projected improvement in visibility at Brigantine National Wildlife Refuge based on 2018 Best and Final Projections

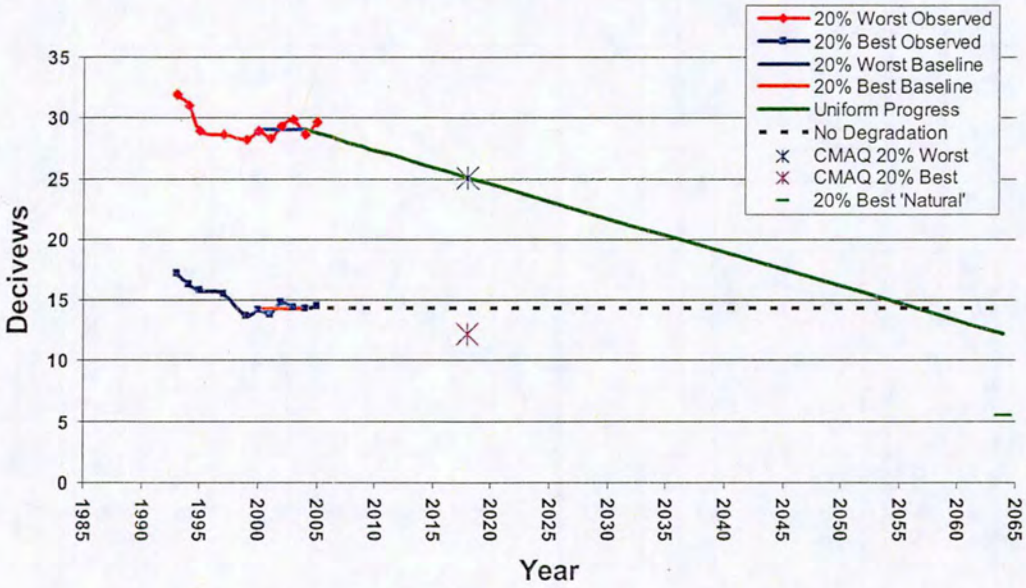


Figure 3-3. Projected improvement in visibility at Great Gulf Wilderness based on 2018 Best and Final Projections

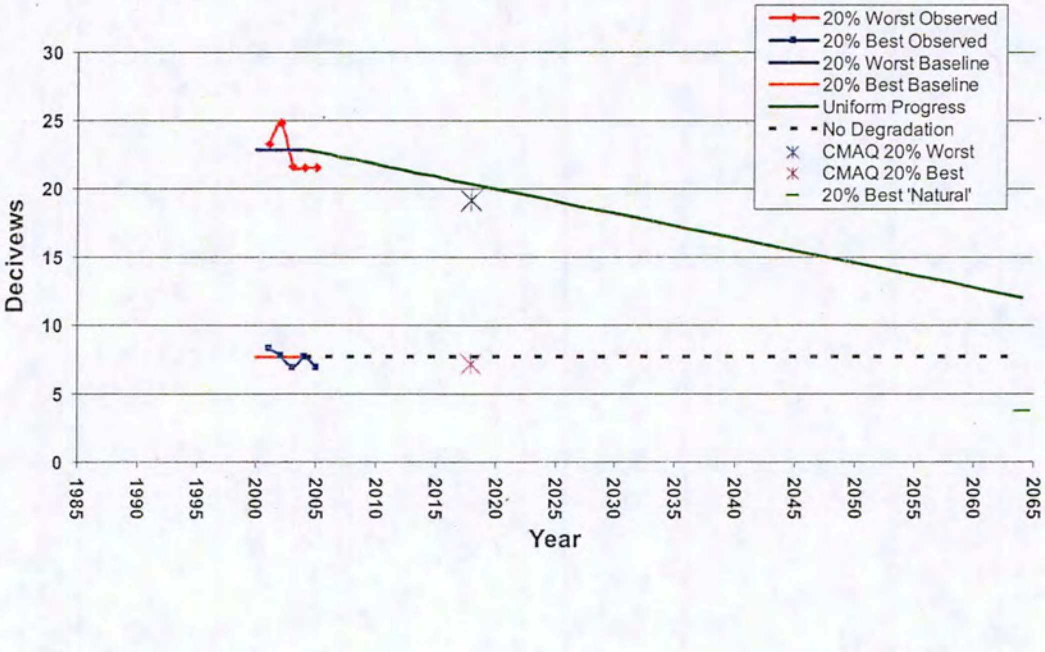


Figure 3-4. Projected improvement in visibility at Lye Brook Wilderness based on 2018 Best and Final Projections

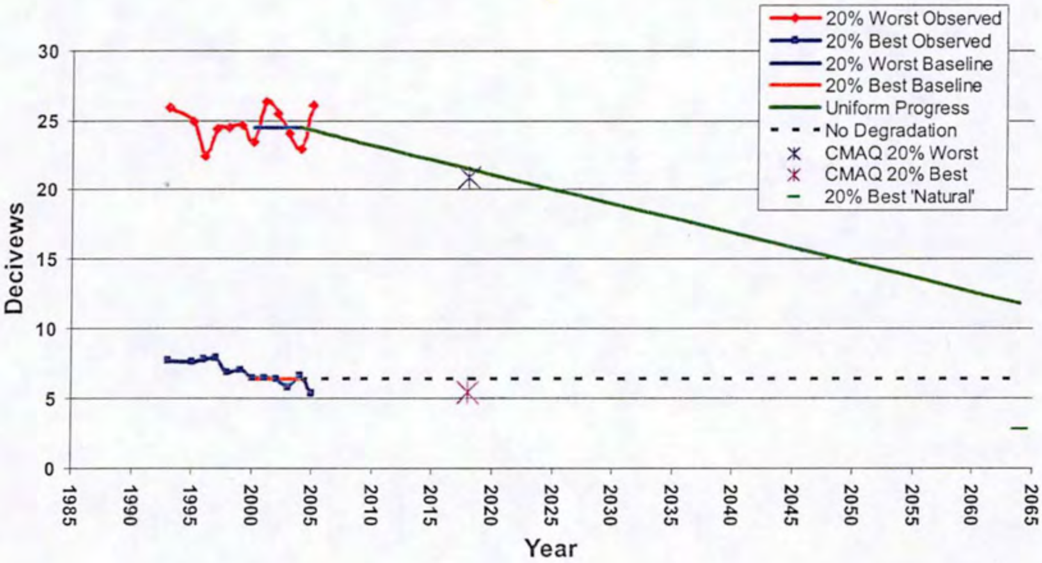


Figure 3-5. Projected improvement in visibility at Moosehorn National Wildlife Refuge based on 2018 Best and Final Projections

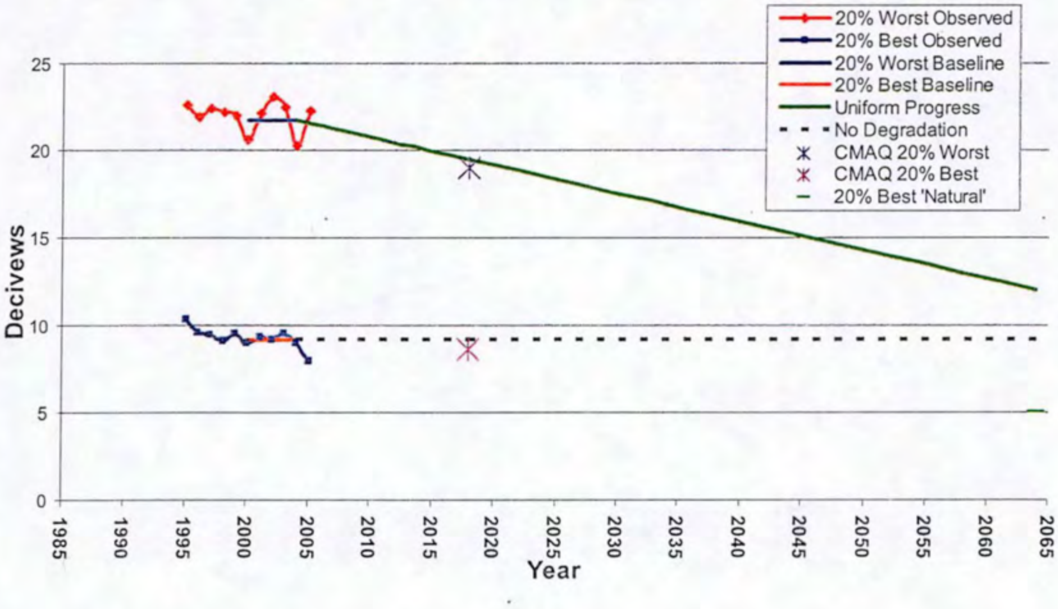


Figure 3-6. Projected improvement in visibility at Dolly Sods Wilderness based on 2018 Best and Final Projections

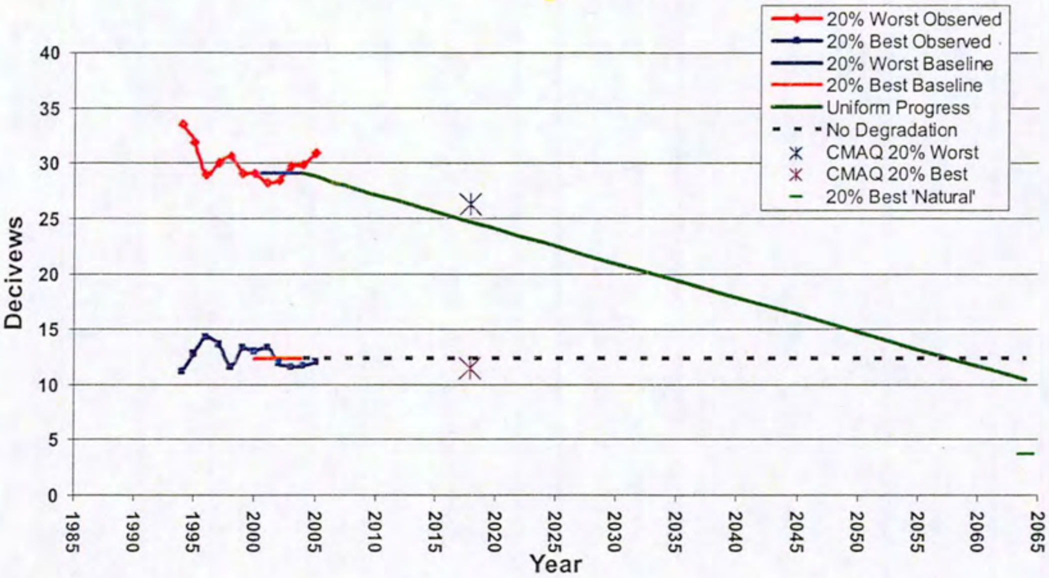
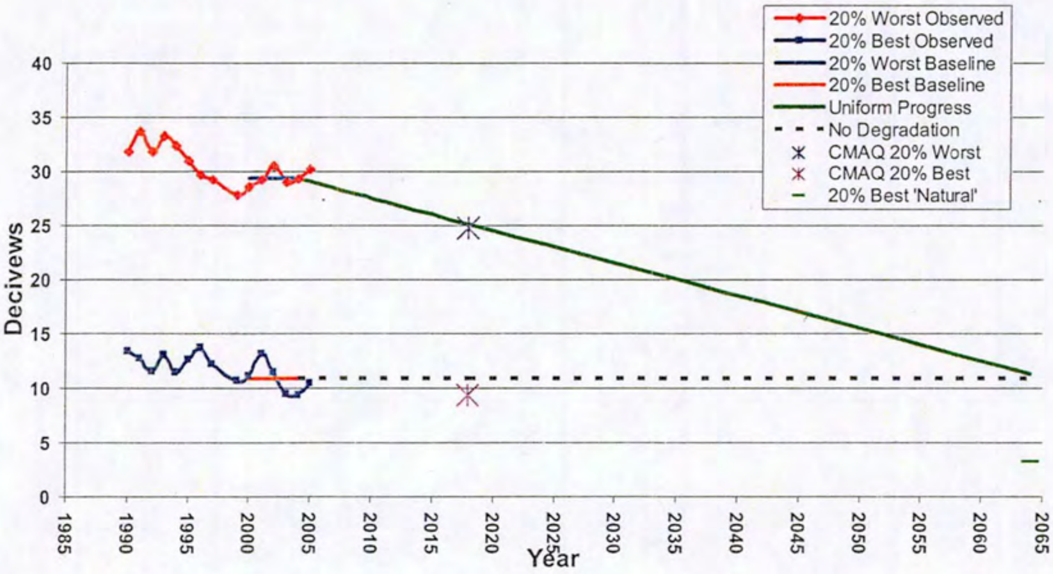


Figure 3-7. Projected improvement in visibility at Shenandoah National Park based on 2018 Best and Final Projections



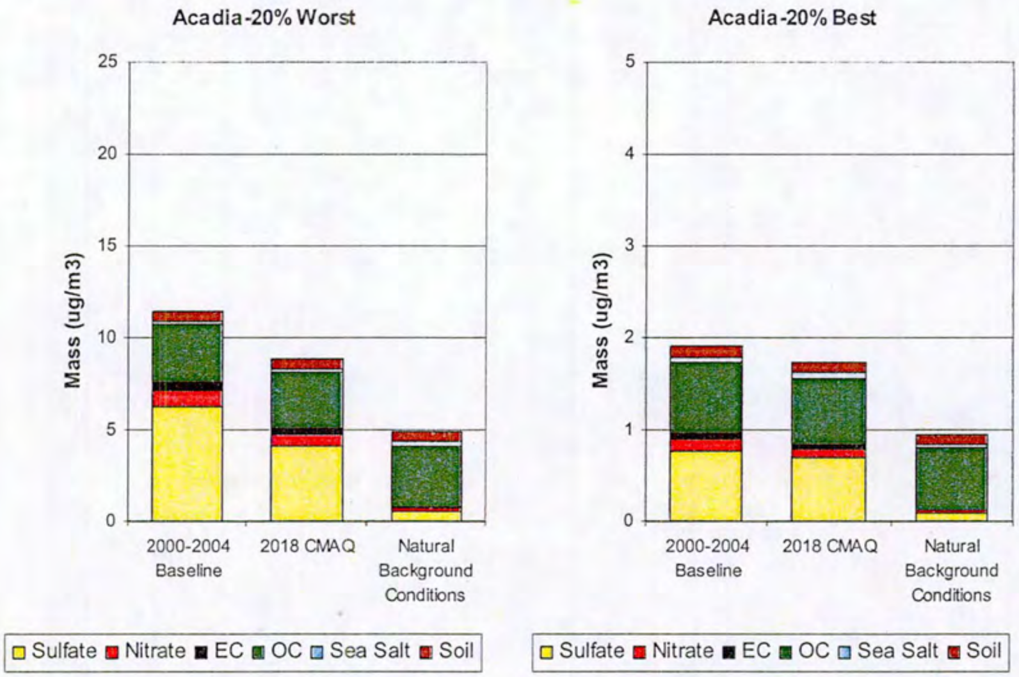
4. 2018 VISIBILITY RESULTS

Figure 4-1A through G show the absolute magnitude of measured and projected sulfate, nitrate, elemental carbon (EC), organic carbon (OC), sea salt, and soil at each MANE-VU Class I monitor and two nearby Class 1 sites, Shenandoah and Dolly Sods. Current and projected vibility conditions are shown for both the twenty percent best visibility days (right) and the twenty percent worst visibility days (left; note that the range of the y-axes are five times greater than for the best days!) These figures show that despite large reductions in sulfate relative to the baseline, substantially greater reductions are required to reach natural background conditions. Reductions in nitrate will also be needed. Similarly, the carbonaceous species warrant attention moving forward, although a substantial fraction of the organic carbon will remain as natural background.

Sea salt shows interesting behavior. At coastal sites, the worst day sea salt mass is shown to increase when going from baseline and 2018 time periods to natural background conditions. Presumably this observation is a result of the EPA/IMPROVE program choice to base future estimates of worst day visibility conditions on the current distribution of worst day visibility. We note that for sea salt, this may not be the best method to estimate future worst day conditions as the greatest concentration of sea salt is observed in the Northeast U.S. on the best visibility days, not the worst visibility days.

Figure 4-1A-G. Observed Baseline, CMAQ-projected*, and Estimated Natural Speciated $PM_{2.5}$ Mass Values for MANE-VU Class I Sites.

A. Acadia National Park



		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	6.29	4.11	0.53
	Nitrate	0.82	0.65	0.21
	EC	0.43	0.33	0.04
	OC	3.17	3.00	3.32
	Sea Salt	0.19	0.19	0.32
	Soil	0.52	0.58	0.52
Visibility	dv	22.9	19.4	12.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	0.77	0.69	0.09
	Nitrate	0.11	0.09	0.03
	EC	0.09	0.06	0.01
	OC	0.76	0.71	0.68
	Sea Salt	0.06	0.06	0.03
	Soil	0.11	0.12	0.10
Visibility	dv	8.8	8.3	4.7

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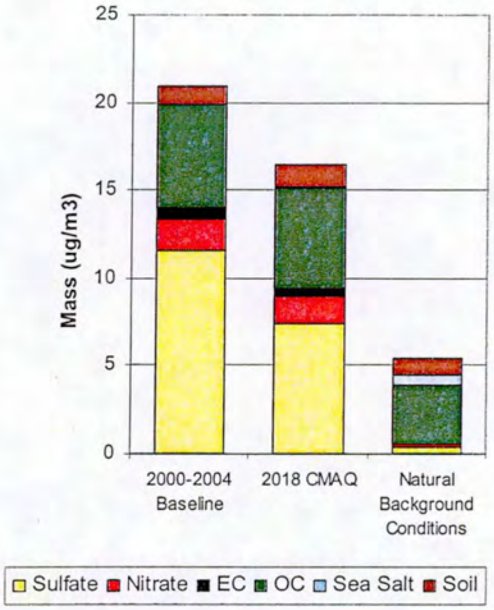
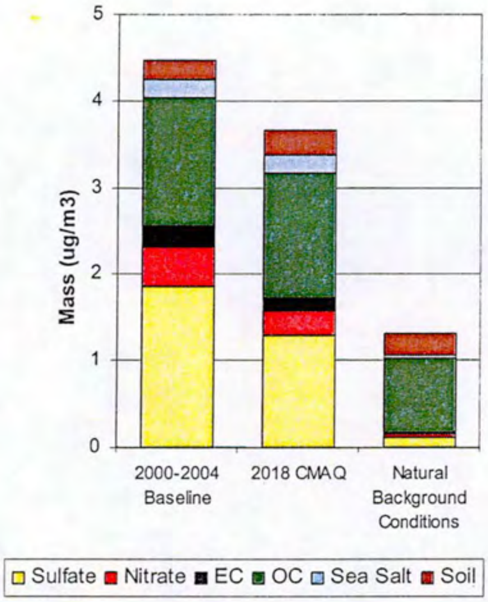
* CMAQ projected values are calculated by applying CMAQ-based RRFs by the observed baseline values.

B. Brigantine National Wildlife Refuge

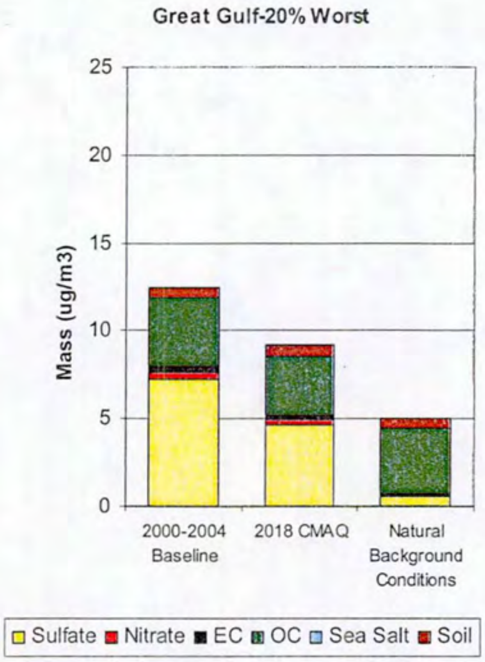

Brigantine-20% Worst

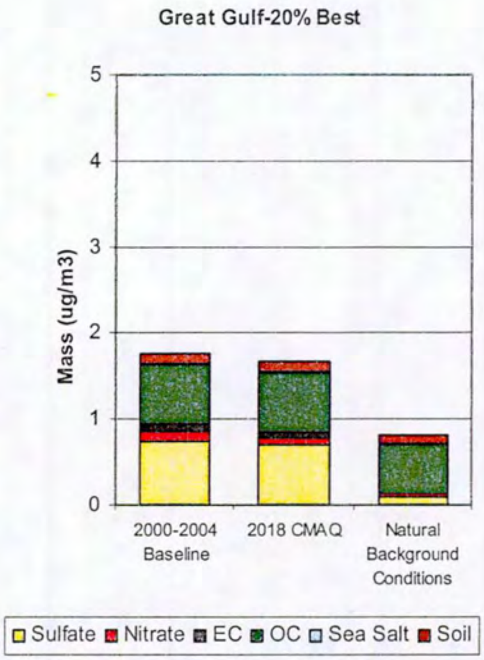

Brigantine-20% Best

		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (μg/m^3)	Sulfate	11.58	7.35	0.39
	Nitrate	1.73	1.60	0.13
	EC	0.70	0.43	0.03
	OC	5.83	5.72	3.40
	Sea Salt	0.06	0.06	0.57
	Soil	0.97	1.23	0.85
Visibility	dv	29.0	25.1	12.2

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (μg/m^3)	Sulfate	1.85	1.28	0.12
	Nitrate	0.46	0.29	0.04
	EC	0.24	0.15	0.01
	OC	1.47	1.43	0.86
	Sea Salt	0.22	0.22	0.04
	Soil	0.23	0.28	0.24
Visibility	dv	14.3	12.2	5.5

C. Great Gulf Wilderness Area

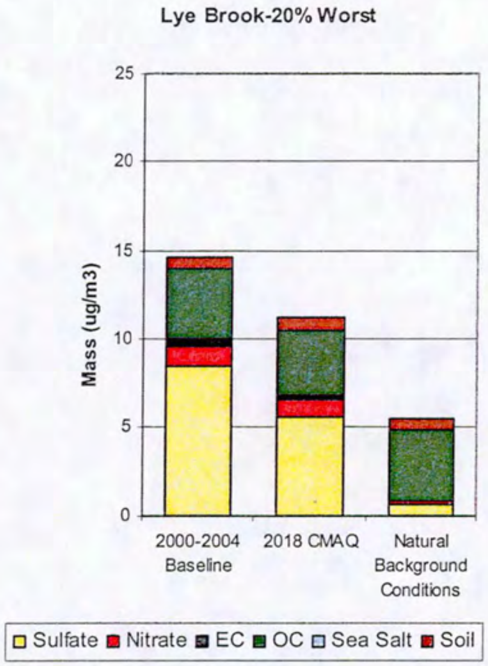


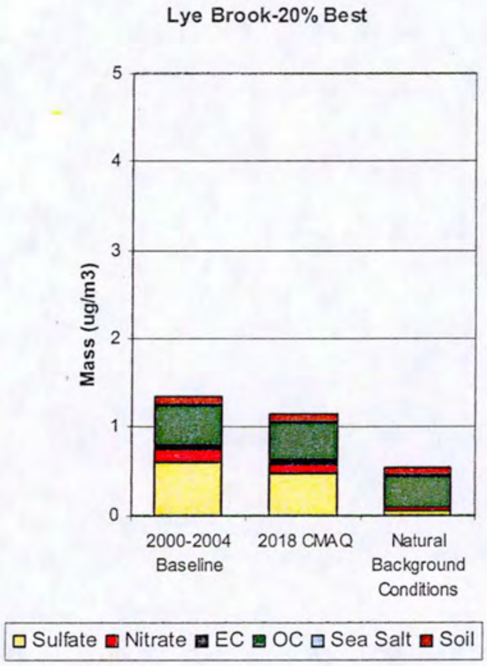


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	7.28	4.61	0.54
	Nitrate	0.36	0.30	0.13
	EC	0.39	0.29	0.04
	OC	3.84	3.31	3.76
	Sea Salt	0.02	0.02	0.02
	Soil	0.57	0.66	0.53
Visibility	dv	22.8	19.1	12.0

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	0.74	0.70	0.09
	Nitrate	0.12	0.09	0.04
	EC	0.08	0.07	0.01
	OC	0.68	0.67	0.56
	Sea Salt	0.03	0.03	0.02
	Soil	0.10	0.11	0.10
Visibility	dv	7.7	7.2	3.7

D. Lye Brook Wilderness Area

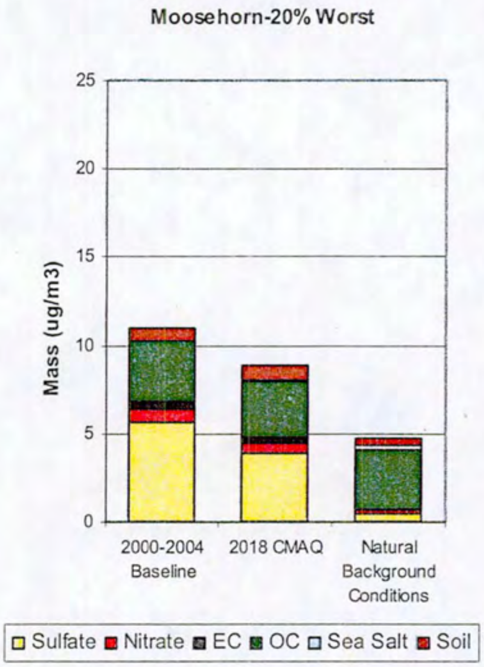


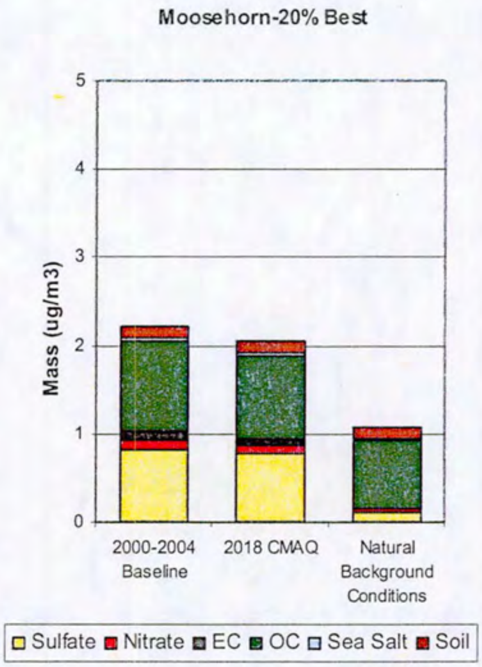


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	8.46	5.52	0.61
	Nitrate	1.07	0.98	0.18
	EC	0.48	0.32	0.04
	OC	3.94	3.67	3.91
	Sea Salt	0.01	0.01	0.01
	Soil	0.64	0.73	0.66
Visibility	dv	24.4	20.9	11.7

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	0.59	0.48	0.05
	Nitrate	0.14	0.10	0.03
	EC	0.06	0.04	0.01
	OC	0.44	0.41	0.36
	Sea Salt	0.01	0.01	0.01
	Soil	0.09	0.10	0.09
Visibility	dv	6.4	5.5	2.8

E. Moosehorn National Wildlife Refuge

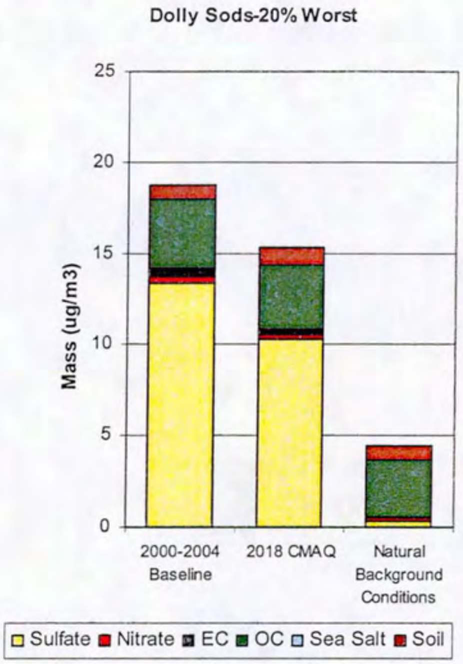


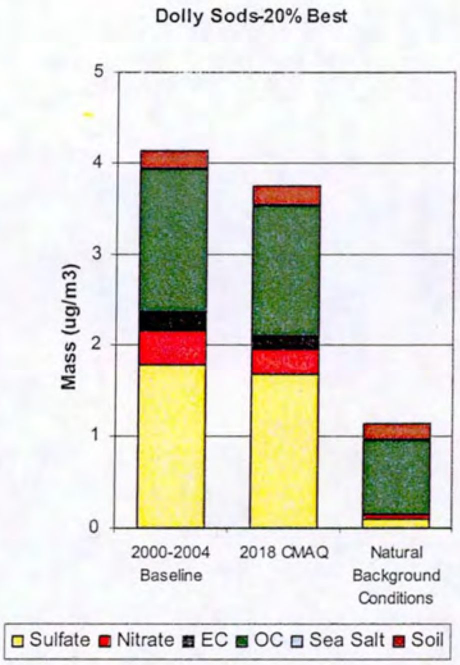


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m³)	Sulfate	5.67	3.90	0.48
	Nitrate	0.71	0.52	0.20
	EC	0.44	0.34	0.04
	OC	3.38	3.20	3.34
	Sea Salt	0.03	0.03	0.24
	Soil	0.76	0.83	0.40
Visibility	dv	21.7	19.0	12.0

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m³)	Sulfate	0.80	0.77	0.11
	Nitrate	0.12	0.09	0.04
	EC	0.10	0.08	0.01
	OC	1.02	0.94	0.76
	Sea Salt	0.04	0.04	0.02
	Soil	0.11	0.12	0.12
Visibility	dv	9.2	8.6	5.0

F. Dolly Sods Wilderness Area

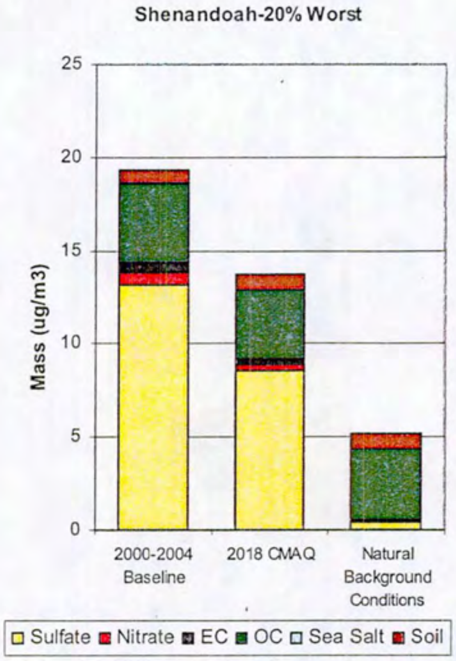

Dolly Sods-20% Worst

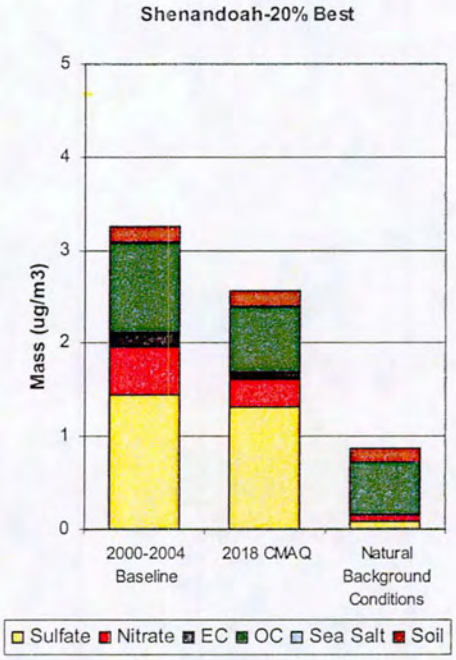

Dolly Sods-20% Best

		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	13.35	10.30	0.38
	Nitrate	0.37	0.20	0.14
	EC	0.47	0.34	0.03
	OC	3.75	3.51	3.11
	Sea Salt	0.02	0.02	0.05
	Soil	0.77	0.94	0.75
Visibility	dv	29.0	26.3	10.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	1.79	1.69	0.10
	Nitrate	0.38	0.27	0.05
	EC	0.21	0.15	0.01
	OC	1.56	1.41	0.80
	Sea Salt	0.02	0.02	0.01
	Soil	0.18	0.20	0.17
Visibility	dv	12.3	11.4	3.6

G. Shenandoah National Park





		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m³)	Sulfate	13.19	8.54	0.43
	Nitrate	0.65	0.31	0.07
	EC	0.57	0.33	0.03
	OC	4.21	3.69	3.78
	Sea Salt	0.01	0.01	0.03
	Soil	0.72	0.84	0.83
Visibility	dv	29.3	24.7	11.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m³)	Sulfate	1.45	1.31	0.08
	Nitrate	0.52	0.30	0.07
	EC	0.16	0.08	0.01
	OC	0.95	0.69	0.56
	Sea Salt	0.02	0.02	0.01
	Soil	0.16	0.17	0.14
Visibility	dv	10.9	9.4	3.1

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ATTACHMENT R

NYSDEC Technical Support Document TSD-1a

TSD-1a

Meteorological Modeling using Penn State/NCAR 5th Generation Mesoscale Model (MM5)

Bureau of Air Quality Analysis and Research
Division of Air Resources
New York State Department of Environmental Conservation
Albany, NY 12233

February 1, 2006

Meteorological Modeling using Penn State/NCAR 5th Generation Mesoscale Model (MM5)

Version 3.6 of MM5 was used to generate annual 2002 meteorology for the OTC modeling work. Prof. Dalin Zhang of the University of Maryland performed the MM5 simulations in consultation with NYSDEC staff. The model was applied in Lambert conformal map projection and utilized MPP Version developed for clusters. The two-way nested domain consisted of coarse (36km) and fine (12km) mesh corresponding to 149x129 and 175x175 grids, respectively, in this application (see Figure 1).

The Lambert projection used in this work followed the Regional Planning Organization (RPO) national domain setup with the center at (40ºN, 97ºW) and parallels at 33ºN and 45ºN. Map projection parameters in reference to the projection center point are as follows: Southwest corner for the 36 km grid is at (-2664km, -2304km) and the northeast corner at (2664km, 2304km). In the case of the 12km grid, the southwest corner is at (252km, -900km) and the northeast corner at (2340km, 1188km). In the vertical direction, the terrain following σ-coordinate system was used with the pressure at each σ-level determined from a reference state that is estimated using the hydrostatic equation from a given sea-level pressure and temperature with a standard lapse rate. There are 30 unevenly spaced σ levels, giving 29 vertical layers, with higher resolution within the planetary boundary layer (PBL). The σ levels are:

1.0000, 0.9974, 0.9940, 0.8980, 0.9820, 0.9720, 0.9590, 0.9430, 0.9230, 0.8990,

0.8710, 0.8390, 0.8030, 0.7630, 0.7180, 0.6680, 0.6180, 0.5680, 0.5180, 0.4680,

0.3680, 0.3180, 0.2680, 0.2180, 0.1680, 0.1230, 0.0800, 0.0400, 0.0000

The surface layer was set at about 10m, the level at which surface winds were typically observed, and the model top was set at 50hPa with a radiative top boundary condition. The time steps for the 36km and 12km domains were 75 and 25 seconds, respectively.

The important model physics options used for this MM5 simulation include:

- Kain-Fritsch (1993) convective scheme for both 36- and 12-km domains
- Explicit moisture scheme (without the mixed phase) containing prognostic equations for cloud water (ice) and rainwater (snow) (Dudhia 1989; Zhang 1989)
- Modified version of the Blackadar planetary boundary layer (PBL) scheme (Zhang and Anthes 1982; Zhang and Zheng 2004)
- Simple radiative cooling scheme (Grell et al. 1994)
- Multi-layer soil model to predict land surface temperatures using the surface energy budget equation (Dudhia 1996)

Note that the Blackadar PBL scheme has been modified in order to correct the phase shift of surface wind speed and temperature diurnal cycle, following a study that compared five different PBL schemes: the Gayno-Seaman TKE scheme (Shafran et al. 2000), Burk-

Thompson (1989), Blackadar (Zhang and Anthes 1982), MRF (Hong and Pan 1996), and Mellor-Yamada-Jajic (Mellor and Yamada 1974; Jajic 1990, 1994). The details of the study can be found at Zhang and Zheng (2004).

Nudging Processes

The MM5 provides options for nudging observations for each domain during the model integration process (Stauffer and Seaman, 1990; Stauffer et al. 1991). The Eta analyses of upper-air winds, temperature and water-vapor mixing ratio as well as their associated surface fields were used for nudging every 6 hours, and the Eta surface wind fields blended with surface wind observations were used to nudge every 3 hours. While only the surface winds were nudged, their influences could extend into the PBL as well (see Stauffer et al. 1991). Based on UMD's prior experience in numerical experiments, the following nudging coefficients have been used:

- Upper-air wind fields: 5. 0E-4s^{-1} for Domain 1 (36km), and 2. 5E-4s^{-1} for Domain 2 (12km);
- Upper-air temperature fields: 1.0E-5s^{-1} for both Domains;
- Surface winds: 5. 0s^{-1}E-4s^{-1} for Domain 1, and 2.5E-4s^{-1} for Domain 2; and
- Surface temperature and moisture: not nudged due to instability consideration.

ASSESSMENT

This assessment covers the period of May through September 2002.

National Weather Service (NWS) and CASTNet data – Surface temperature, Wind Speed, and Humidity

NWS (TDL) and CASTNet (www.epa.gov/castnet/)surface measurements of temperature, wind speed, and humidity (note there were no humidity measurements for CASTNet) were used to compare with the MM5 outputs. The evaluation was performed with METSTAT program developed by Environ Corporation (www.camx.com/files/metstat.15feb05.tar.gz..When comparing to NWS data, the METSTAT interpolates the first layer MM5 (at 10m height) temperature and humidity data to a height of 2m, the level that corresponds to the NWS measurement of these parameters. However, no such interpolation was made for wind speed and direction. In the case of CASTNet surface measurements, no such changes were needed as CASTNet data were reported at a height of 10m. In this analysis, no exclusion was made for calm conditions. The reported calm winds (zero wind speed measured) were treated as is in this evaluation effort. The METSTAT calculated standard statistical measures – average, bias, error and index of agreement between the measured and predicted parameters.

Figure 2 displays the temperature and wind speed comparison of MM5 and measured data from NWS and CASTNet networks for August 2002. MM5 performance for both in magnitude and diurnal timing, temperature can be considered to be quite good for both NWS and CASTNet data, while MM5 underpredicted NWS and overpredicted CASTNet daytime wind speed, respectively. It should be pointed out that there are differences in how the meteorological information is collected and reported by the two networks as well as in MM5. The CASTNet measurements are based on hourly averaged wind speed while NWS reports 2min average at 10min before the hour, whereas MM5 predictions are reflective of the last time-step of the hour of computation. Interestingly, MM5 appears to track quite well the nighttime minimum wind speed for both networks. In the case of humidity (not shown), MM5 tracks the NWS observed humidity trend well, but MM5 missed the observed semi-diurnal cycles. Comparisons for the five months including bias and root mean square error from both NWS and CASTNet are available on request from NYSDEC.

The above assessment is based on domain-wide averages to provide an overall response of the model over the five months. Another way of assessing the model is to examine the degree of correlation between the measured and predicted parameters. Figure 3 displays such a comparison for temperature and wind speed for the NWS hourly data covering the period of May through September 2002. For the NWS data, the correlations are in the range from 0.7 to 0.8 for wind speed, above 0.96 for temperature, and in the range of 0.8 to 0.9 for humidity. CASTNet data (not shown) also exhibit similar correlation. These correlations indicate that MM5 simulation has captured both the diurnal and synoptic scale variations. Detailed plots of this comparison are available on request from NYSDEC.

Vertical Profiler – Winds

The Wind-Profiler network measurements along the U. S. East Coast (www.madis-fsl.org/cap) were used to evaluate the vertical profiles from MM5. There are twelve wind-profiler measurement stations from which data were available for comparison. For convenience of comparison, the wind-profiler measurements were interpolated to the MM5 vertical levels. The approach used was simple interpolation between two adjacent wind-profiler layers to the MM5 vertical level, and was limited to that reported by the profiler measurement. The focus of the comparison was to assess if MM5 was able to capture the measured vertical structure, and for this we used the observed Low Level Jet (LLJ) as an indicator. The comparison was performed for June, July and August 2002. In general it is found that MM5 captures the profiler measured vertical wind field structure reasonably well. Figure 4 displays an example of the MM5 and wind profiler comparison for the August 2002 episode at Richmond, VA and Concord, NH. MM5 predicted weaker LLJ winds compared to those based on the wind-profiler measurements. The detailed plots of this comparison are available on request from NYSDEC.

Cloud Cover – Satellite cloud image

Cloud information derived from satellite image data (www.atmos.umd.edu/~srb/gcip/webgcip.htm)were used to assess the MM5 prediction of cloud cover. The 0.5° by 0.5° resolution of the satellite data were interpolated into the 12km MM5 grid for comparison. The MM5 total cloud fraction was estimated by MCIP based on the MM5's low cloud, middle cloud and high cloud predictions. In general, MM5 captured the satellite cloud pattern well but underestimates the satellite cloud fraction (see Figure 5 as an example). Part of problem may due to the coarse resolution of the satellite cloud data. The detailed plots of this comparison are available on request from NYSDEC or at the following URL

Precipitation comparison

The monthly total observed precipitation data were constructed from 1/8-degree daily precipitation analysis data (http://data.eol.ucar.edu/codiac/dss/id=21.093 produced by Climate Prediction Center, based on 7,000-8,000 hourly/6-hourly gauge reports and radar). The MM5 monthly total precipitation was estimated from the MM5 predicted convective and non-convective rainfall and summed up for each month. In general, MM5 captured the observed spatial patterns in May and September, but no so well for June, July and August (See Figure 6), perhaps reflective of the summertime convective rain activities not captured by MM5. Detailed plots of this comparison are available on request from NYSDEC.

Calm Conditions

Calm conditions are defined as observed wind speed of zero knots and wind direction as 0°. It would be useful to assess how MM5 performs under observed calm conditions, because of potential pollutant buildup that could occur under such conditions. Table 1 lists the summary of the percentage of calm condition at each hour for the August 2002 from the NWS data within the 12km domain. It is apparent from the Table that the calm conditions occur primarily during the night and early morning hours, from 23Z (7 p.m. EDT) to 15Z (11 a.m. EDT) with a peak at 10Z (6 a.m. EDT). To assess MM5 performance, the observed and MM5 predicted wind speeds were divided into calm and non-calm according to observed wind speed. Figure 7 displays such a comparison of the MM5 predicted wind speed to the observed wind speed under the calm and non-calm conditions for the month of August 2002. For the "calm" group, the average wind speed for MM5 varies from 1 m/s during the night and early morning hours and over 1.5 m/s during the day. MM5 is over-predicting during observed calm wind conditions. There are local minima every 3 hours, due to the surface observed wind speed nudging in MM5. In contrast under the non-calm conditions, MM5 underpredicts by about 0.5 m/s for all hours with noticeable local maximum happening at the nudging hours. The MM5 nudging process would pull predictions toward the measured data, while the underprediction of MM5 for the non-calm conditions may due to the adopted PBL scheme in this simulation.

Summary

In this study, we performed an assessment of the MM5 simulation to real-world data, both at the surface level as well as in the vertical. While there are no specific recommended procedures identified for this assessment, similar approaches have been used elsewhere (Dolwick 2005, Baker 2004, and Johnson 2004). Traditionally, the NWS surface measurements are used for such a comparison. Since NWS data had been used through nudging processes in developing the MM5 simulation, the comparisons should not be far removed from each other. In this study, we extended the evaluation by using CASTNet measurements that were not used in the MM5 simulations. Thus comparison with CASTNet data provides for an independent assessment and should complement the comparison with NWS data. We also compared the MM5 results with the wind profiler data and cloud data derived from satellite images to diagnose if the MM5 simulation is yielding the right type of dynamics in the vertical. The analyses shows that in general, the performance of the MM5 is reasonable both at the surface and in the vertical, thereby providing confidence in the use of these data in the CMAQ simulations.

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Table 1 Measured calm and non-calm occurrences over the modeling domain during August 2002 based on NWS data

Hour	#Non-Calm	#Calm	#Total	% Calm
00Z	18209	3924	22133	17.7
01Z	16531	6026	22557	26.7
02Z	15604	6929	22533	30.8
03Z	14983	7245	22228	32.6
04Z	14309	7540	21849	34.5
05z	14073	7735	21808	35.5
06Z	13934	7949	21883	36.3
07Z	13792	8040	21832	36.8
08Z	13542	8273	21815	37.9
09Z	13542	8385	21927	38.2
10Z	13708	8591	22299	**38.5**
11Z	14139	8693	22832	38.1
12Z	15297	7690	22987	33.5
13Z	17336	5192	22528	23
14Z	18522	3439	21961	15.7
15Z	18755	2617	21372	12.2
16Z	19169	2015	21184	9.5
17Z	19555	1617	21172	7.6
18Z	19982	1430	21412	6.7
19Z	20149	1389	21538	6.4
20Z	20565	1288	21853	5.9
21Z	20518	1383	21901	6.3
22Z	20672	1556	22228	7
23Z	20231	2292	22523	10.2

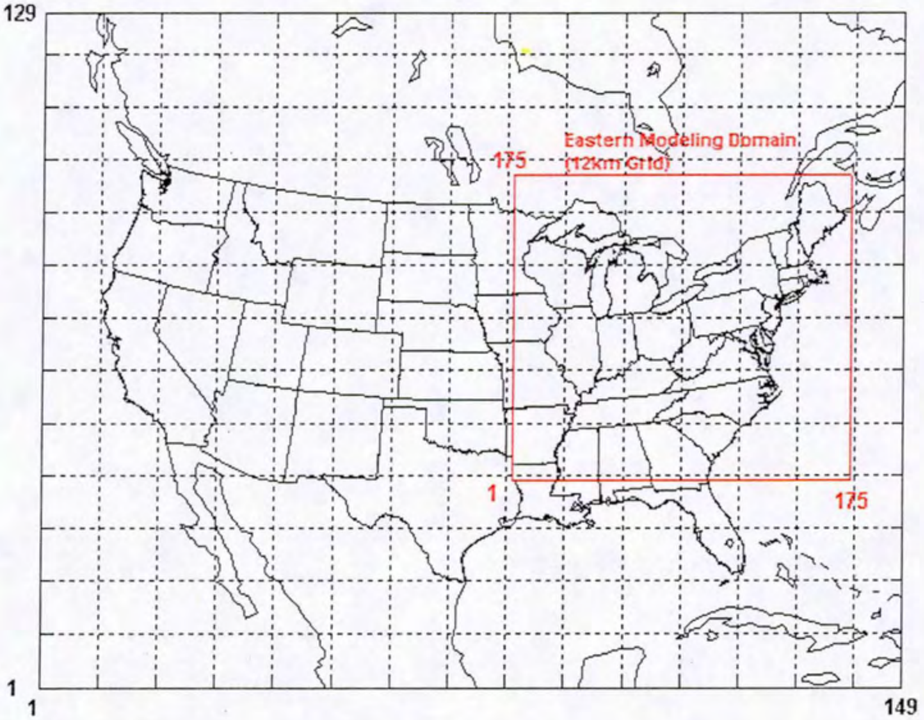


Figure 1: OTC MM5 modeling domain with areal extent of 12km and 36km grids

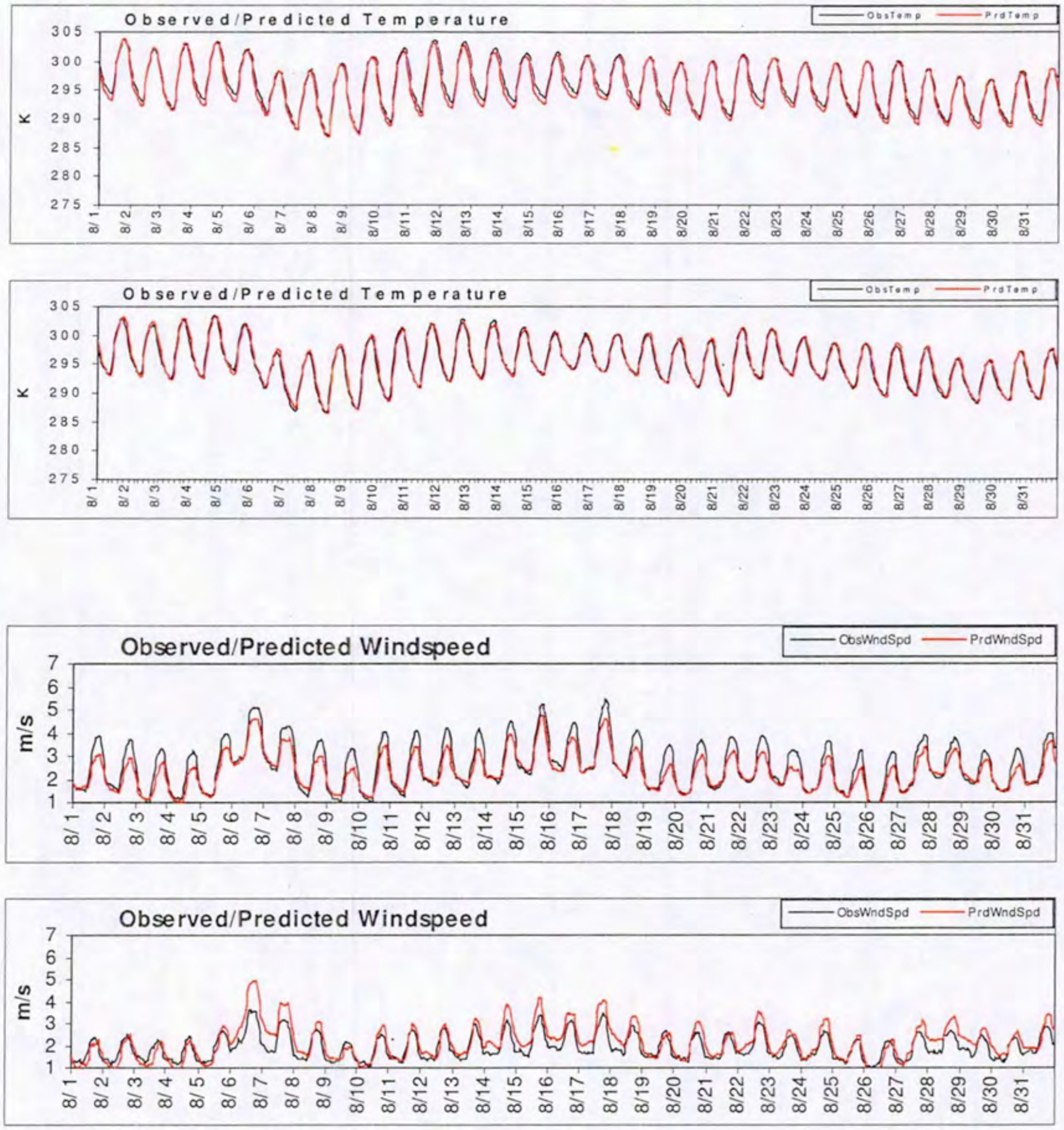


Figure 2: Temperature and Wind speed comparisons for August 2002. In each case the upper panel corresponds to comparison between MM5 and NWS data and the lower panel between MM5 and CASTNet data.

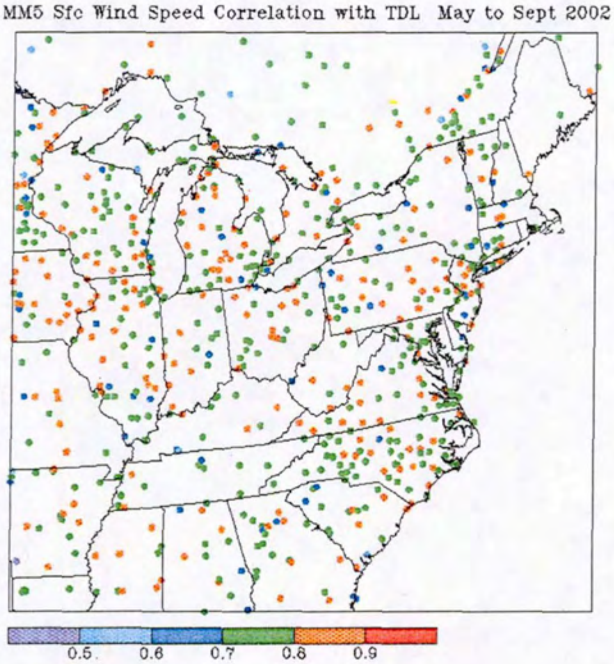


Figure 3a: Spatial correlation estimates between MM5 and NWS data for wind speed from May to September 2002

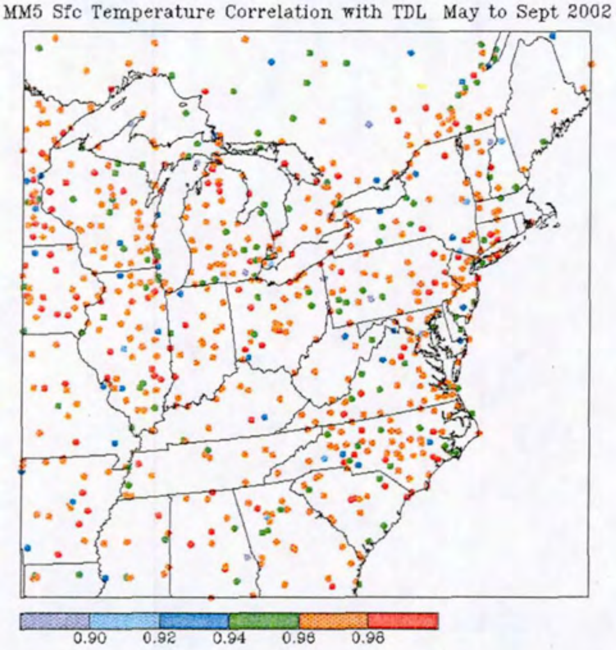
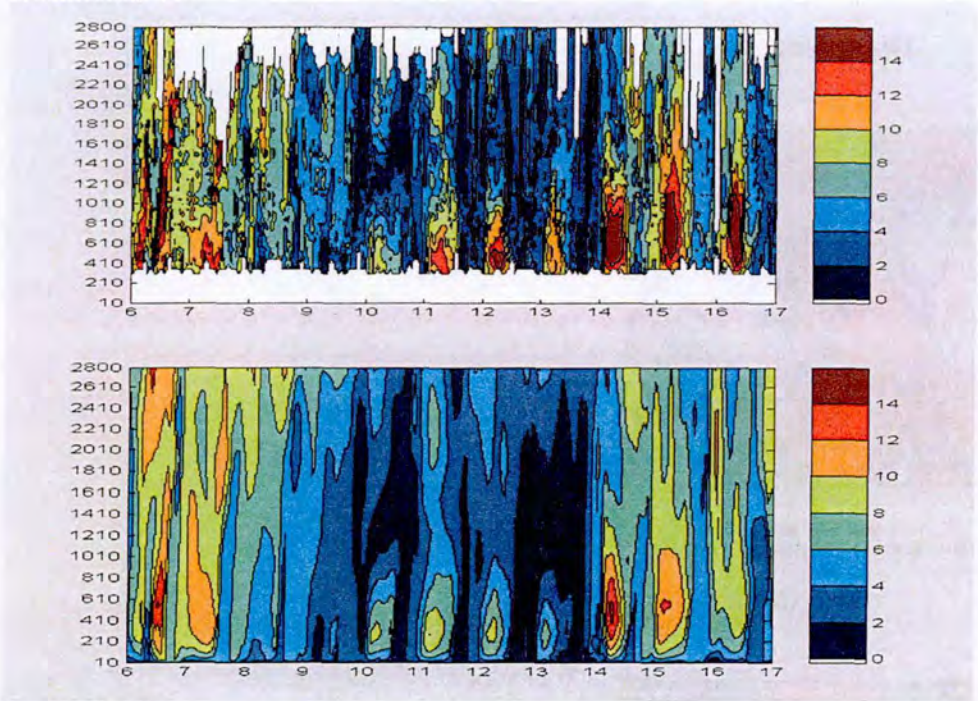


Figure 3b: Spatial distribution of correlation coefficients for Temperature between MM5 and NWS data from May to September 2002.

Richmond, VA



Concord, NH

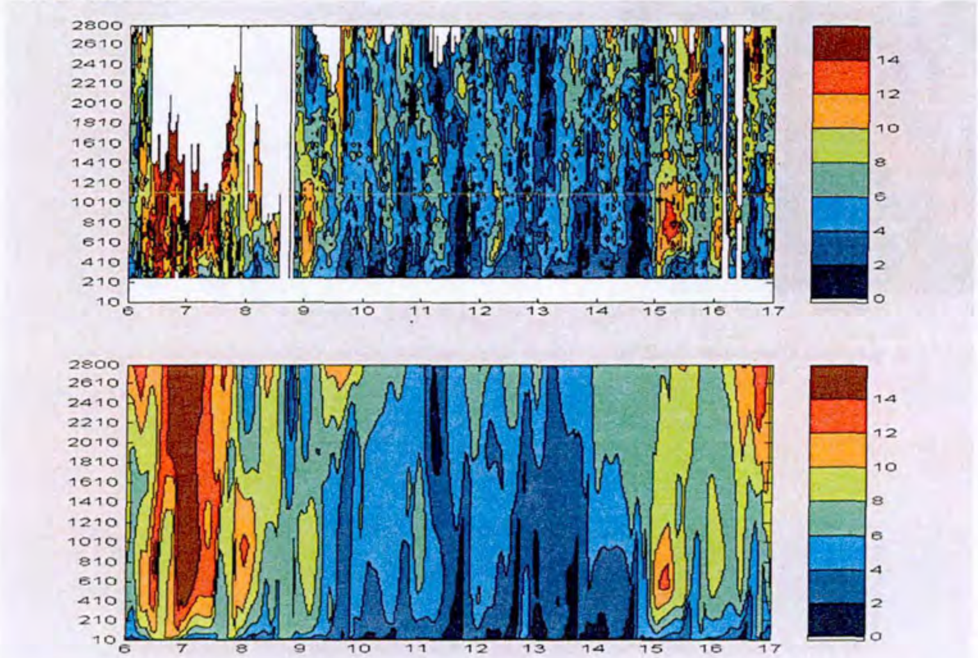
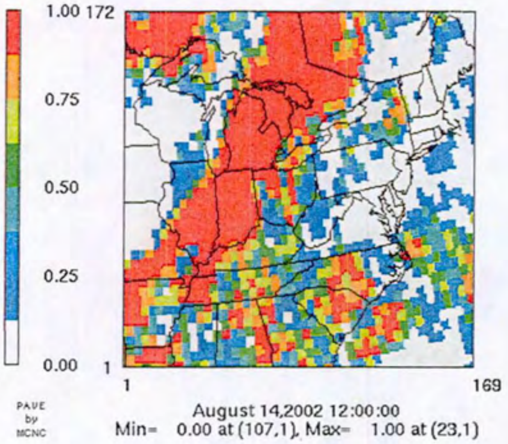


Figure 4: MM5 and Wind profiler comparison for August 6 to 17, 2002 at Richmond, VA and Concord, NH. The upper and lower panes at each station are for MM5 and profiler, respectively. The abcissa represents day and the ordinate the height (m).

Observed Cloud



MM5 Cloud

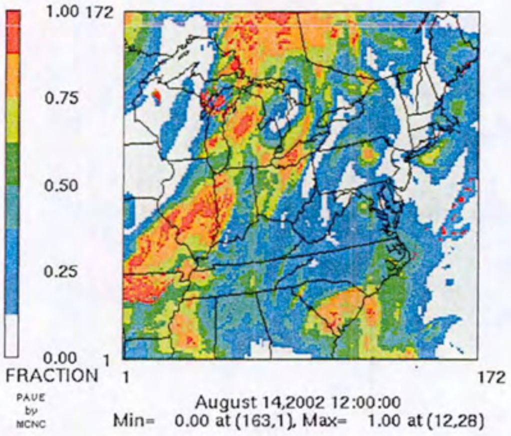


Figure 5: MM5 and Satellite cloud images for August 14, 2002 at 0700 EST

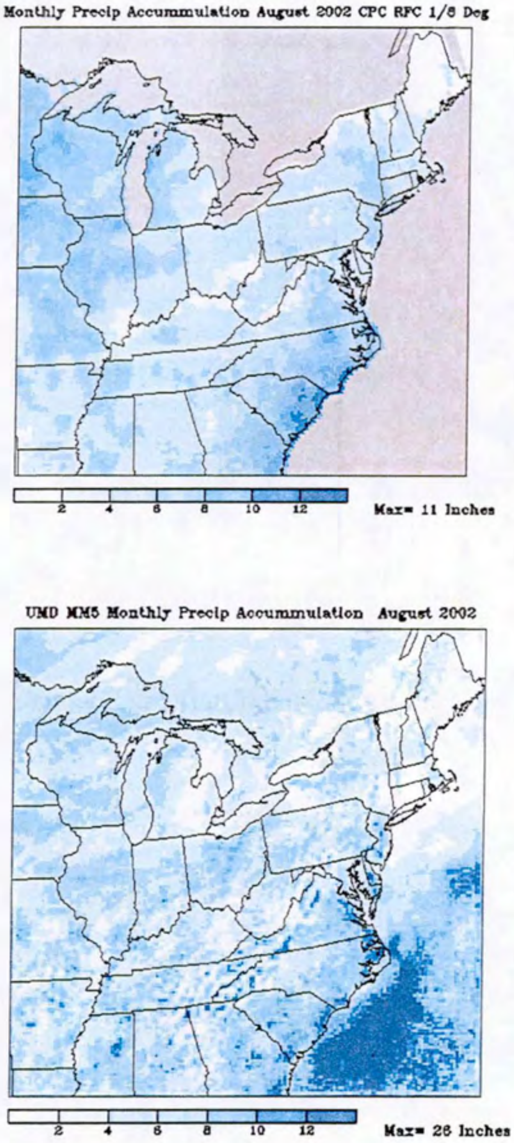


Figure 6: MM5 predicted and measured precipitation over the domain for the month of August 2002

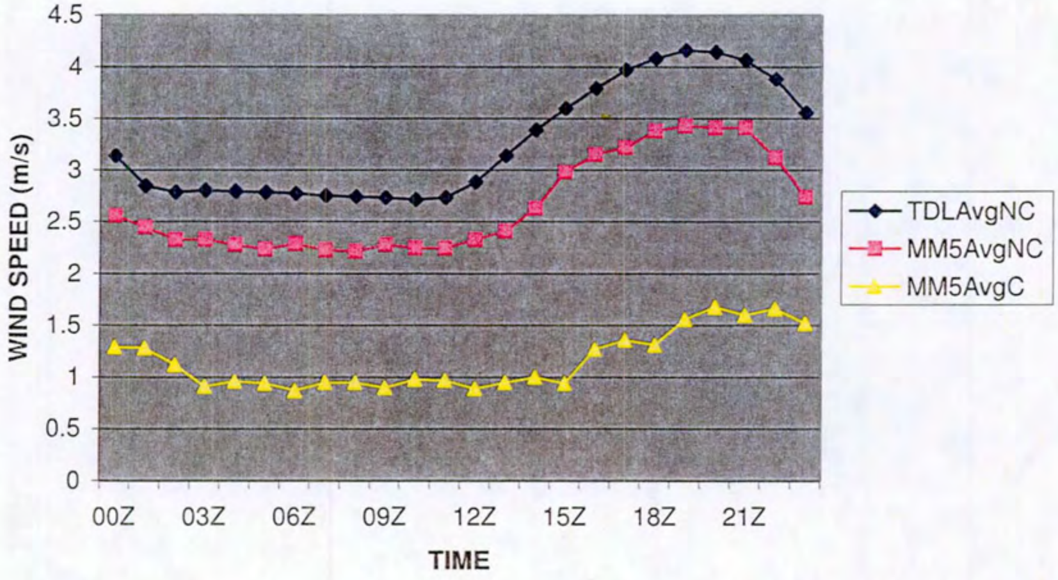


Figure 7: Comparison of averaged wind speed between MM5 and observed under calm (C) and non-calm (NC) conditions.

ATTACHMENT S

NYSDEC Technical Support Document TSD-1e

TSD-1e

CMAQ Model Performance and Assessment

8-Hr OTC Ozone Modeling

Bureau of Air Quality Analysis and Research
Division of Air Resources
New York State Department of Environmental Conservation
Albany, NY 12233

February 23, 2006

Air quality model evaluation and assessment

One of the tasks that is required as part of demonstrating attainment for the 8-hr ozone NAAQS is the evaluation and assessment of the air quality modeling system that has been utilized to predict future air quality over the region of interest. As part of the attainment demonstration, the SMOKE/CMAQ modeling system was applied to simulate the pollutant concentration fields for the base year 2002 emissions with the corresponding meteorological information. The modeling databases for meteorology using MM5 (TSD-1a), the emissions using SMOKE (TSD-1b and TSD-1c), and application of CMAQ (TSD-1d) provides simulated pollutant fields that are compared to measurements, in order to establish the credibility of the simulation. In the following sections a comparison between the measured and predicted concentrations is performed and results are presented, demonstrating on an overall basis the utility of the modeling system in this application.

The results presented here should serve as an illustration of some of the evaluation and assessment performed on the base 2002 CMAQ simulation. Additional information can be made available by request from the New York State Department of Environmental Conservation.

Summary of measured data

The ambient air quality data, both gaseous and aerosol species, for the simulation period of May through September 2002 were obtained from the following sources:

- EPA Air Quality System (AQS)
- EPA fine particulate Speciation Trends Network (STN)
- EPA Clean Air Status & Trends Network (CASTNet)
- Interagency Monitoring of PROtected Visual Environments (IMPROVE)
- Pinnacle State Park, NY operated by Atmospheric Science Research Center, University at Albany, Albany, NY
- Harvard Forest, Petersham, MA operated by Harvard University, Boston, MA
- Atmospheric Investigation, Regional Modeling, Analysis and Prediction (AIRMAP) operated by University of New Hampshire, Durham, NH
- NorthEast Ozone & Fine Particle Study (NE-OPS), led by Penn State University and other research groups in Philadelphia, PA
- Aircraft data obtained by the University of Maryland, College Park MD
- Wet deposition data from the National Atmospheric Deposition Program/National Trends Network (NADP/NTN), Atmospheric Integrated Research Monitoring Network (AIRMoN), and the New York State Department of Environmental Conservation (NYSDEC)

Measured data from sites within the Ozone Transport Region (OTR) plus the rest of Virginia were included here. The model-based data were obtained at the grid-cell corresponding to the monitor location; no interpolation was performed.

Ozone (O_3)

Hourly O_3 is measured at a large number of State, Local, and National Air Monitoring Stations (SLAMS/NAMS) across the US on a routine basis, and the data from 208 sites were extracted from the AQS database (http://www.epa.gov/ttn/airs/airsaqs/aqsweb/aqswebhome.html). Hourly O_3 concentrations from the Harvard Forest Environmental Management Site in Petersham, MA (http://www.as.harvard.edu/data/nigec-data.html); Pinnacle State Park in Addison, NY (http://www.asrc.cestm.albany.edu); and the four University of New Hampshire AIRMAP sites (http://airmap.unh.edu) were also included in this database. The EPA CASTNet program collects hourly O_3 at generally rural locations across the US (http://www.epa.gov/castnet); data from 22 sites, including two from West Virginia, were used in the model evaluation.

Fine particulate matter ($PM_{2.5}$)

The 24-hour average Federal Reference Method (FRM) $PM_{2.5}$ mass data collected routinely at SLAMS/NAMS sites across the US were extracted from AQS (257 sites). Hourly $PM_{2.5}$ mass was also included in this database, primarily extracted from AQS (54 sites). Hourly $PM_{2.5}$ mass were also taken from the Thompson Farm, NH AIRMAP site, Pinnacle State Park, and the NE-OPS site in Philadelphia, PA (http://lidar1.ee.psu.edu).

Fine particulate speciation

The 24-hour average $PM_{2.5}$ and fine particulate speciation (sulfate (SO_4), nitrate (NO_3), elemental carbon (EC), organic carbon/organic mass (OC/OM), and soil/crustal matter) from Class I areas across the US, collected every 3rd day, were obtained from the IMPROVE web site (http://vista.cira.colostate.edu/IMPROVE/Default.htm). In addition to these parameters, the EPA STN (http://www.epa.gov/ttn/amtic/speciepg.html) also reports ammonium (NH_4) to AQS; data from this network are collected every 3rd or 6th day. Data from 49 STN sites, generally in urban areas and often collocated with FRM monitors, and 21 IMPROVE sites (including Dolly Sods, WV) were used in this analysis. Organic mass is assumed to equal 1.8×OC, and soil/crustal matter is assumed to consist of oxides of Al, Ca, Fe, Si, and Ti. The STN OC data are blank-corrected by removing a monitor-specific, constant blank, and these values are available from http://www.epa.gov/airtrends/aqtrnd03/pdfs/2_chemspec0fpm25.pdf; the IMPROVE OC blanks are assumed to equal zero.

Criteria gaseous pollutants

Hourly carbon monoxide (CO; 97 sites), nitric oxide (NO; 75 sites), nitrogen dioxide (NO_2; 97 sites) and sulfur dioxide (SO_2; 134 sites) are also included in this model evaluation database. A large majority of these sites are SLAMS/NAMS monitors located primarily in urban in suburban areas, but data from the Harvard Forest, Pinnacle State Park, and AIRMAP sites are also included here.

Non-methane hydrocarbons

While there are several dozen hydrocarbon species measured routinely, for this model evaluation database the focus was on Carbon Bond IV species groups that consist of a single primary species. For this reason only ethene (C_2H_4), isoprene (C_5H_8), and formaldehyde (HCHO) concentrations were extracted from AQS. Hourly C_2H_4 and C_5H_8 data from 19 Photochemical Assessment Monitoring Stations (PAMS) sites and 24-hour average HCHO from 18 air toxics sites are included in this database.

University of Maryland aircraft data

The University of Maryland performed 144 aircraft spirals at 41 regional airport locations over 26 days from May-August 2002 (http://www.atmos.umd.edu/~RAMMPP). Spirals are approximately 20-45 minutes in duration, over which time the atmosphere from about 0-3 km is sampled. The concentrations of O_3, CO, and SO_2 from these spirals were included in this database, and help provide a semi-quantitative evaluation of CMAQ performance above the ground surface. Minute average aircraft data were compared to the nearest instantaneous 3-dimensional CMAQ output.

Wet deposition

The NADP (http://nadp.sws.uiuc.edu) collects wet deposition samples across the US, through the NTN and the AIRMoN. Weekly wet deposition samples are collected by the NTN, while daily or event-based samples were collected by the AIRMoN. The NYSDEC (http://www.dec.state.ny.us) also collects weekly wet deposition samples independently from the NADP. The wet deposition of SO_4^{2-}, NO_3^-, and NH_4^+ from 43 NADP/NTN sites, 7 NADP/AIRMoN sites, and 19 NYSDEC sites are included in this model evaluation database.

Evaluation of CMAQ predictions

The following sections provide model evaluation information for the above referenced pollutants over the OTR portion of the 12-km modeling domain. The statistical formulations that have been computed for each species are as follows: P_i and O_i are the individual (daily maximum 8-hour O_3 or daily average for the other species) predicted and observed concentrations, respectively; $\overline{P}$ and $\overline{O}$ are the average concentrations, respectively, and N is the sample size.

Observed average, in ppb:

$$\overline{O} = \frac{1}{N}\sum O_i$$

Predicted average, in ppb (only use P_i when O_i is valid):

$$\overline{P} = \frac{1}{N}\sum P_i$$

Correlation coefficient, R^2:

$$R^2 = \frac{\left[\sum (P_i - \overline{P})(O_i - \overline{O})\right]^2}{\sum (P_i - \overline{P})^2 \sum (O_i - \overline{O})^2}$$

Normalized mean error (NME), in %:

$$NME = \frac{\sum |P_i - O_i|}{\sum O_i} \times 100\%$$

Root mean square error (RMSE), in ppb:

$$RMSE = \left[\frac{1}{N}\sum (P_i - O_i)^2\right]^{1/2}$$

Fractional error (FE), in %:

$$FE = \frac{2}{N}\sum \left|\frac{P_i - O_i}{P_i + O_i}\right| \times 100\%$$

Mean absolute gross error (MAGE), in ppb:

$$MAGE = \frac{1}{N}\sum \left|P_i - O_i\right|$$

Mean normalized gross error (MNGE), in %:

$$MNGE = \frac{1}{N}\sum \frac{\left|P_i - O_i\right|}{O_i} \times 100\%$$

Mean bias (MB), in ppb:

$$MB = \frac{1}{N}\sum (P_i - O_i)$$

Mean normalized bias (MNB), in %:

$$MNB = \frac{1}{N}\sum \frac{(P_i - O_i)}{O_i} \times 100\%$$

Mean fractionalized bias (MFB), in %:

$$MFB = \frac{2}{N}\sum \left[\frac{P_i - O_i}{P_i + O_i}\right] \times 100\%$$

Normalized mean bias (NMB), in %:

$$NMB = \frac{\sum (P_i - O_i)}{\sum O_i} \times 100\%$$

Daily maximum 8-hour O_3 concentrations

Model evaluation statistics, based on daily maximum 8-hour average O_3 levels on those days having (1) at least 18 valid observations, or (2) fewer than 18 valid observations but the observed daily maximum O_3 concentration was at least 85 ppb, are presented here for all sites across the OTR and all of VA. The data cover the period May 15 through September 29, excluding July 6-9, when many sites across the eastern US were affected by large forest fires in Quebec. There are 208 SLAMS/NAMS sites and 28 special sites.

These model evaluation statistics were computed using two different threshold values for observed daily maximum 8-hour O_3. First, the statistics were computed using only those days when the observed daily maximum 8-hour O_3 concentration exceeded 40 ppb. Second, the statistics were computed using only those days when the observed daily maximum 8-hour O_3 exceeded 60 ppb. This latter method focuses on the highest O_3 days.

Figures 1-4 display time series of observed and predicted daily maximum 8-hour O_3 concentrations averaged over all sites across the OTR, at SLAMS/NAMS and special sites and for the daily maximum two thresholds. These averages were computed for each day considering all sites that met the corresponding threshold criteria. In general the observed and predicted composite average O_3 concentrations track each other rather well, although there was fairly substantial underprediction during the mid-August period. Also, the model performance tends to be better when the lower cutoff (40 ppb) was considered.

Figures 5-8 display spatial maps of fractional error and mean fractionalized bias for the two threshold levels. At each site the statistics were computed over the entire modeling season. Both the SLAMS/NAMS and special monitors are displayed here. In general, the model performance was better in the vicinity of urban areas and along the northeastern corridor, compared to the performance in rural areas where the model tended to underpredict daily maximum concentrations. The other statistical metrics yielded similar results to FE and MFB.

Table 1 lists the median and range in fractional error, and the mean fractionalized bias of daily maximum 8-hour O_3 calculated at each site over the season, for both observed thresholds (40 and 60 ppb), as well as all sites versus just the SLAMS/NAMS sites. Considering just SLAMS/NAMS sites, FE was always less than 32% for the 40 ppb threshold, and less than 40% for the 60 ppb threshold. Similarly, the MFB at SLAMS/NAMS sites ranged from -29 to +23% for the 40 ppb threshold, and ranged from -40 to +22% for the 60 ppb threshold. Adding the special sites did not affect the statistics substantially.

Diurnal variations of gases

Figures 9-17 display the composite diurnal variations of the species reported hourly – O_3 (SLAMS/NAMS and other/special sites, displayed separately), continuous $PM_{2.5}$, CO, NO, NO_2, SO_2, ethene, and isoprene. The average diurnal variations are for the period of May 15-September 30 – again excluding July 6-9 – considering all sites in the OTR. Note that the O_3 diurnal variations were computed from running 8-hour averages, with hours denoting the start of the 8-hour block. The number of monitors used to compute each composite diurnal variation is shown in each figure.

For O_3, the composite diurnal pattern predicted by CMAQ is fairly similar to that observed, especially at the more urban SLAMS/NAMS monitors. However, on average CMAQ predicts the daily maximum about an hour earlier than observed. For most of the other species presented here, CMAQ tends to predict two daily peaks, one morning and one late afternoon. For some species, such as $PM_{2.5}$ mass the observed concentration on a composite basis has very little diurnal variation. On the other hand, primary pollutants like CO, NO, and ethane, CMAQ exhibits qualitative agreement with the observations.

Daily average concentrations of co-pollutant trace gases

Composite daily average predicted and observed concentrations of CO, NO, NO_2, SO_2, C_2H_4, HCHO, and C_5H_8 across the OTR are displayed in Figures 18-24. Daily average concentrations of the criteria gases, C_2H_4 and C_5H_8 were computed from hourly averages, and only those days having at least 12 hours of valid observed data were considered here. The HCHO data shown here are based on 24-hour average values every 6th day. The criteria gas data cover the period May 15 – September 30, whereas the NMHC data only cover the June 1 – August 31 period, since these data are predominantly PAMS data; however, excluded from this analysis is the July 6-9 period when many sites across the eastern US were affected by large forest fires in Quebec.

Table 2 lists the median and range in mean fractionalized bias calculated at each site over the season used in this analysis. The values listed in Table 2 were computed at each site over the entire season. While the range in MFB is rather large for each species across all sites, the median MFB was below 50% for all species except C_2H_4, which is substantially overpredicted by CMAQ. It should be noted that these species can vary substantially from day to day, and days with very low modeled or observed values can contribute to high MFB.

$PM_{2.5}$ mass and speciation

Composite daily average predicted and observed concentrations of $PM_{2.5}$ mass (both daily average FRM data and continuous data), as well as major speciation –SO_4, NO_3, NH_4, EC, OM (defined here operationally as 1.8×blank-corrected organic carbon), and crustal mass (sum of oxides of Al, Ca, Fe, Si, and Ti) – across the OTR were compared in this analysis. The data cover the period May 15 – September 30, and again the July 6-9 period was excluded, when numerous sites in the eastern US were affected by large forest fires in Quebec. The continuous and FRM $PM_{2.5}$ data are shown every day, since there are ample daily FRM sites across the OTR. The speciation data included here are daily averages every third day, and consist of the largely urban EPA STN and the largely rural IMPROVE network. The two speciation networks collect $PM_{2.5}$, SO_4, NO_3, EC, OM, and crustal mass, while only the STN reports NH_4 at a sufficient number of locations.

Table 3 lists the median and range in mean fractionalized bias calculated at each site over the season used in this analysis. The values listed in Table 3 were computed at each site over the entire season. Figures 25-39 display time series of composite average observed and predicted daily concentrations; in these figures, for each day the statistics were computed using all monitors with valid data. The best qualitative agreement between observed and modeled concentrations is exhibited for $PM_{2.5}$ and SO_4. Note that in the case of crustal mass, the data from July 4 are also not included since this day is greatly affected by fireworks. On July 4, the composite average observed and predicted crustal concentrations were 4.59 $\mu g\ m^{-3}$ and 1.74 $\mu g\ m^{-3}$, respectively at the STN monitors, and 4.46 $\mu g\ m^{-3}$ and 0.99 $\mu g\ m^{-3}$, respectively at the IMPROVE monitors.

As with the gaseous co-pollutant data, there is a substantial spread in MFB across the sites. However, the median MFB for $PM_{2.5}$ mass and SO_4 was generally small (<12%) for both urban and rural sites. CMAQ tends to overpredict NO_3, more so at the IMPROVE sites. CMAQ also tends to underpredict OM at both urban and rural sites, although some of this discrepancy may be attributed to the fact that OM is operationally defined and is highly dependent on the blank correction and multiplier to account for other components of OM not directly measured. CMAQ tends to overpredict both EC and crustal mass, especially at urban sites; similar to OM, the crustal mass overprediction is related to the fact that this parameter is operationally defined.

Wet deposition of sulfate, nitrate, and ammonium

Observed and predicted wet deposition of SO_4, NO_3, and NH_4 were compared over the period May 14 – September 30. For this analysis, weekly or event-based wet deposition amounts from the NADP/NTN (43 sites), NADP/AIRMoN (7 sites), and New York State DEC (19 sites) covering the entire OTR plus all of VA and WV were integrated over the four-and-a-half months. Because the observed weekly wet deposition samples did include July 6-9, the corresponding CMAQ predictions also include this period. Table 4 lists the model evaluation statistics for integrated wet deposition of SO_4, NO_3, and NH_4 at each site over the season, while Figures 40-42 compare the observed and predicted weekly values relative to the 1:1 line.

Overall CMAQ tended to overpredict wet deposition of these ions. On a percentage basis, the overprediction was least for SO_4 and highest for NO_3. The NME, MNGE, MNB, and NMB were less than 50% for the three ions. Given that precipitation is very difficult to predict, especially during the summer months when rainfall can vary tremendously over a 12 km by 12 km area represented by this model grid, CMAQ did a rather good job reproducing seasonal wet deposition over the OTR.

Upper-air O_3, CO, and SO_2 data

The University of Maryland operated an instrumented light aircraft during the summer of 2002. On 26 days from May-August meteorological, trace gas, and particle scattering/absorption data were collected during ascent or descent spirals over 41 regional airports. In all, 144 spirals were performed from near the surface to about 3 km above ground level. For this analysis, composite average profiles of O_3, CO, and SO_2 were created over three time periods: "morning" (08-11 EST), "afternoon" (12-16 EST), and "evening" (17-19 EST). The minute average observed concentrations were aggregated into layer averages, which correspond to the lowest 15 model layers. Model layers are increasingly thick away from the surface; the surface layer is about 20 m thick while the 15th layer is about 500 m thick (and centered about 2.8 km above the ground). Figures 43-51 display the observed and predicted composite vertical profiles of O_3, CO, and SO_2 for the three time periods. In terms of profile shape, CMAQ was in good qualitative agreement for all three species above the surface during the afternoon hours. For CO, the model tends to greatly underpredict observed levels near the surface, whereas the predicted O_3 and SO_2 concentrations are closer to the respective observed values.

Summary

Various model evaluation statistics are presented here for a variety of gaseous and aerosol species in addition to O_3. In general, the CMAQ results were best for daily maximum O_3 and daily average $PM_{2.5}$ and SO_4 mass. Many other species vary tremendously over the course of a day, or from day to day, and small model over- or underprediction at low concentrations can lead to large biases on a composite basis. It is important to demonstrate that the model performs reasonably over the diurnal cycle, not just in terms of daily maximum or average values. Also, it is important to demonstrate that the model can reproduce concentrations above the ground level.

Table 1. Median and range in fractional error (FE, %) and mean fractionalized bias (MFB, %) for daily maximum 8-hour O_3 using the 40 ppb and 60 ppb observed thresholds. The values using only SLAMS/NAMS sites are boldfaced, the values using all sites are in regular font.

Metric, threshold	Range (%)	Median (%)
FE, 40 ppb	+10 to +34% **+10 to +32%**	+15% **+15%**
MFB, 40 ppb	-34 to +23% **-29 to +23%**	-6% **-6%**
FE, 60 ppb	+9 to +40% **+9 to +40%**	+15% **+15%**
MFB, 60 ppb	-40 to +22% **-40 to +22%**	-12% **-11%**

Table 2. Median and range in mean fractionalized bias (%) for daily average CO, NO, NO_2, SO_2, C_2H_4, HCHO, and C_5H8.

Pollutant	Range in MFB (%)	Median MFB (%)
CO (97 sites)	-128 to +144%	-10%
NO (75 sites)	-182 to +116%	-46%
NO_2 (97 sites)	-125 to +107%	+13%
SO_2 (134 sites)	-139 to 140%	+3%
C_2H_4 (19 sites)	+28 to +168%	+86%
HCHO (18 sites)	-66 to +96%	-13%
C_5H_8 (19 sites)	-54 to +165%	+43%

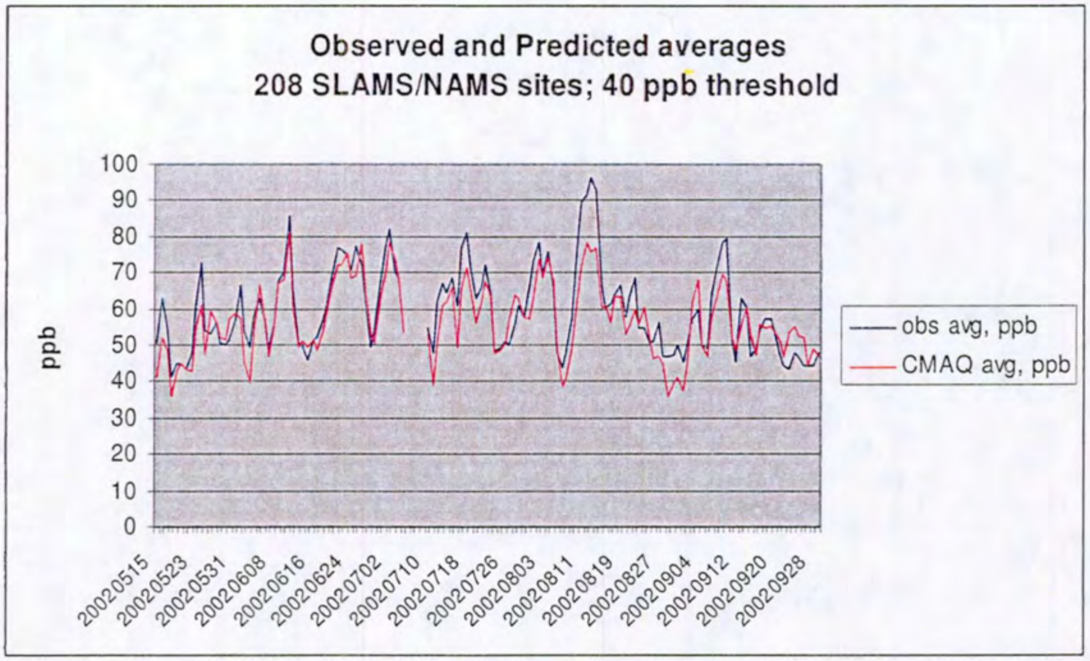
Table 3. Median and range in mean fractionalized bias (%) for daily average $PM_{2.5}$, SO_4, NO_3, NH_4, EC, and OM.

Pollutant	**Range in MFB (%)**	**Median MFB (%)**
$PM_{2.5}$ (FRM; 257 sites)	-59 to +119%	-4%
$PM_{2.5}$ (continuous; 57 sites)	-39 to +85%	+5%
STN $PM_{2.5}$ (49 sites)	-45 to +102%	-9%
IMPROVE $PM_{2.5}$ (21 sites)	-36 to +19%	-10%
STN SO_4 (49 sites)	-21 to +60%	+12%
IMPROVE SO_4 (21 sites)	-26 to +16%	-7%
STN NO_3 (49 sites)	-73 to +406%	+25%
IMPROVE NO_3 (21 sites)	-57 to +358%	+64%
STN NH_4 (49 sites)	-36 to +112%	+16%
STN EC (49 sites)	-42 to +269%	+34%
IMPROVE EC (21 sites)	-60 to +146%	-27%
STN OM (49 sites)	-82 to -25%	-58%
IMPROVE OM (21 sites)	-60 to +7%	-40%
STN crustal (49 sites)	+2 to +546%	+182%
IMPROVE crustal (21 sites)	-18 to +163%	+38%

Table 4. Model evaluation statistics for integrated wet deposition of SO_4, NO_3, and NH_4

Parameter	**SO_4**	**NO_3**	**NH_4**
Observed average, mg m^{-2}	1063	704	185
Predicted average, mg m^{-2}	946	367	117
Correlation coefficient, R^2	0.17	0.22	0.12
NME, %	34	49	48
RMSE, mg m^{-2}	490	417	109
FE, %	36	62	57
MAGE, mg m^{-2}	365	344	89
MNGE, %	36	45	46
MB, mg m^{-2}	-118	-337	-68
MNB, %	-3	-44	-28
MFB, %	-13	-61	-44
NMB, %	-11	-48	-37

Figure 1.



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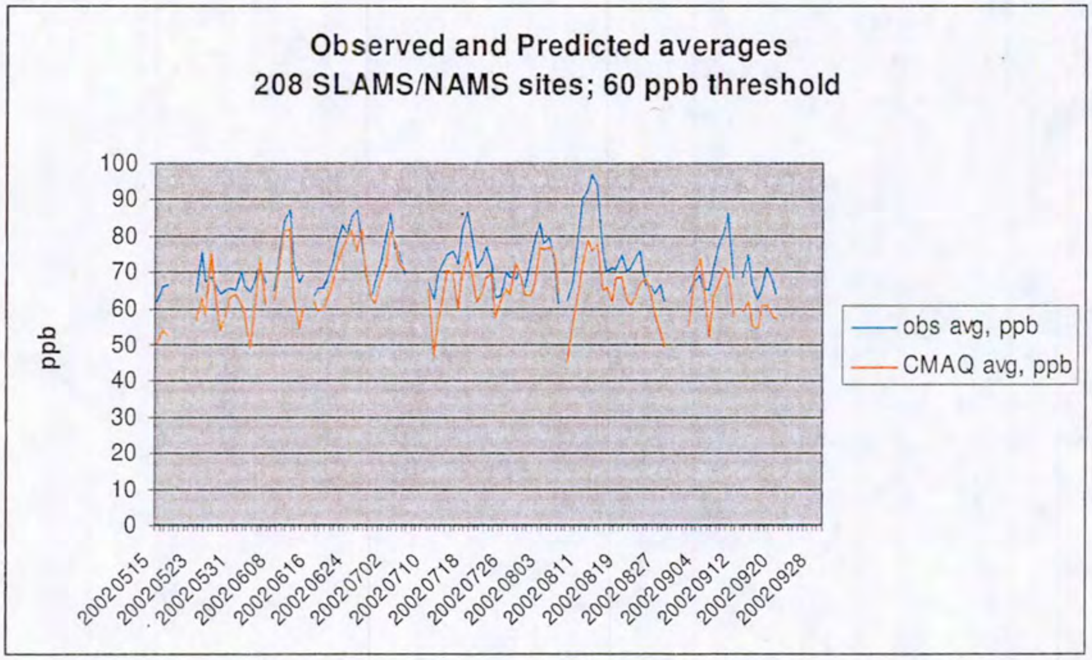

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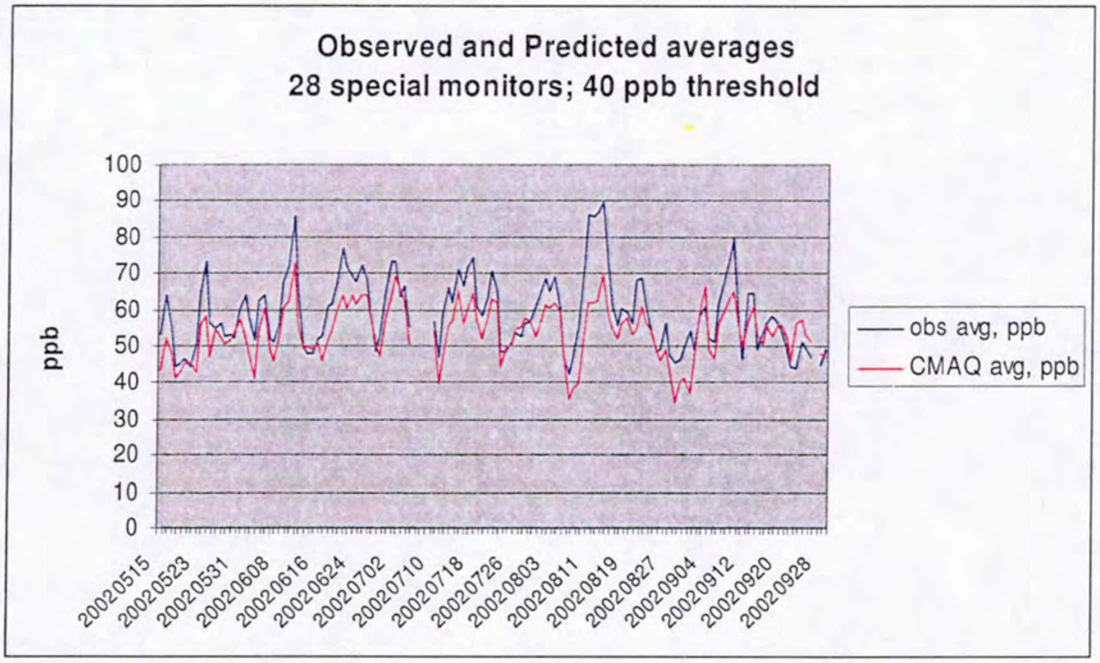

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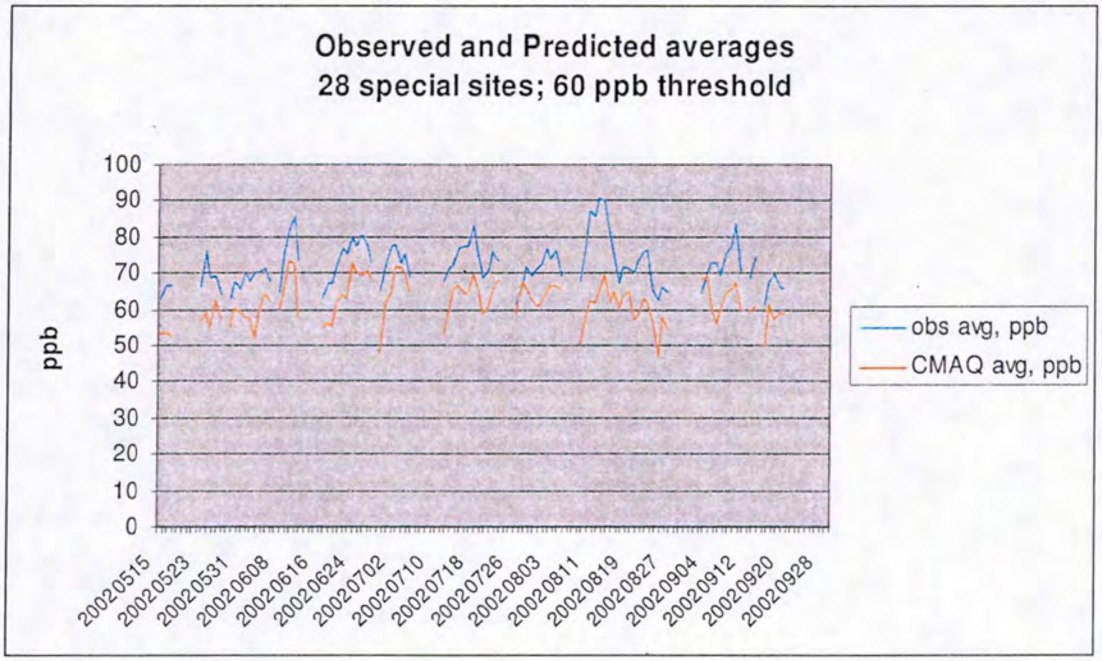

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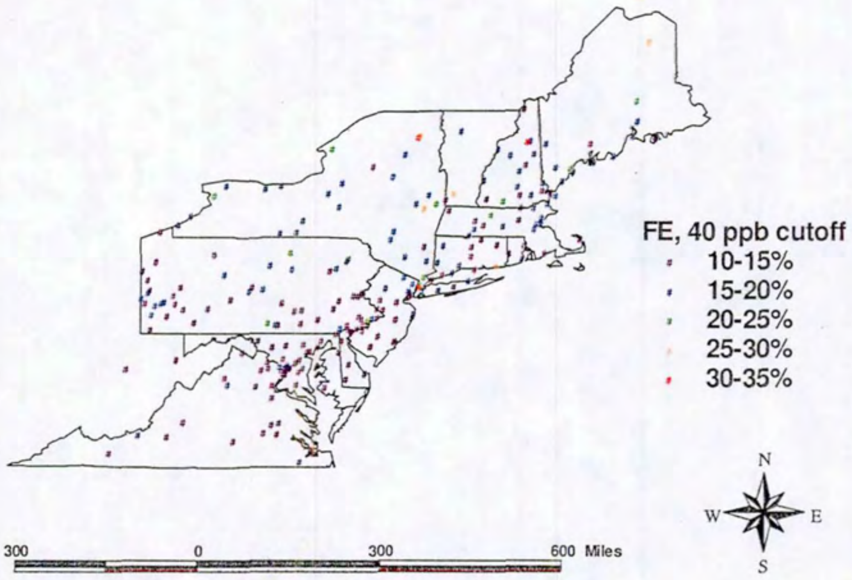

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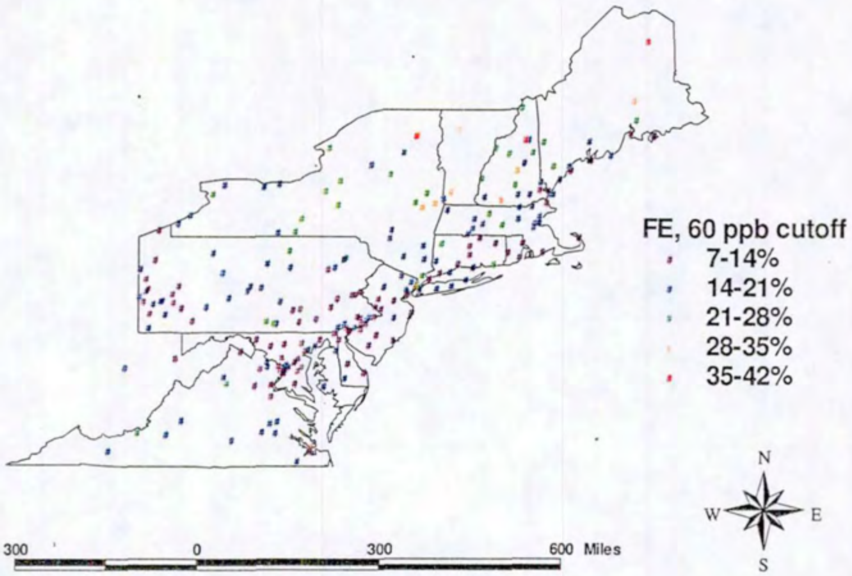

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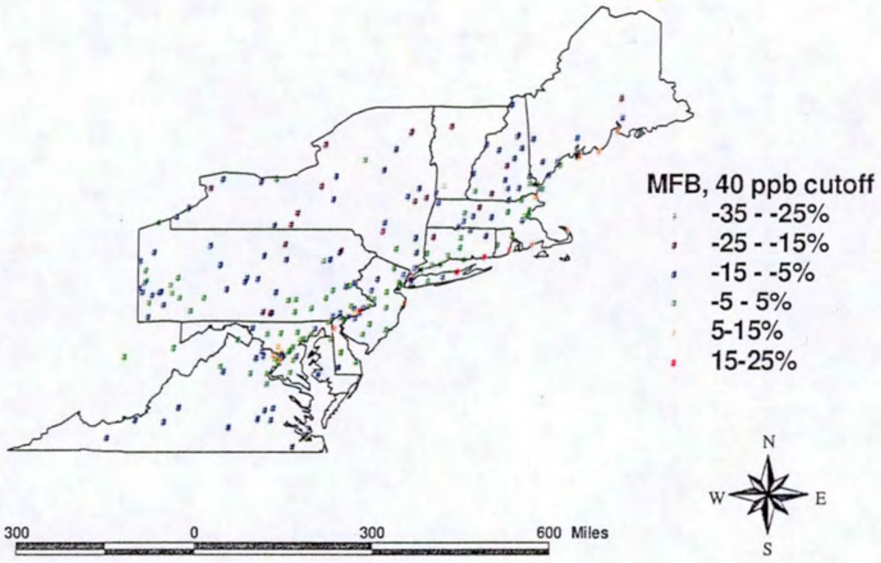

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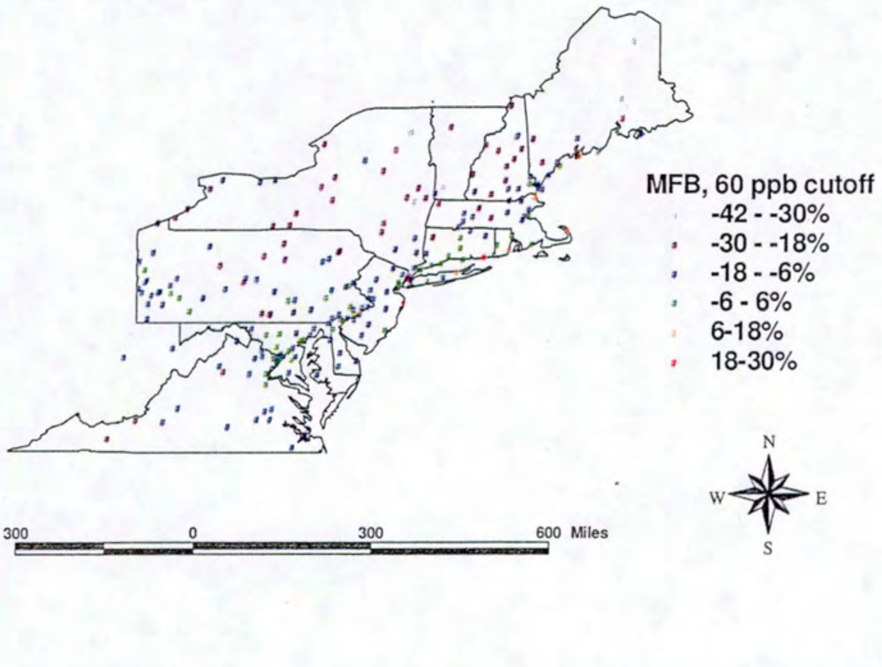

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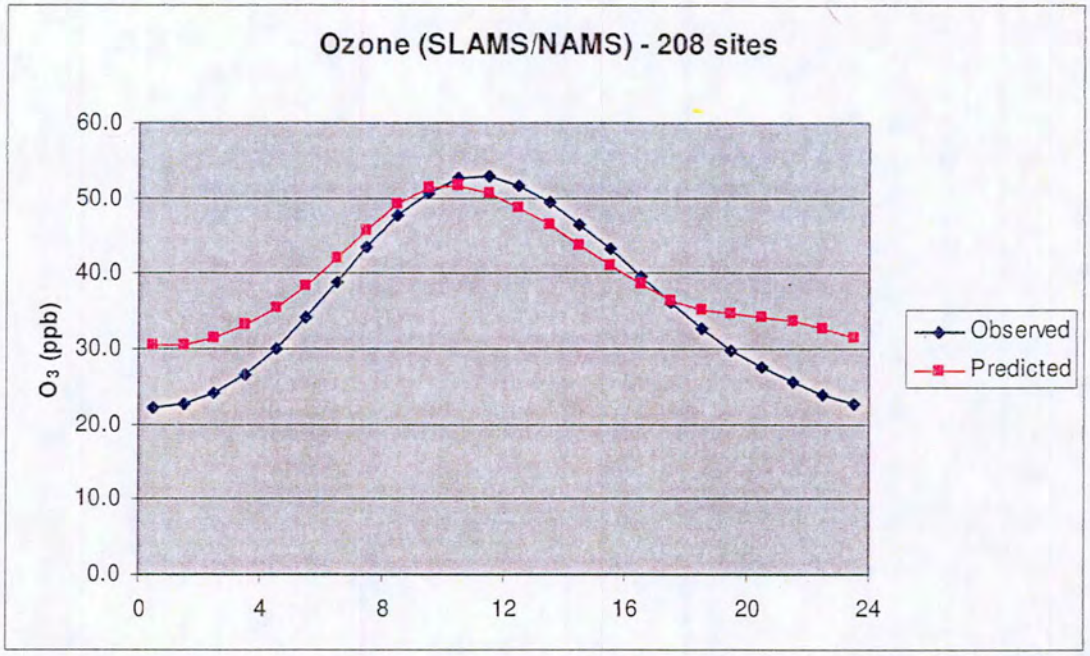

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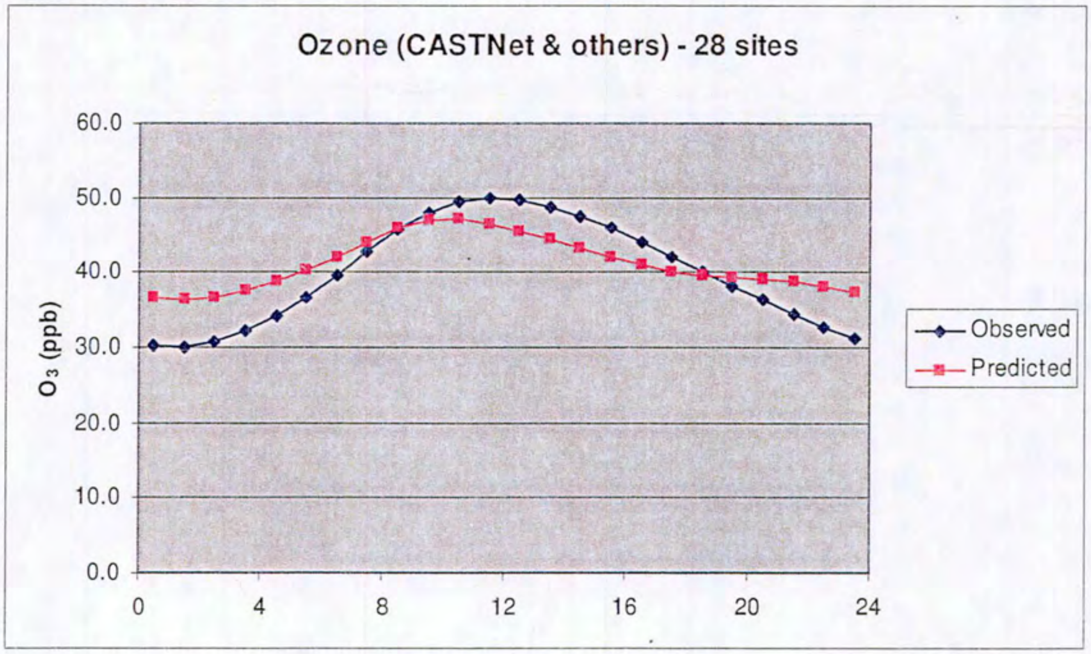

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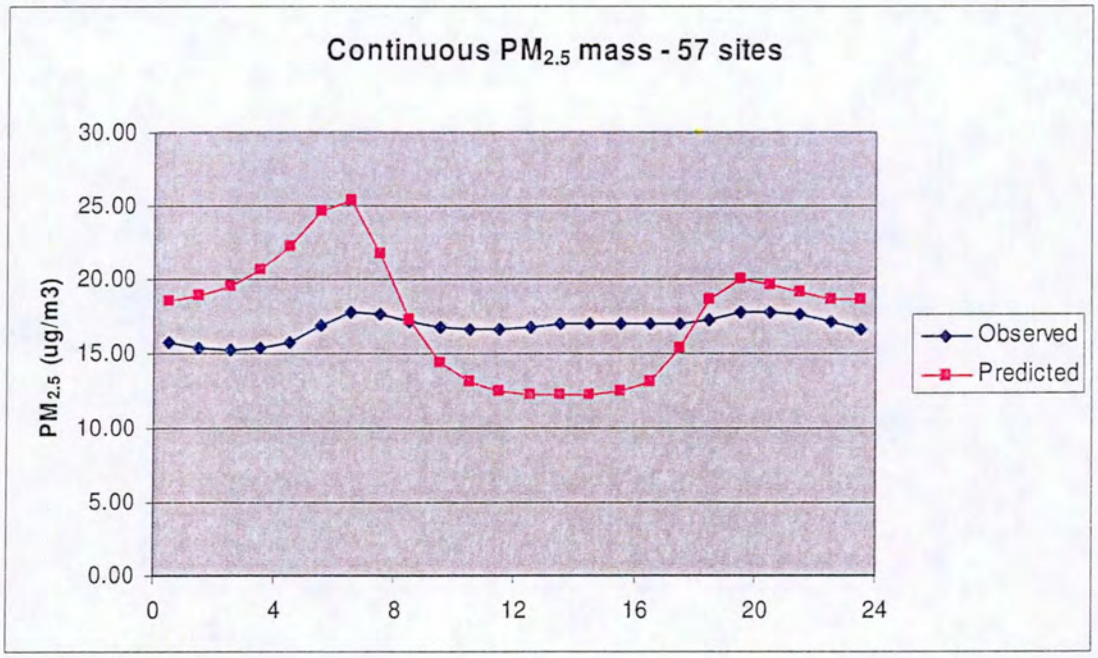

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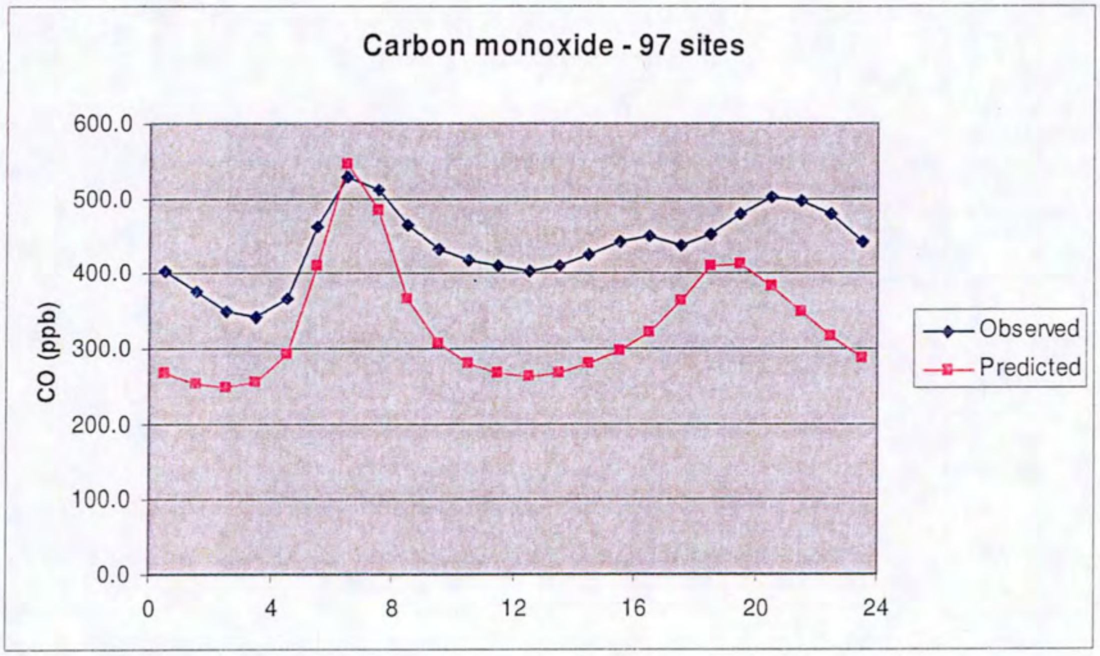

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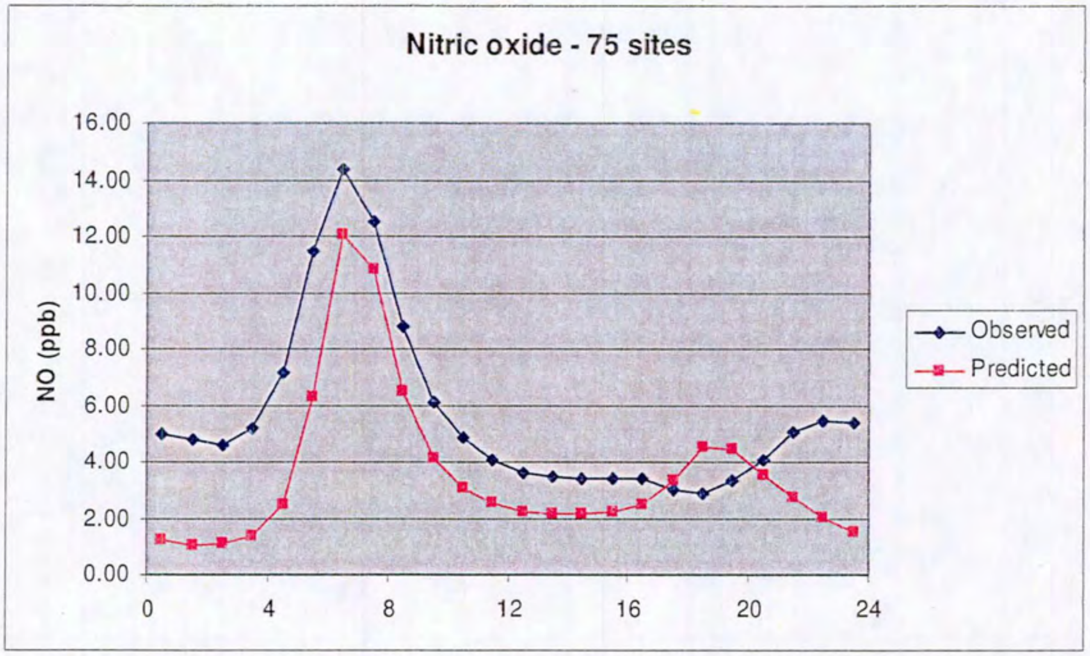

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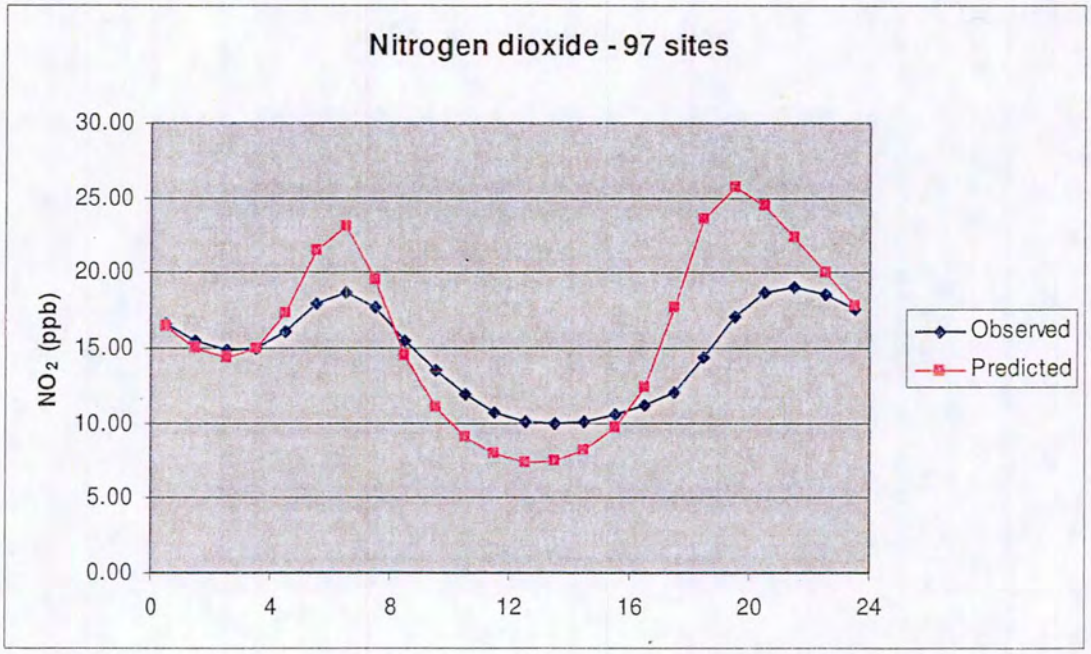

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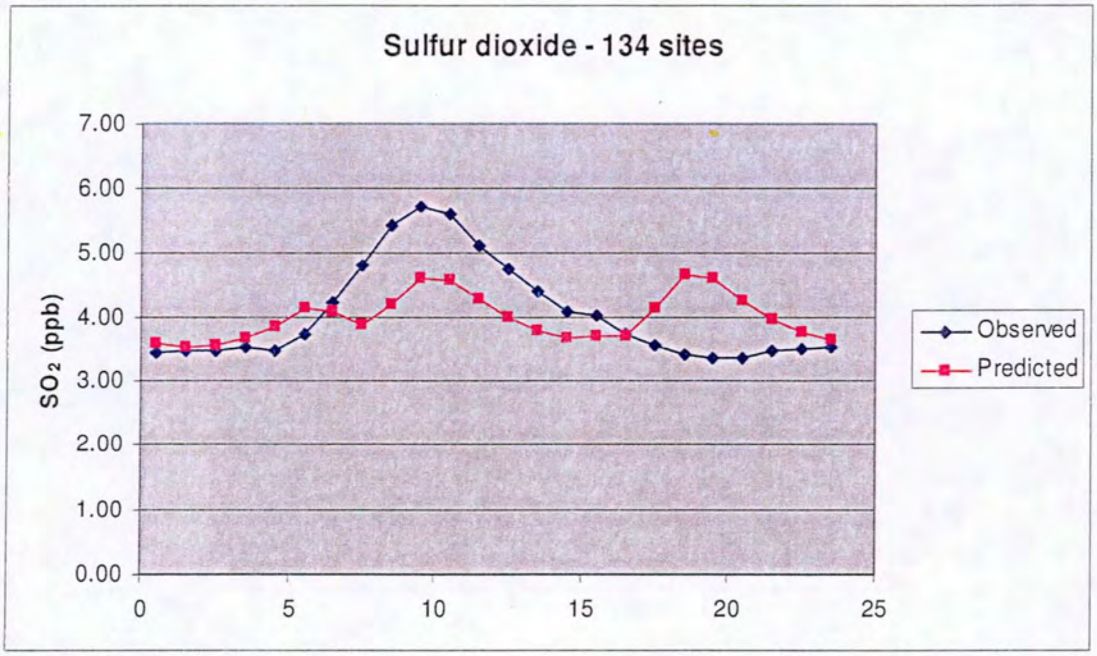

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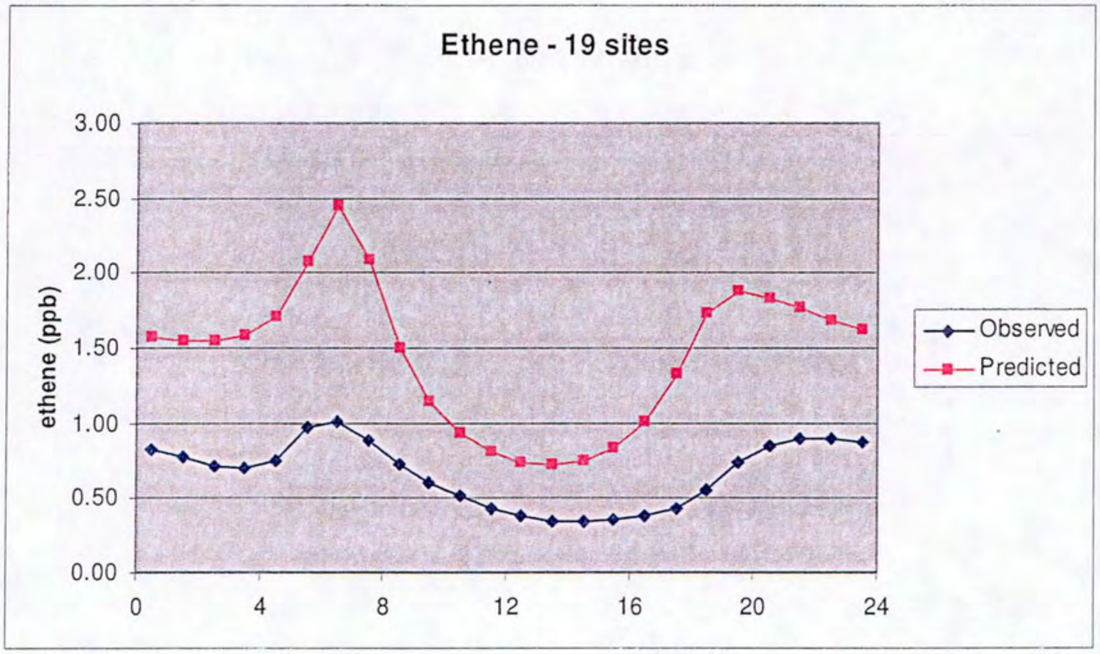

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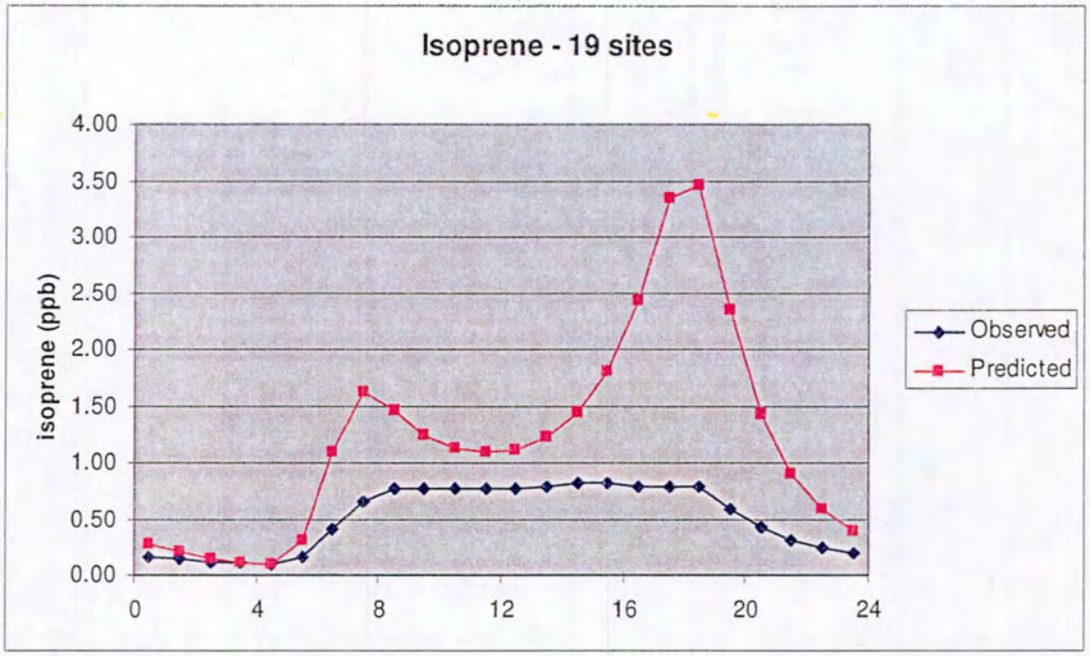

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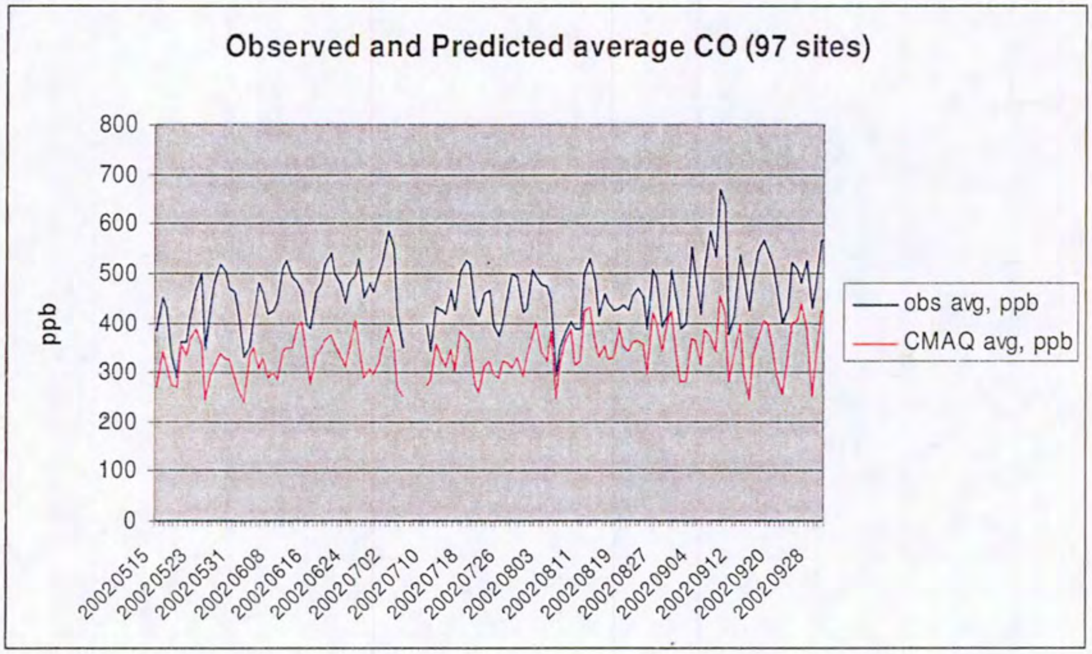

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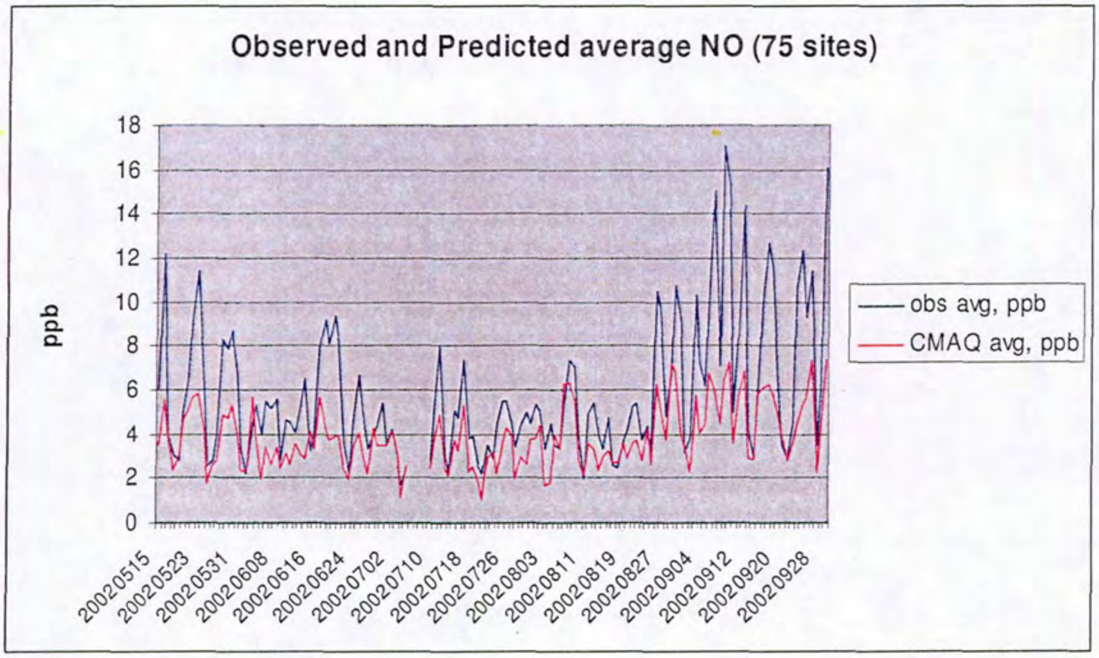

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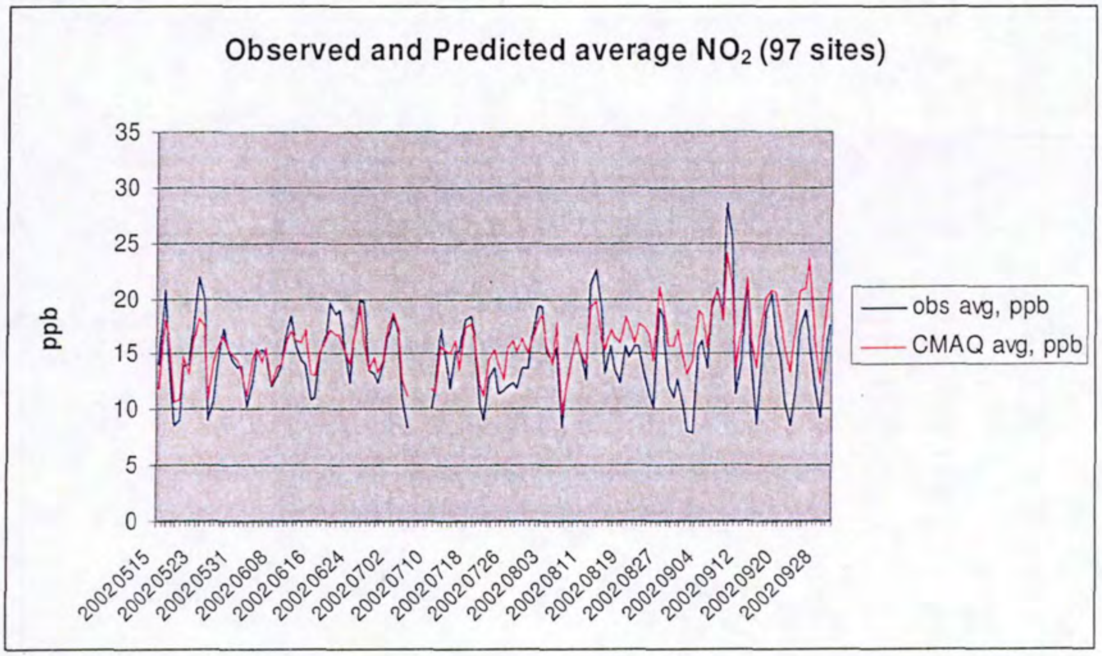

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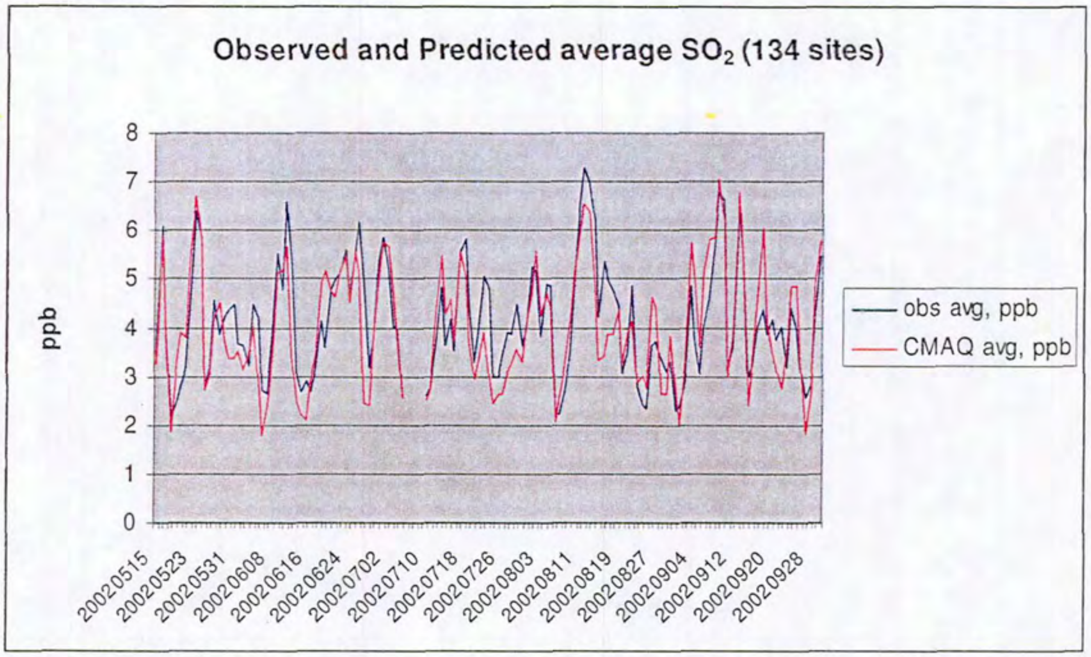

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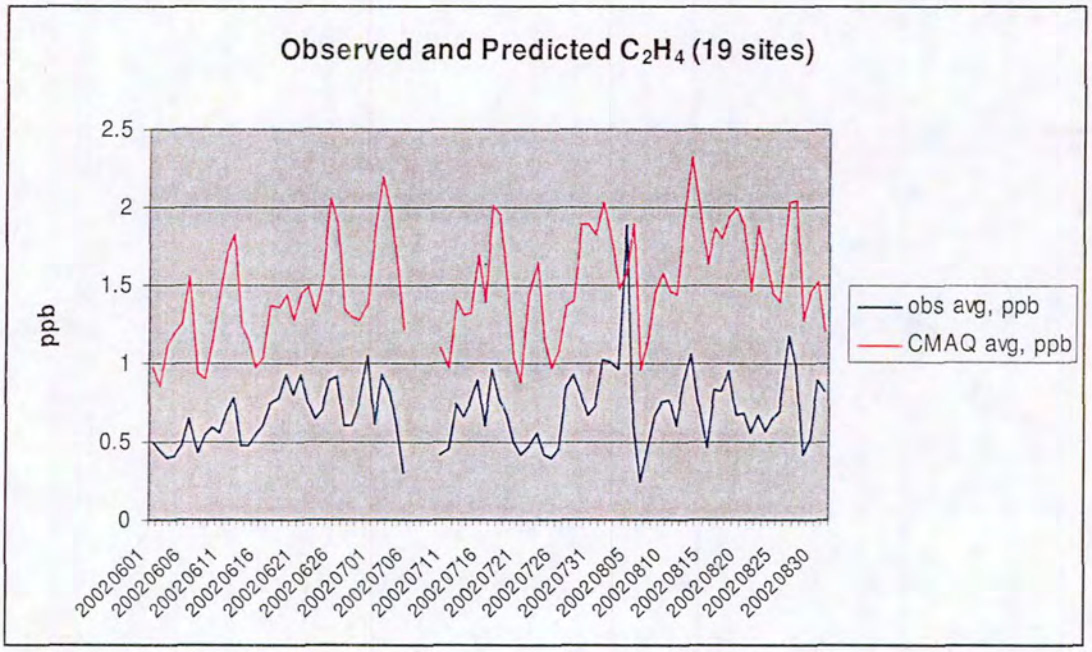

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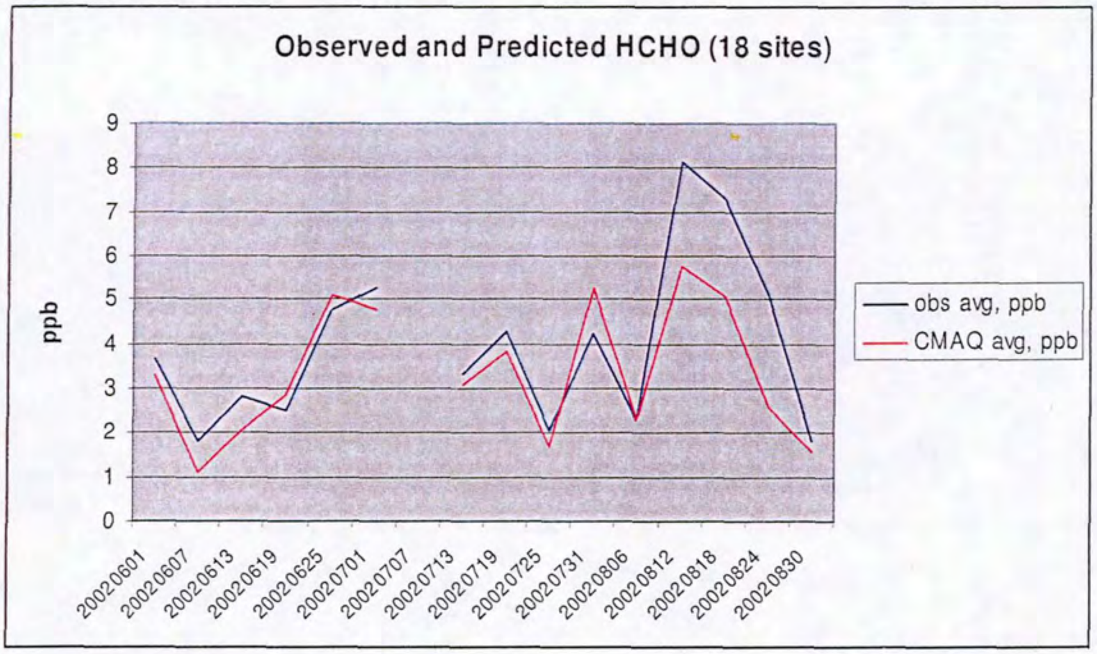

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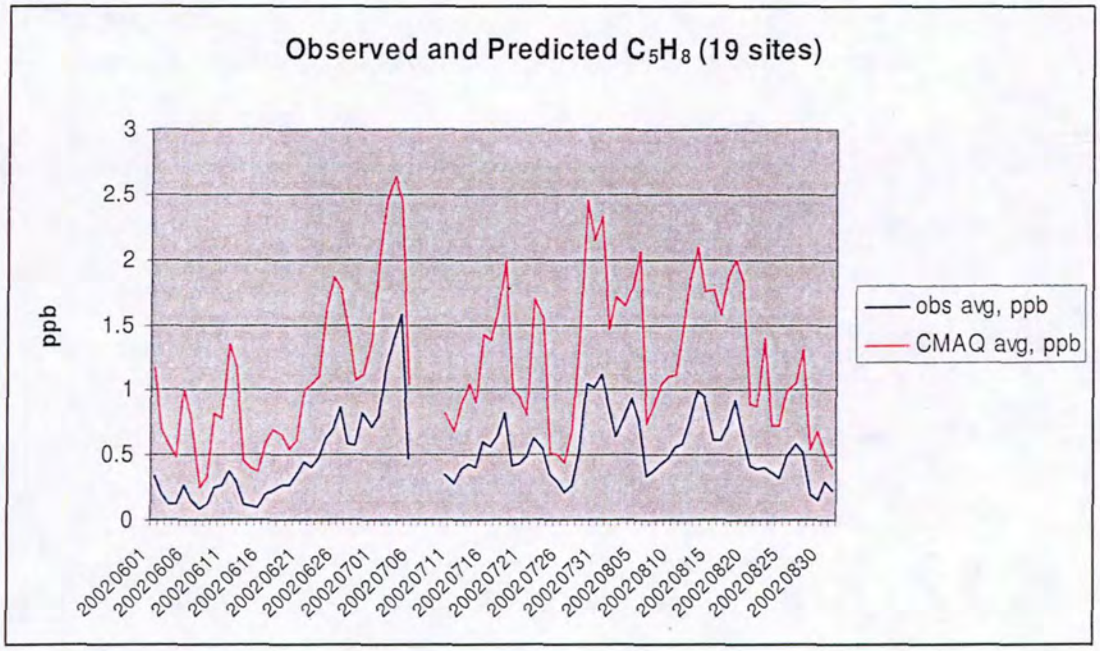

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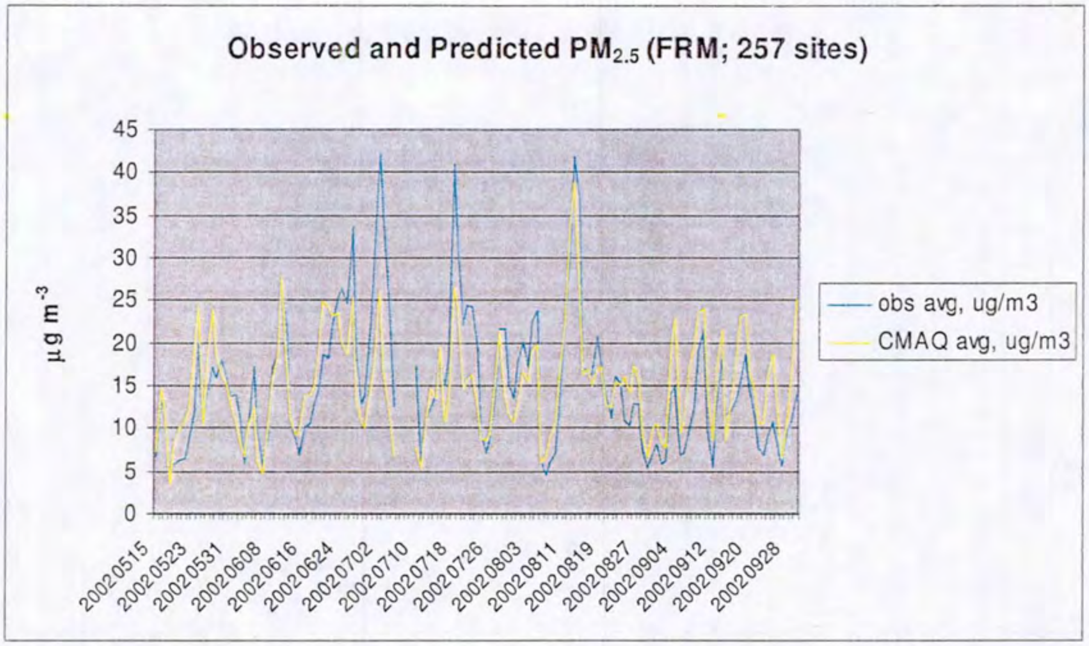

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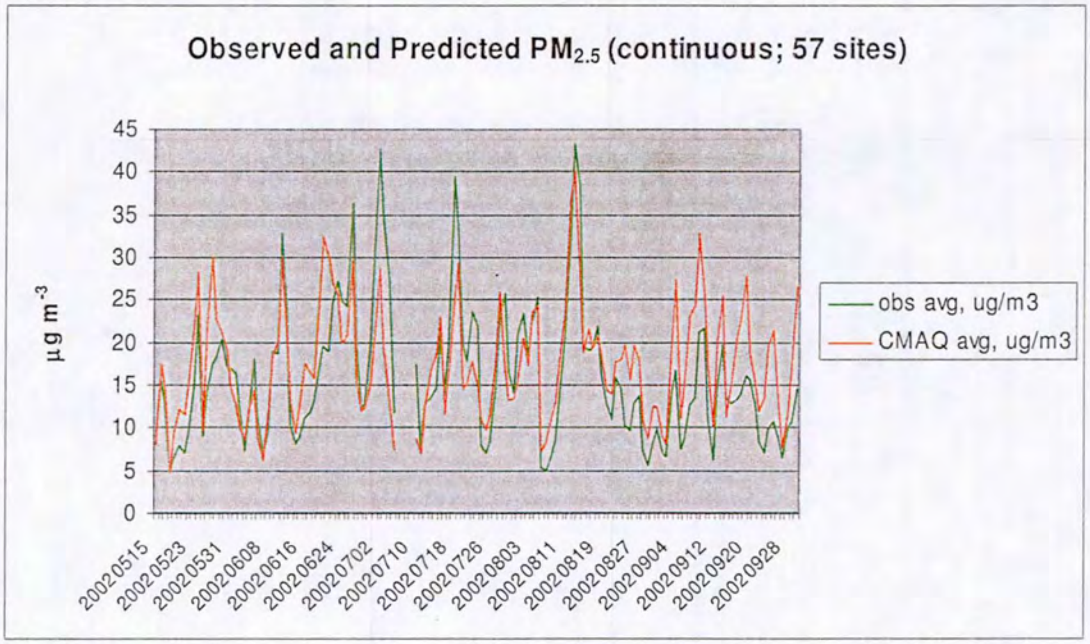

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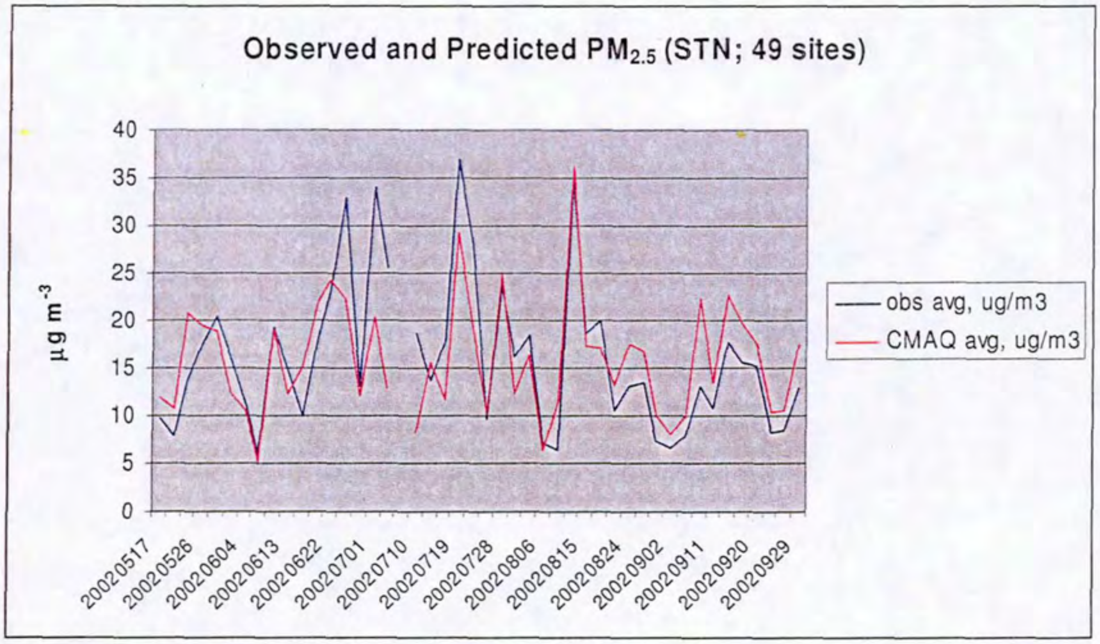

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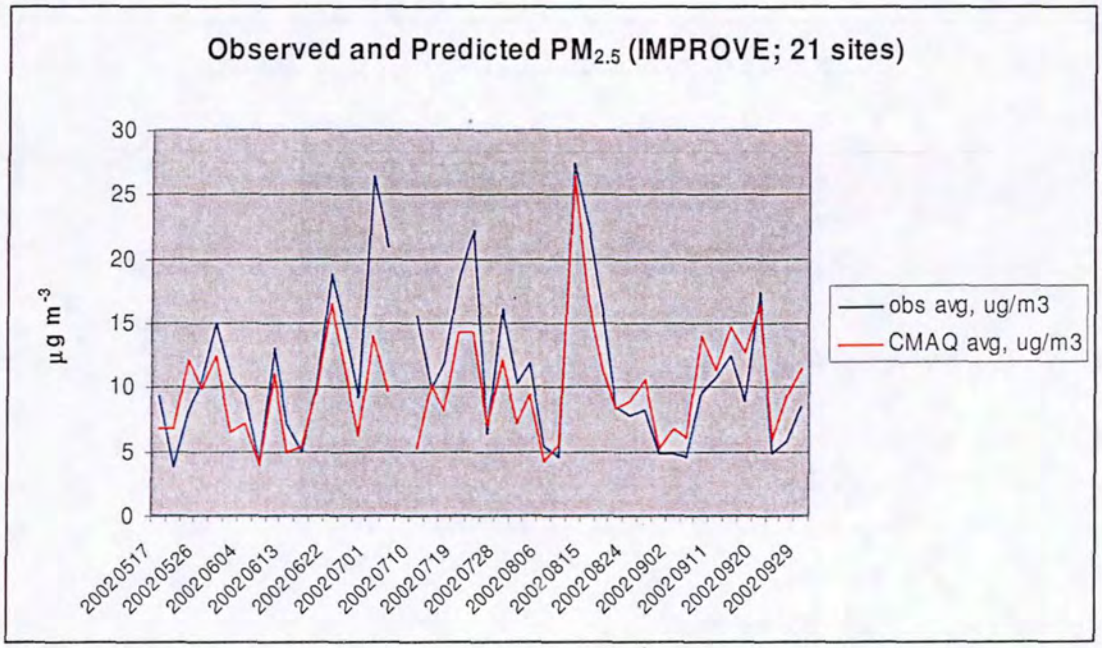

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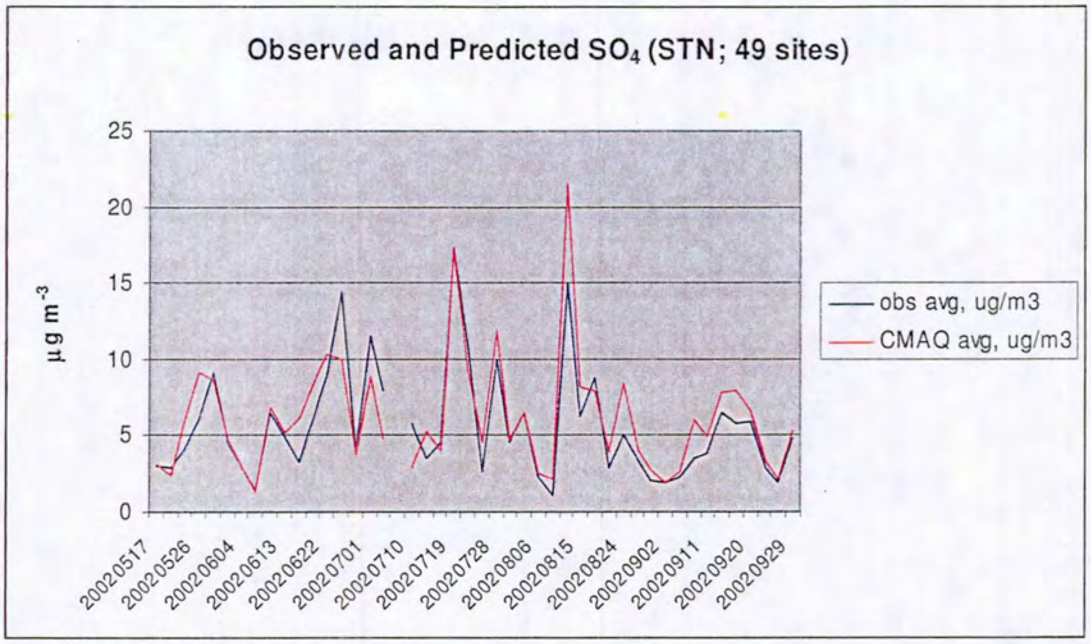

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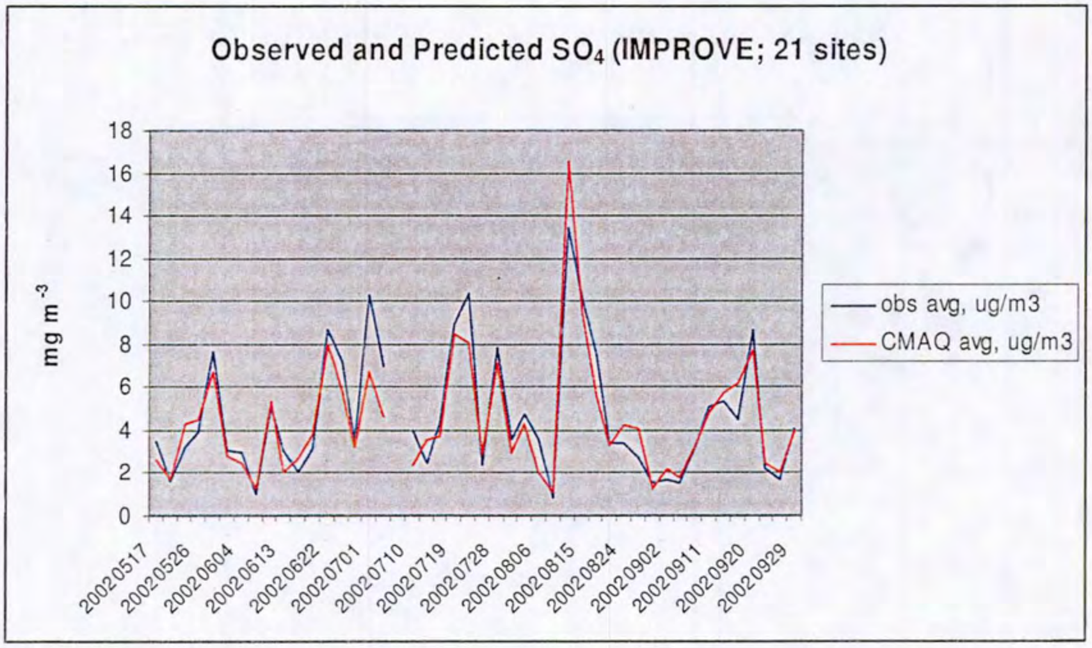

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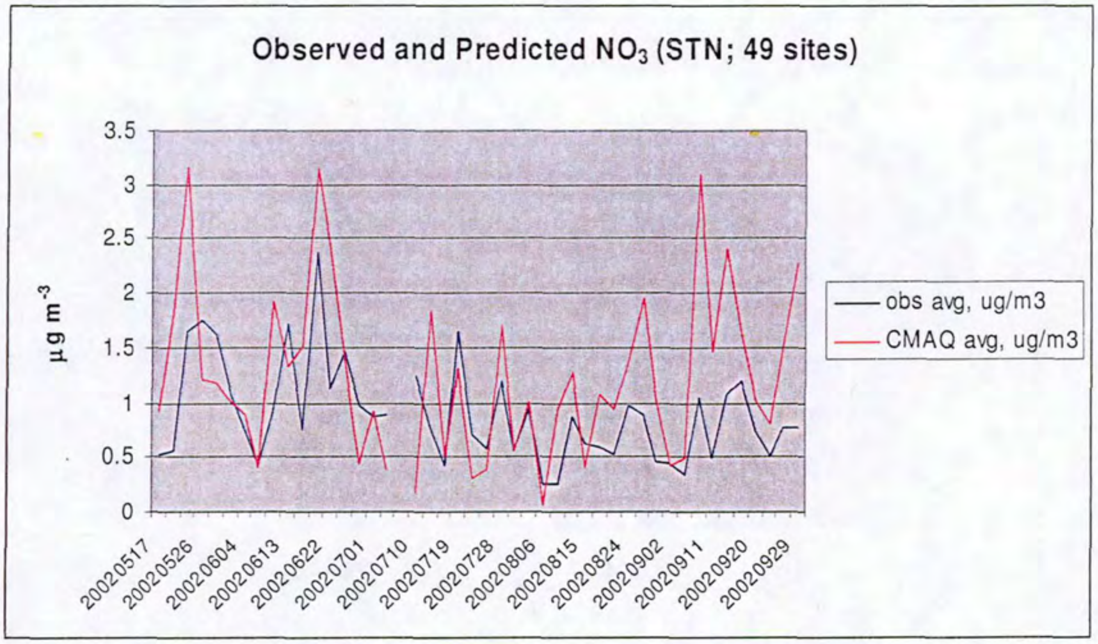

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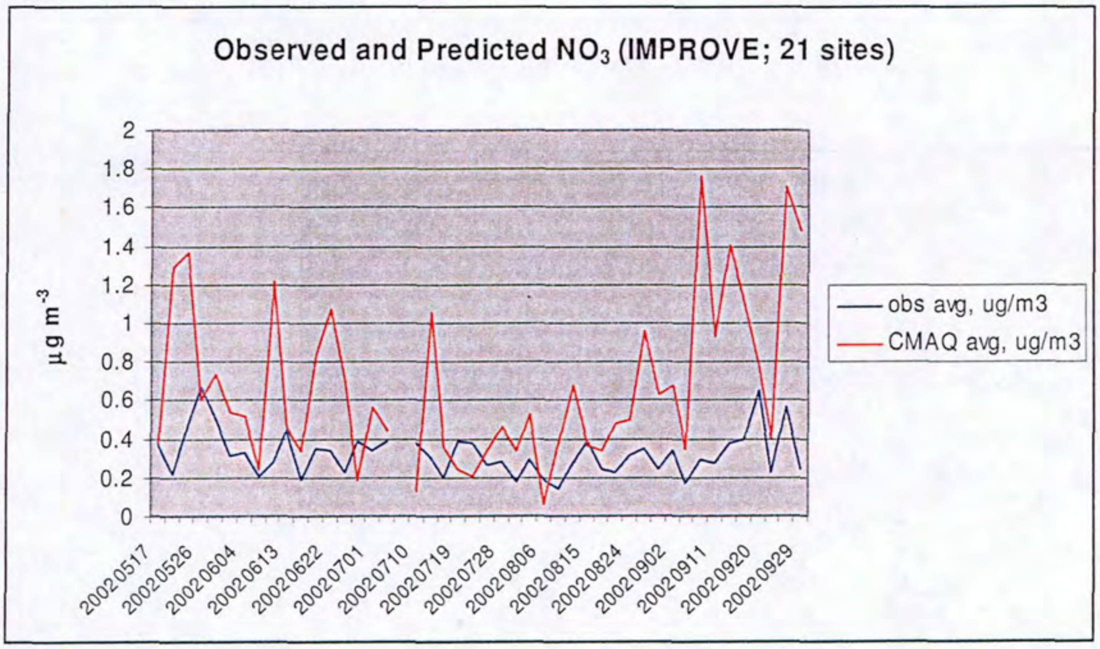

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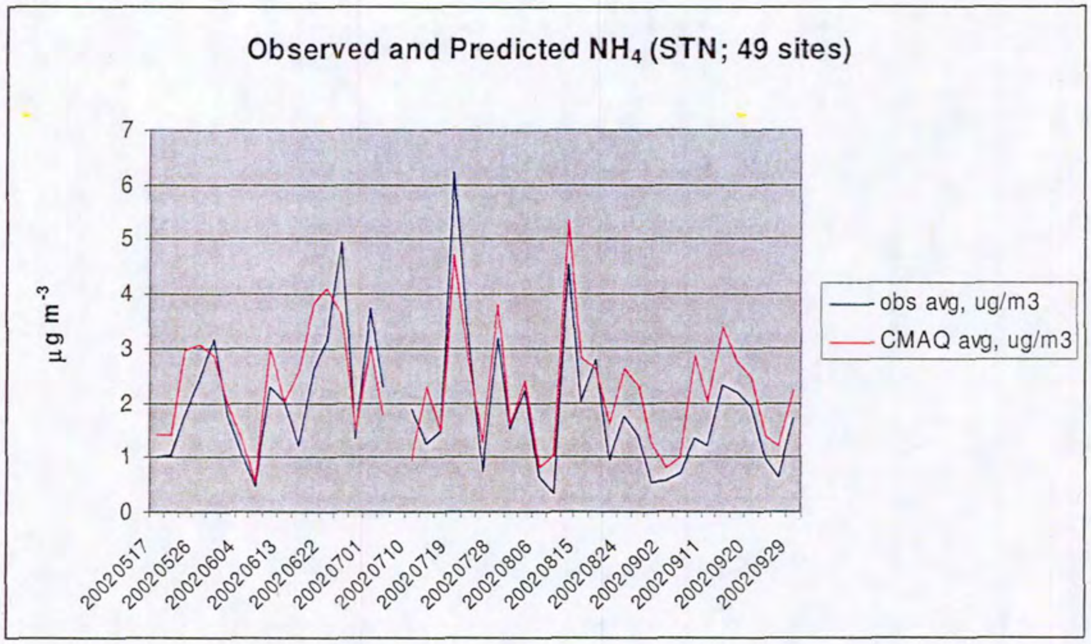

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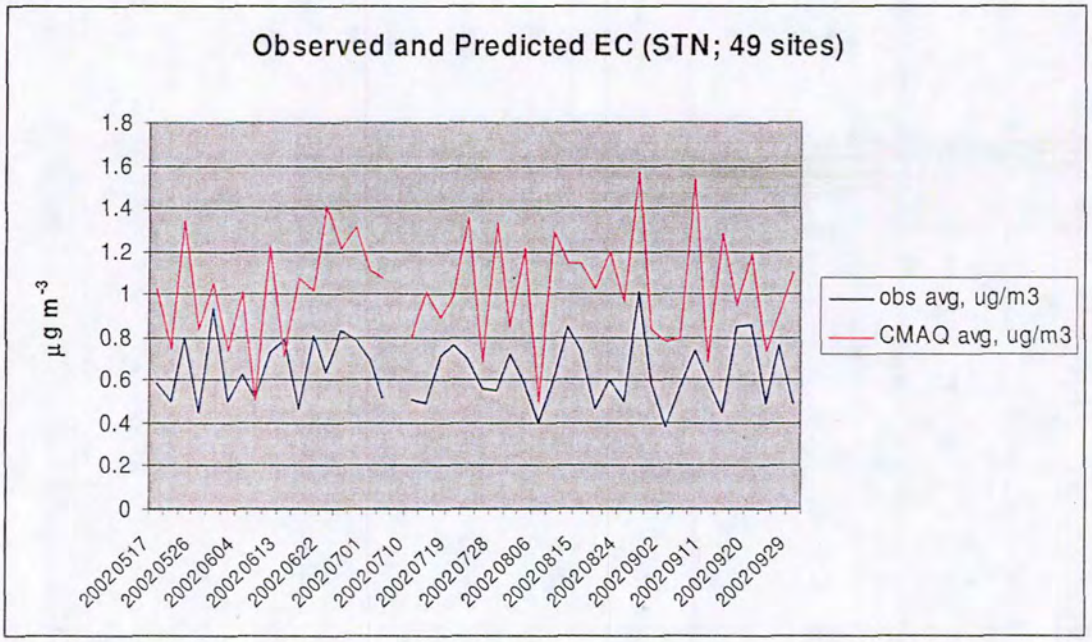

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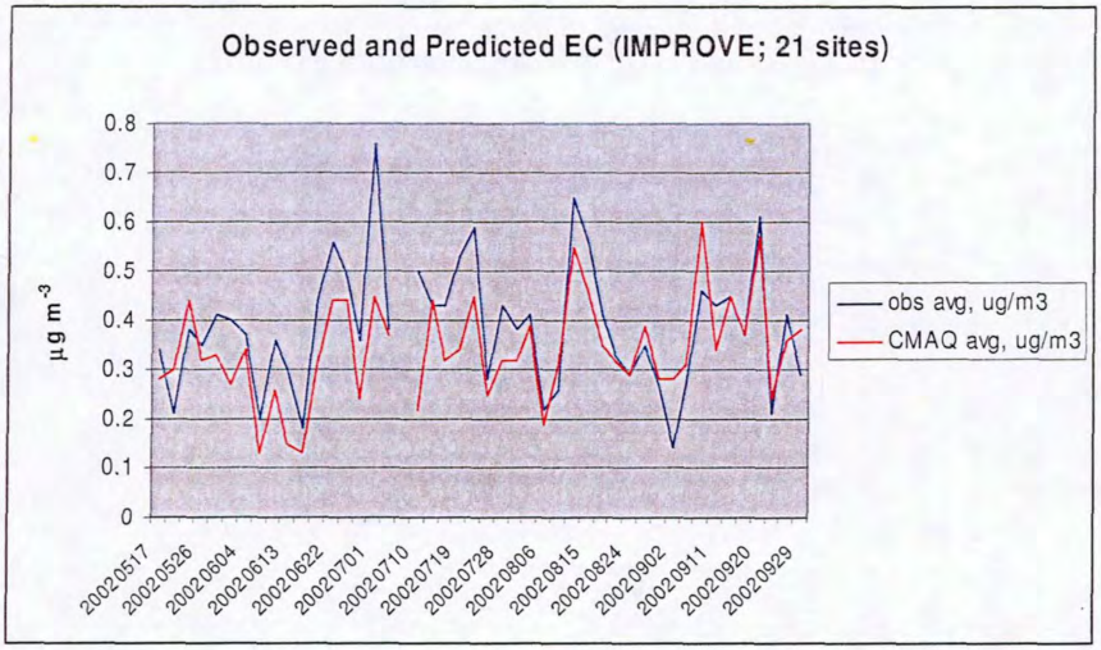

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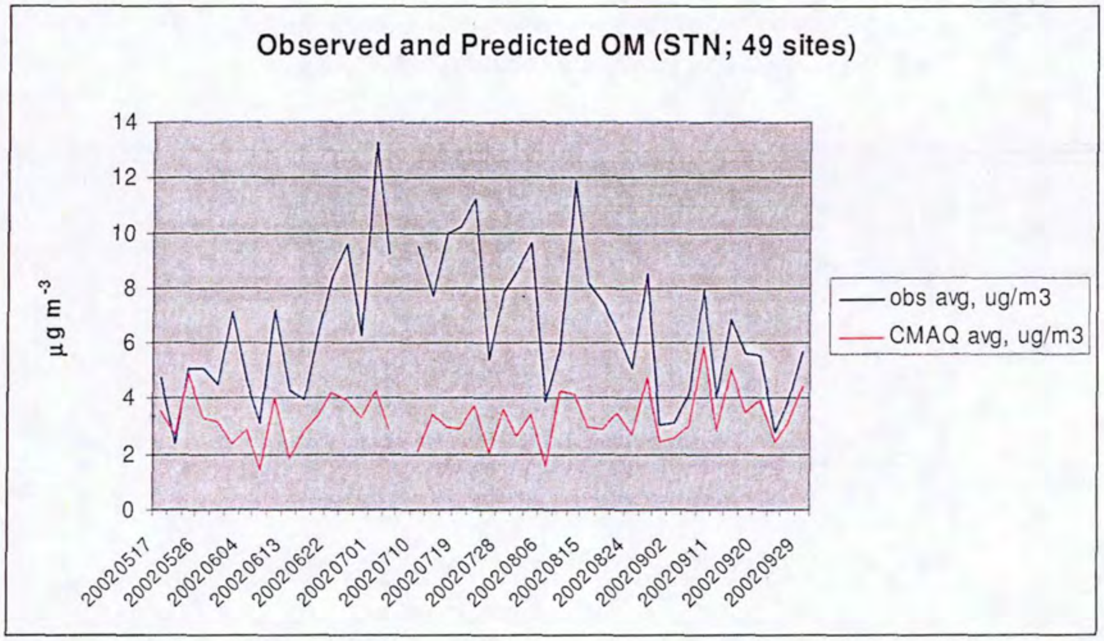

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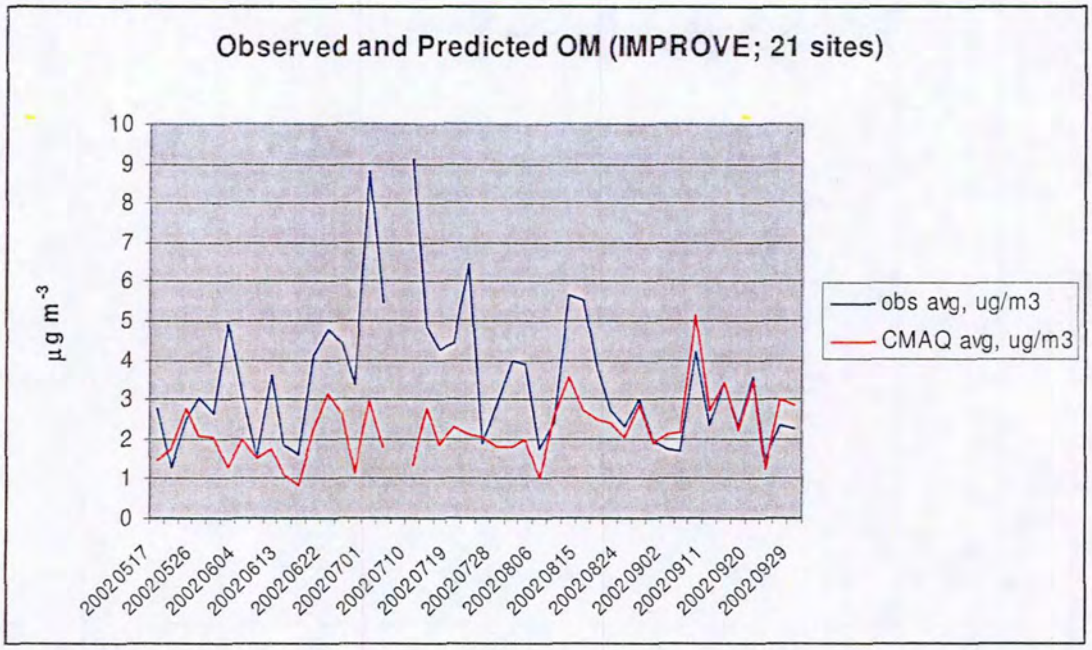

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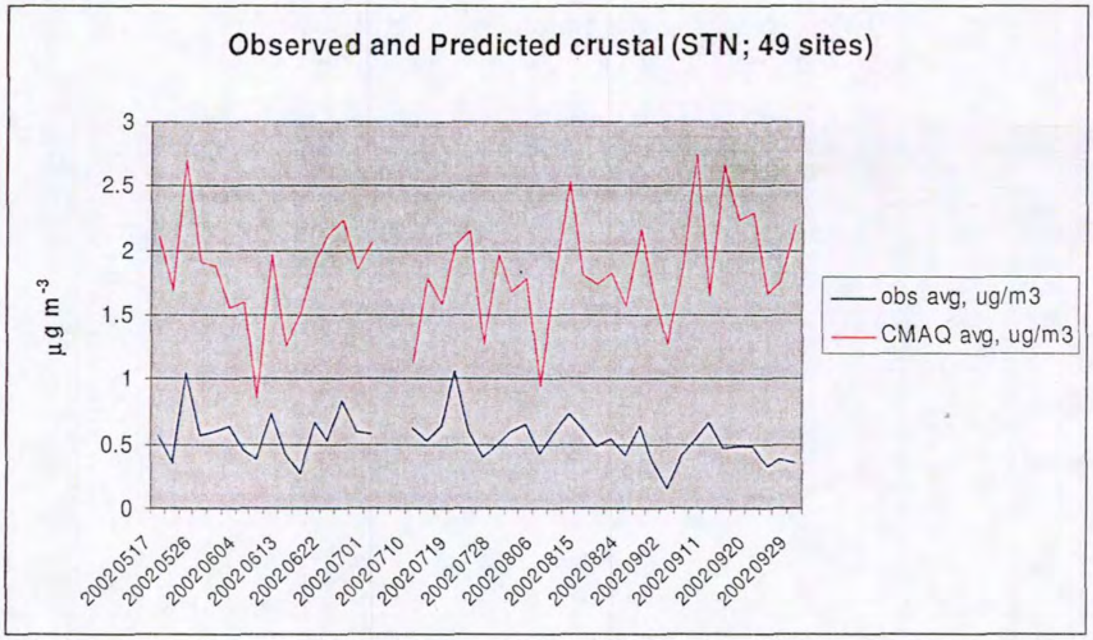

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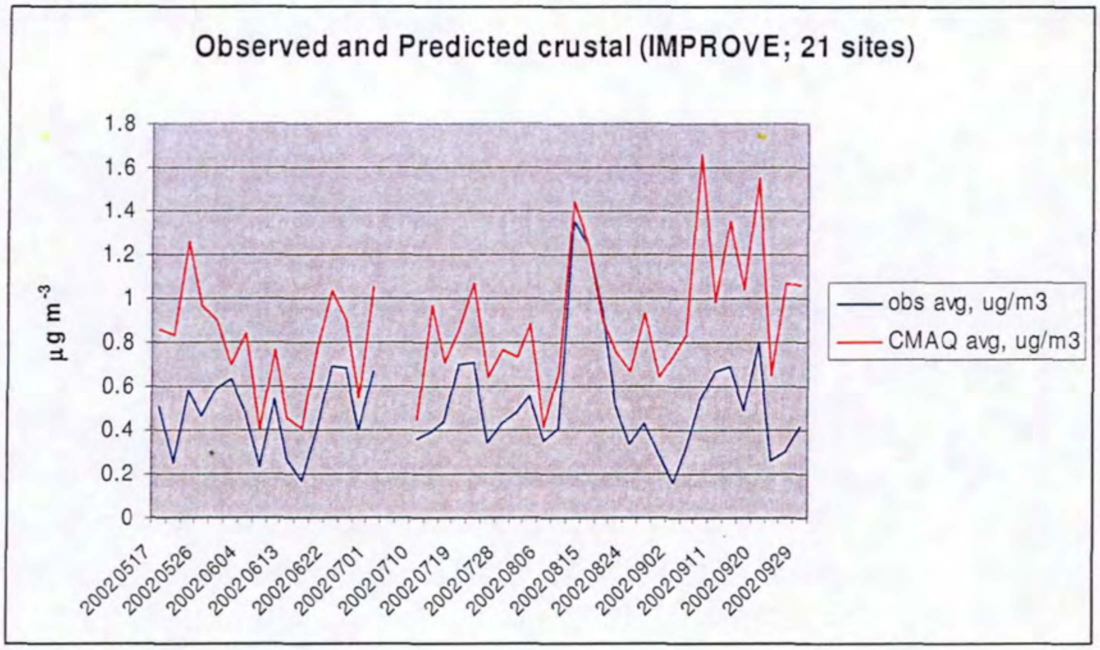

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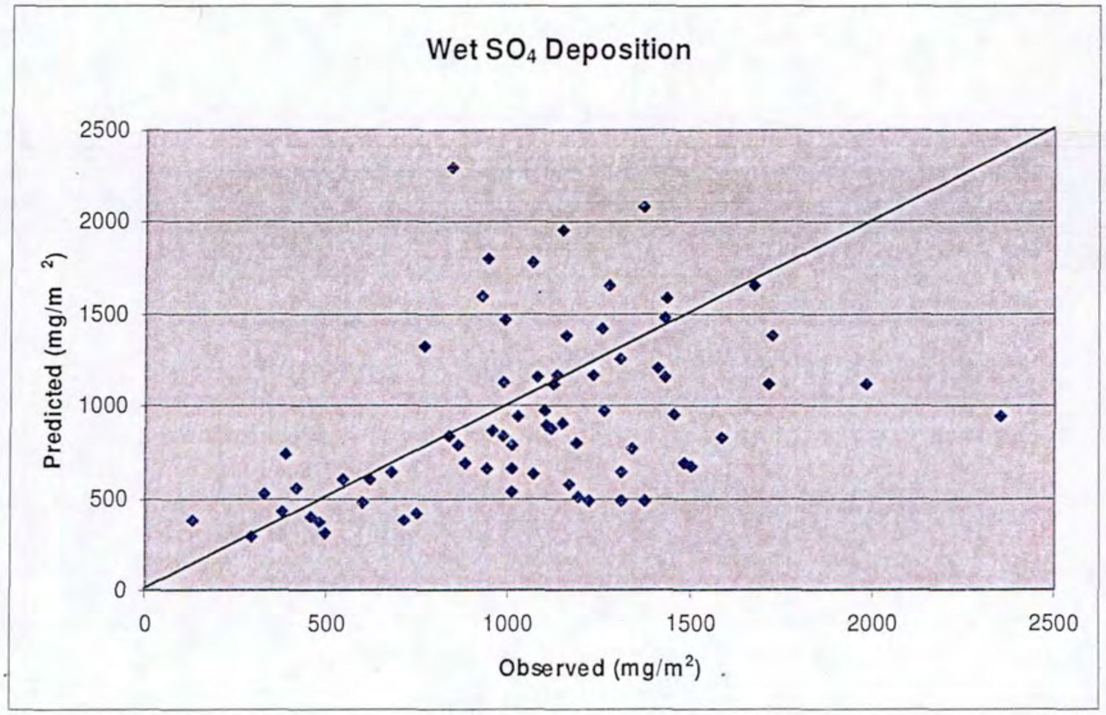

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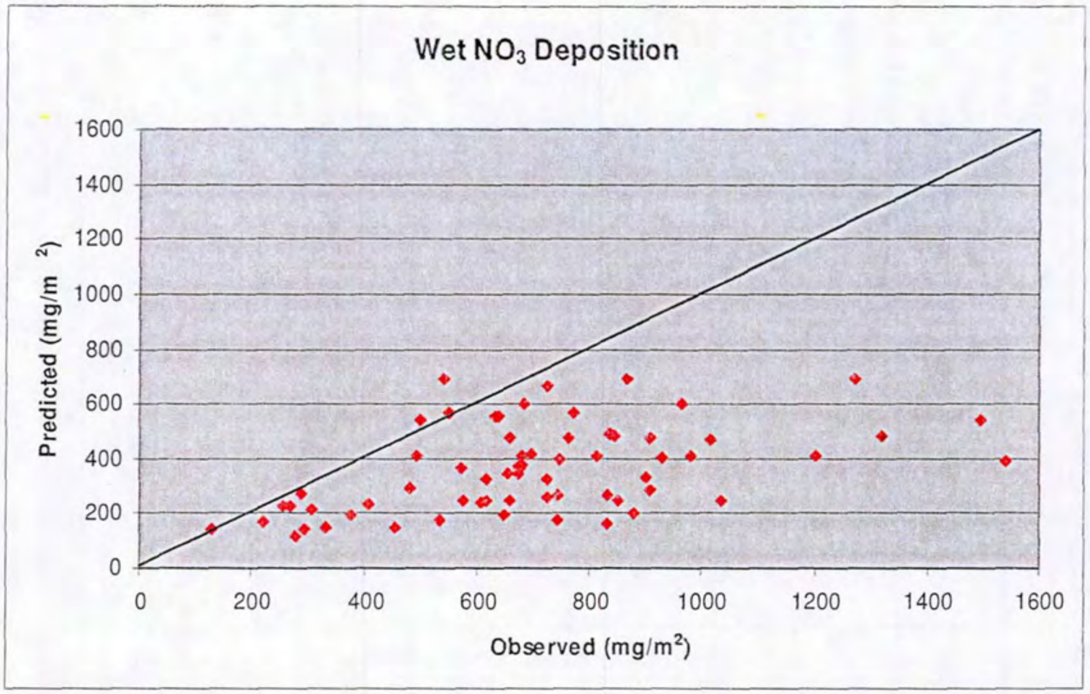

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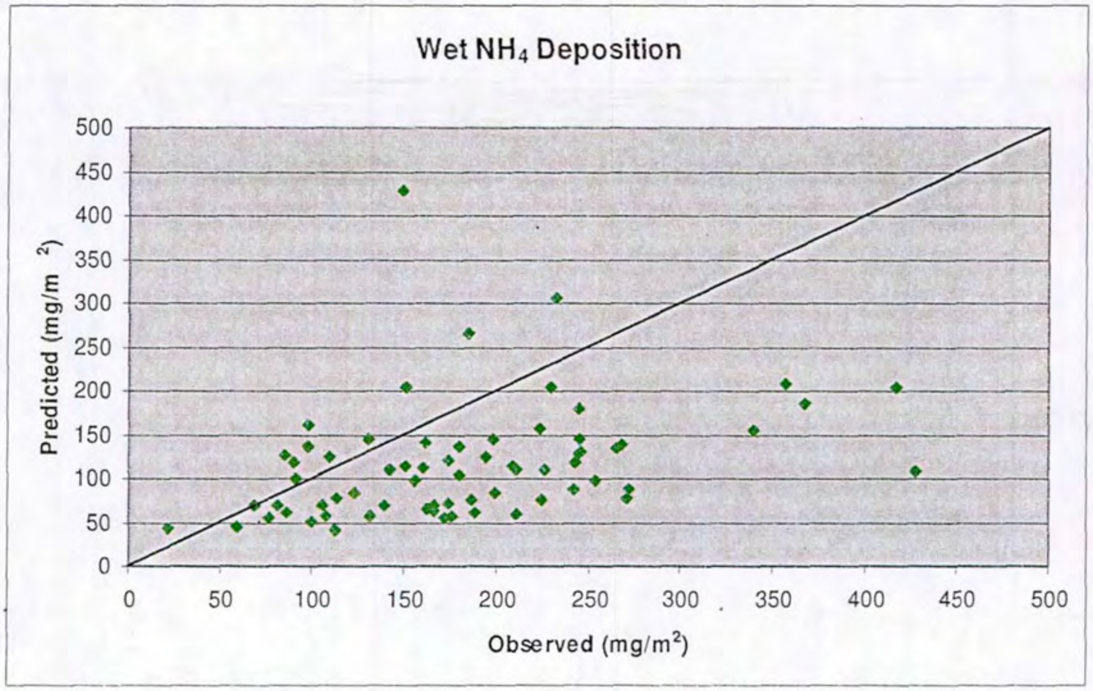

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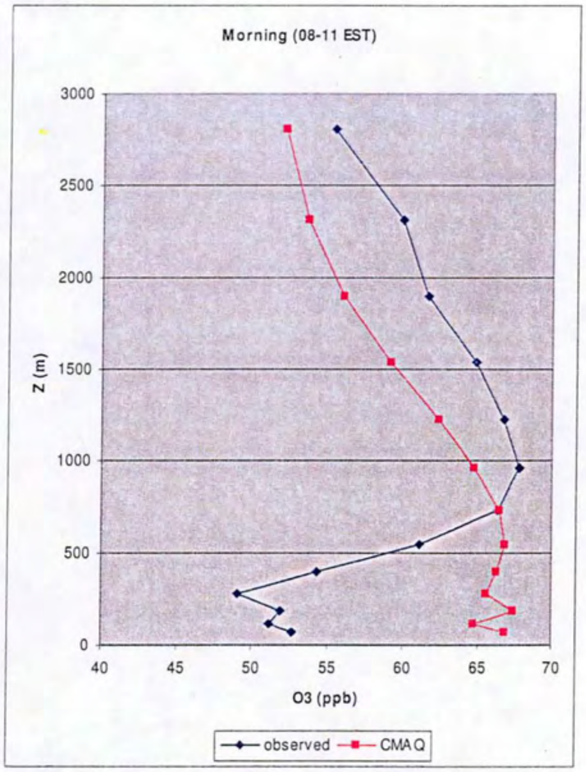

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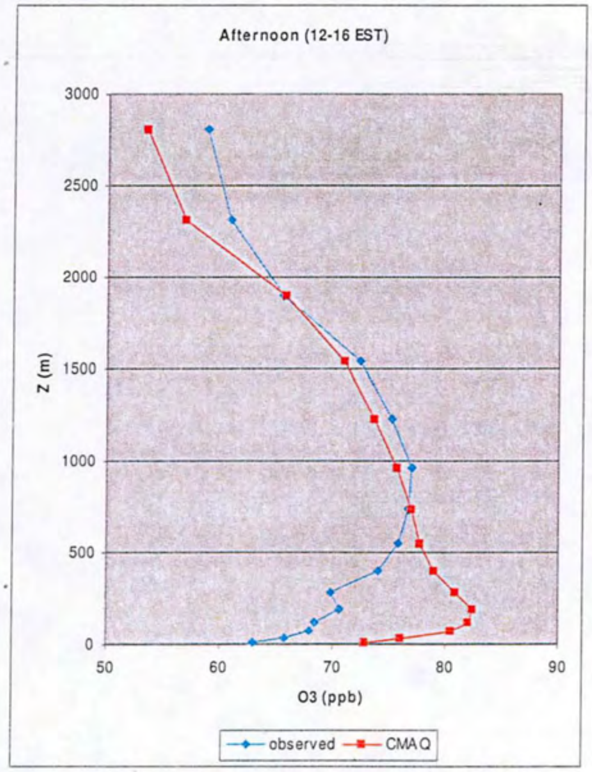

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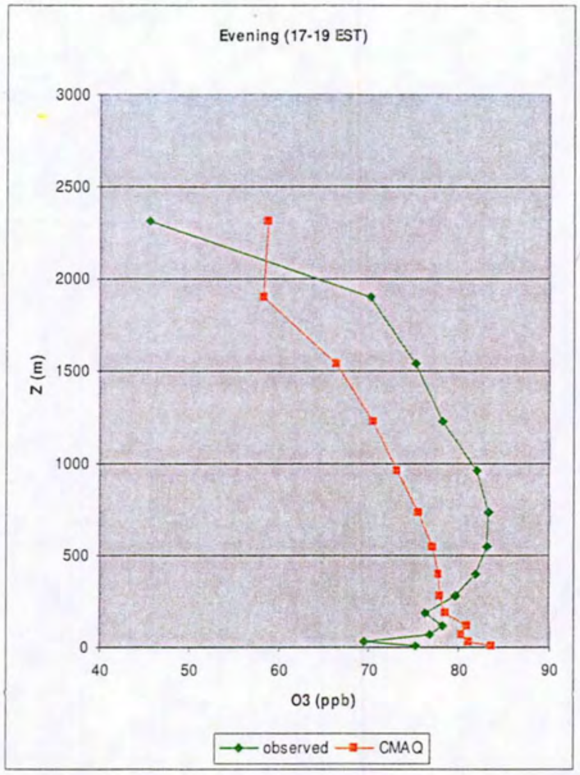

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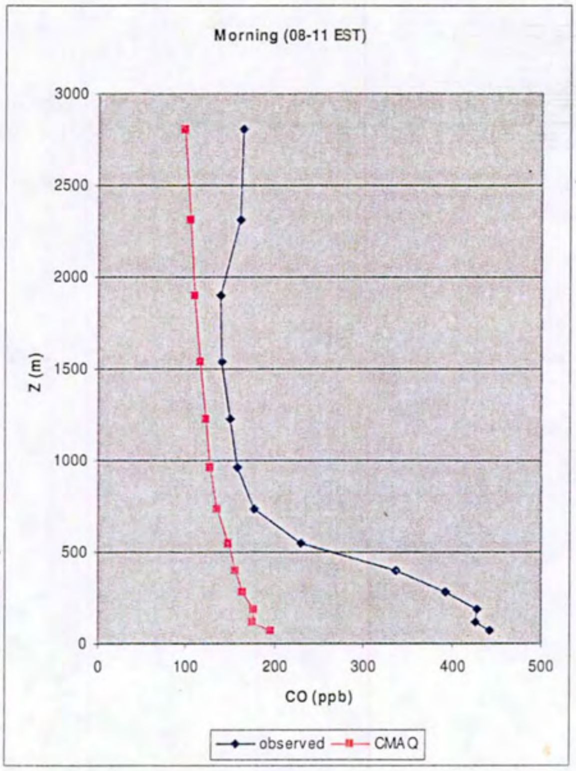

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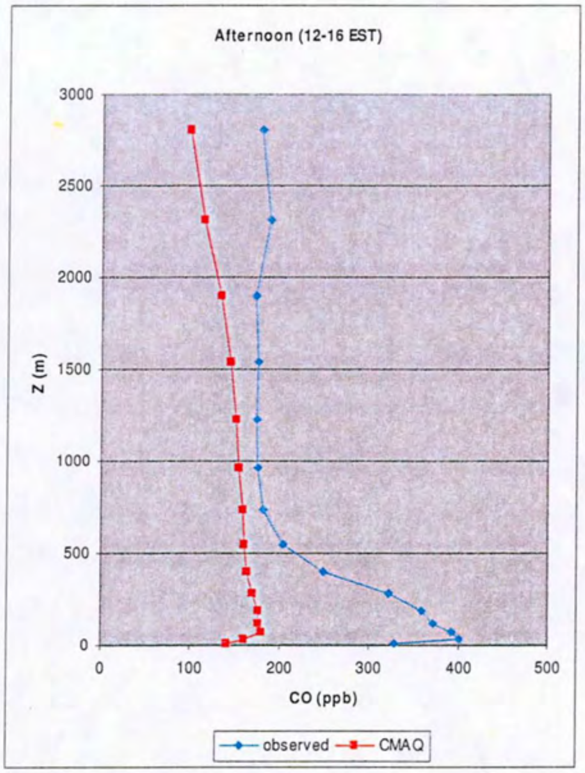

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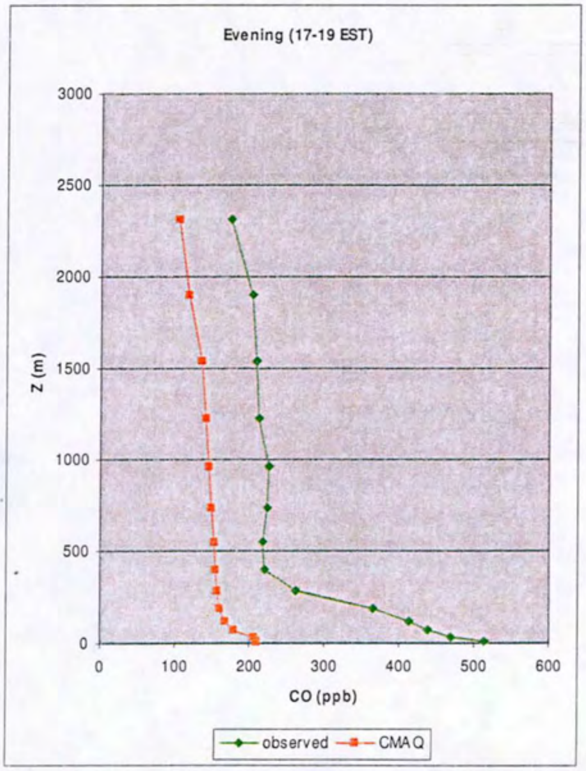

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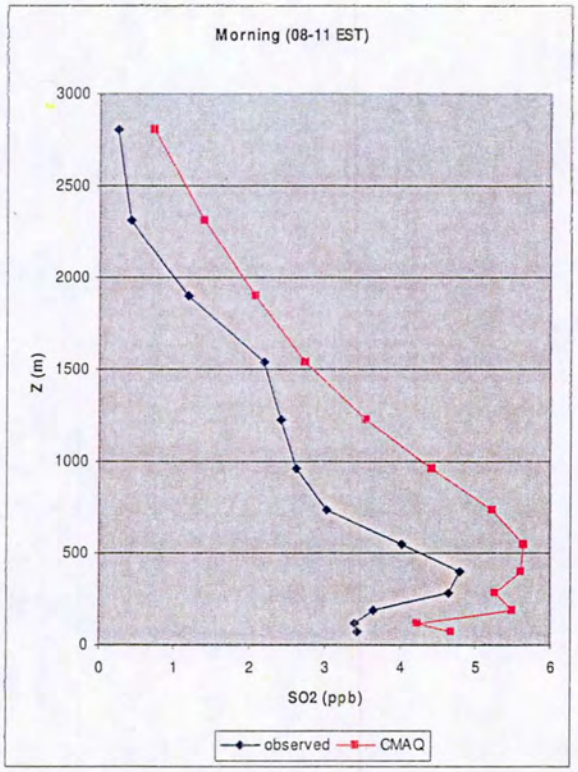

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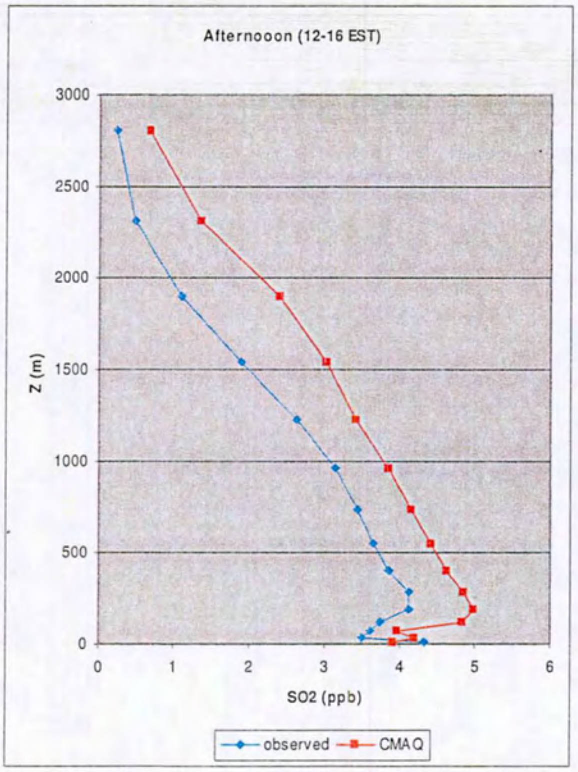

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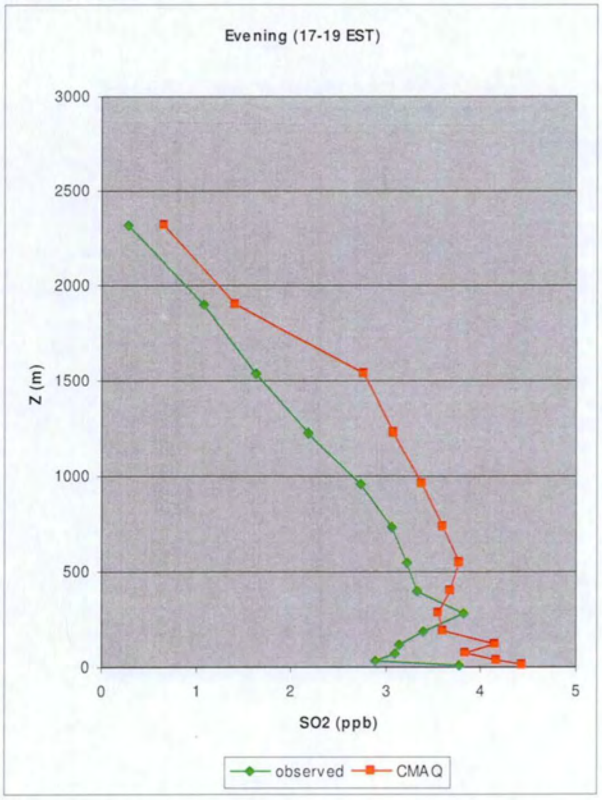


Evening (17-19 EST)
3000
2500
2000
1500
1000
500
0
Z (m)
0
1
2
3
4
5
SO2 (ppb)
observed
CMAQ

ATTACHMENT T

NYSDEC Technical Support Document TSD-1d

TSD-1d

8hr Ozone Modeling using the SMOKE/CMAQ system

Bureau of Air Quality Analysis and Research
Division of Air Resources
New York State Department of Environmental Conservation
Albany, NY 12233

February 1, 2006

Air Quality Modeling Domain

The modeling domain utilized in this application represented a sub-set of the inter-RPO's continental modeling domain that covered the entire 48-state region with emphasis on the Ozone Transport Region. The OTC modeling domain at 12km horizontal mesh is displayed in Figure 1 is part of the 36km continental domain that is designed to provide boundary conditions (BCs). The particulars of the two modeling domains are:

The 36km domain covered the continental US by a 149 by 129 mesh in the east-west and north-south directions, respectively. The domain is based on Lambert Conformal Projection with the center at (97°W 40°N) and parallels at 33°N and 45°N. As evident from Figure 1, the 12km domain utilized in this analysis covers most areas of the eastern US and has 172 by 172 mesh in the horizontal. Both domains utilize 22 layers in the vertical extending to about 16km with 16 layers placed within the lower 3km.

Photochemical Modeling -- CMAQ

The CMAQ (version 4.5.1) with CB4 chemistry, aerosol module for $PM_{2.5}$ and RADM cloud scheme was utilized in this study. Photochemical modeling was performed with the CCTM software that is part of the CMAQ modeling package. Version 4.5.1 of this modeling software was obtained from the CMAS modeling center at http://www.cmascenter.org. The following module options were used in compiling the CCTM executable:

- Horizontal advection: yamo
- Vertical advection: yamo
- Horizontal diffusion: multiscale
- Vertical diffusion: eddy
- Plume-in-Grid: non operational
- Gas phase chemical mechanism: CB-4
- Chemical solver: EBI
- Aerosol module: aero3
- Process analysis: non operational

The following computational choices were made during compilation:

- Compiler version: PGI 6.0
- Fortran compiler flags:-Mfixed -Mextend -Bstatic -O2 -module ${MODLOC} -I.
- C compiler flags: -v -O2 -I${MPICH}/include
- IOAPI library: version 3.0
- NETCDF library: version 3.6.0
- Parallel processing library version: mpich 1.2.6
- Static compilation on 32-bit system

The following choices were made for running the executable:

- Number of processors: 8
- Domain decomposition for parallel processing: 4 columns, 2 rows
- Number of species written to the layer-1 hourly-average concentration output (ACONC) file: 39 (O3, NO, CO, NO2, HNO3, N2O5, HONO, PNA, PAN, NTR, NH3, SO2, FORM, ALD2, PAR, OLE, ETH, TOL, XYL, ISOP, ASO4I, ASO4J, ANO3I, ANO3J, ANH4I, ANH4J, AORGAI, AORGAJ, AORGPAI, AORGPAJ, AORGBI, AORGBJ, AECI, AECJ, A25I, A25J, ACORS, ASEAS, ASOIL)
- Each daily simulation was performed for 24 hours starting at 05:00 GMT (00:00 EST)

The following postprocessing steps were performed using utility tools from the "ioapi" software package obtained from http://www.baronams.com/products/ioapi/AA.html#tools:

- Extract and combine the following species for each hour for the first 16 model layers from the full 3-D instantaneous concentration output file: O3, CO, NO, NO2, NOY_1 (*=NO + NO2 + PAN + HNO3*), NOY_2 (*=NO + NO2 + PAN + HNO3 + HONO + N2O5 + NO3 + PNA + NTR*), HOX (*=OH + HO2*), VOC (*=2*ALD2 + 2*ETH + FORM + 5*ISOP + 2*OLE + PAR + 7*TOL + 8*XYL*), ISOP, PM2.5 (*=ASO4I + ASO4J + ANO3I + ANO3J + ANH4I + ANH4J + AORGAI + AORGAJ + 1.167*AORGPAI + 1.167*AORGPAJ + AORGBI + AORGBJ + AECI + AECJ + A25I + A25J*), PM_SULF (*=ASO4I + ASO4J*), PM_NITR (*=ANO3I + ANO3J*), PM_AMM (*=ANH4I + ANH4J*), PM_ORG_SA (*=AORGAI + AORGAJ*), PM_ORG_PA (*=1.167*AORGPAI + 1.167*AORGPAJ*), PM_ORG_SB(*=AORGBI + AORGBJ*), PM_ORG_TOT (*=AORGAI + AORGAJ + 1.167*AORGPAI + 1.167*AORGPAJ + AORGBI + AORGBJ*), PM_EC (*=AECI + AECJ*), PM_OTH (*=A25I + A25J*), PM_COARS (*=ACORS + ASEAS + ASOIL*), SO2, HNO3, NH3, H2O2
- Extract all species for all model layers for the last hour of each daily instantaneous concentration output file to enable "hot" restarts of modeling simulations
- Create daily files of hourly running-average 8-hr ozone concentrations with time stamps assigned to the first hour of the averaging interval

The following files are archived on LTO2 computer tapes (each tape holds approximately 200 Gb of data) for each day:

- Aerosol/visibility file
- Layer-1 hourly-average concentration output file (contains 39 species)
- Dry deposition file
- Wet deposition file
- Extracted 16-layer species file
- Restart file (last hour of full 3-D instantaneous concentration file)
- Hourly 8-hr concentration file

Photolysis Rates

One of the inputs to CMAQ is the photolysis rates. In this study, photolysis rate lookup tables were generated for each day of 2002 with the JPROC software that is part of the CMAQ modeling package. This software was obtained from the CMAS modeling center at http://www.cmascenter.org. Rather than using climatological ozone column data, daily ozone column measurements from the NASA Earthprobe TOMS instrument were downloaded from ftp://toms.gsfc.nasa.gov/pub/eptoms/data/ozone/Y2002/ and used as input to the JPROC processor. It should be noted that TOMS data were missing for the time period from August 3 – 11, 2002. The missing period was filled as follows-- TOMS data file for August 2 was used as JPROC input for August 3rd through August 7th, and the TOMS data file for August 12th was used as JPROC input for August 8th through August 11th.

Boundary Conditions (BCs)

The boundary conditions for the 12km grid were extracted from the 36km CMAQ simulation. The 36km simulation utilized boundary conditions that were based on a one-way nest approach to GEOS-CHEM global model outputs (Moon and Byun 2004, Baker 2005). As stated above, the intent of the 36km CMAQ simulation was to provide the BCs for the 12km model that would be more reflective of the emissions and meteorology rather than to use either clean or arbitrary pollutant fields. Also, in this study the CMAQ simulations utilized a 15-day ramp-up period, thereby minimizing the propagation of the boundary fields into the areas of concern. A report on the setup and application of the 36km CMAQ and the extraction of the BCs is available from NYSDEC.

Meteorological data

The meteorological data for this study was based on MM5 modeling (see Meteorological Modeling, 2007). The MM5 fields are then processed by MCIP version 3.0, a utility available as part of the CCTM software from CMAS Modeling Center (see http://www.cmascenter.org) to provide CMAQ model-ready inputs.

Emissions

The emissions data for 2002 were generated by individual states within the OTR and were assembled and processed through the Mid Atlantic Northeast Visibility Union (MANE-VU), a Regional Planning Organization (RPO). These emissions were then processed by NYSDEC using SMOKE processor to provide CMAQ compatible inputs (Anthro-Emissions 2006). The 2002 emissions for the non-OTR areas within the modeling domain were obtained from the corresponding RPOs and were processed using SMOKE, in a manner similar to that of the OTR.emissions. Details of this processing are outlined in the report (Pechan 2007), and the hourly biogenic emissions (Bio-Emissions, 2006)

CMAQ simulations

CMAQ simulations were performed using the one-way nesting approach in which we perform the continental CMAQ simulation at 36km grid spacing. For this simulation we utilized clean initial conditions with boundary conditions extracted from the simulation of GEOS-CHEM global chemical model. The interface program used in this application was developed by University of Huston (Moon and Byun 2004), which was applied to obtain hourly 36km boundary concentrations from GEOS-CHEM outputs. The CMAQ 36km simulation was initiated from December 15, 2001 with the first 15 days as spin up period and terminated on December 31, 2002. The simulation utilized the 2002 emissions data available from the RPOs and 2002 MM5 meteorological fields developed by the University of Maryland (TSD-1a). The hourly boundary fields for the 12km CMAQ domain were obtained by application of BCON program to the 3-D concentration fields generated by the 36km CMAQ simulation.

The 12km simulations for both base and future year were assigned the boundary conditions based on the 36km CMAQ simulation and clean initial conditions. The simulation period covered was from April 15 through September 30, with the first 15 days of April set as ramp-up or spin-up period and that only data from May 1 through September 30 were used in the analysis. Details on CMAQ setup and run scripts are available from NYSDEC.

References

Baker, K.: (2005) http://www.ladco.org/tech/photo/present/ozone.pdf

Moon, N. and D. Byun: (2004) A simple user's guide for "geos2cmaq"code: Linking CMAQ with GEOS-CHEM. Version 1.0. Institute for Multidimensional Air quality Studies (IMAQS), University of Houston, Houston TX.

Meteorological Modeling: (2007) Meteorological Modeling using Penn State/NCAR 5th Generation Mesoscale Model (MM5). TSD-1a

Pechan: (2006) Technical Support document for 2002 MANE-VU SIP Modeling inventories, version 3. Prepared by E. H. Pechan & Associates, Inc. 3622 Lyckan Parkway, Suite 2005, Durham, NC 27707.

Bio-Emissions: (2006) Processing of Biogenic Emissions for OTC/MANE-VU Modeling. TSD-1b

Anthro-Emissions: (2006) Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations. TSD-1c

ATTACHMENT U

CALGRID Modeling Protocol

Modeling Protocol for the OTC CALGRID Screening-Level Modeling Platform for the Evaluation of Ozone, Fine Particulate Matter, and Regional Haze

December 29, 2009

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
Concord, NH 03302

1.0 Introduction

The Ozone Transport Commission (OTC) has sponsored the development of a photochemical modeling system to assist states in the preparation of their State Implementation Plans (SIPs) for attaining the eight-hour National Ambient Air Quality Standard (NAAQS) for ozone. The Community Multiscale Air Quality Model (CMAQ) is the basis of the OTC SIP-quality modeling platform that is being used in states' eight-hour ozone attainment SIPs. CMAQ was also an important analysis tool in states' SIPs for regional haze. It was used to assess source contributions to regional haze and to evaluate the effectiveness of control strategies for the mitigation of future visibility impairment.

Running the CMAQ modeling platform is very resource intensive and usually requires the use of a Unix-based operating system. Therefore, the CMAQ modeling that is being done in support of the eight-hour ozone and regional haze SIPs is limited to a handful of modeling centers that have the necessary expertise and computer resources. Similarly, because of the substantial effort, time, and storage space required to run the SIP-quality CMAQ platform, it is impractical to assess a large number of run scenarios.

Consequently, OTC sponsored the development of an additional grid-based photochemical modeling platform that states could use as a screening tool for running additional emissions control strategies or performing sensitivity runs. The requirements for this additional modeling platform were that it be flexible, portable, and easily accessible to agencies that wish to use it. In this manner, a larger number of run scenarios could be modeled, allowing states to screen a wider variety of potential control strategies.

The California Grid Model (CALGRID) was selected as the basis of this screening platform. CALGRID is a grid-based photochemical modeling platform that is designed to be run in a Windows environment. CALGRID has recently undergone a series of improvements and enhancements, with the most recent version being designated CALGRID Version 2.45. CALGRID Version 2.45 is being used as the screening platform for the OTC eight-hour ozone attainment SIPs. CALGRID is also being used in screening-level analyses for fine particulate matter (particulate matter with an equivalent aerodynamic diameter of 2.5 microns or less, also known as PM2.5) and regional haze. This document outlines the manner in which CALGRID will be used in these efforts.

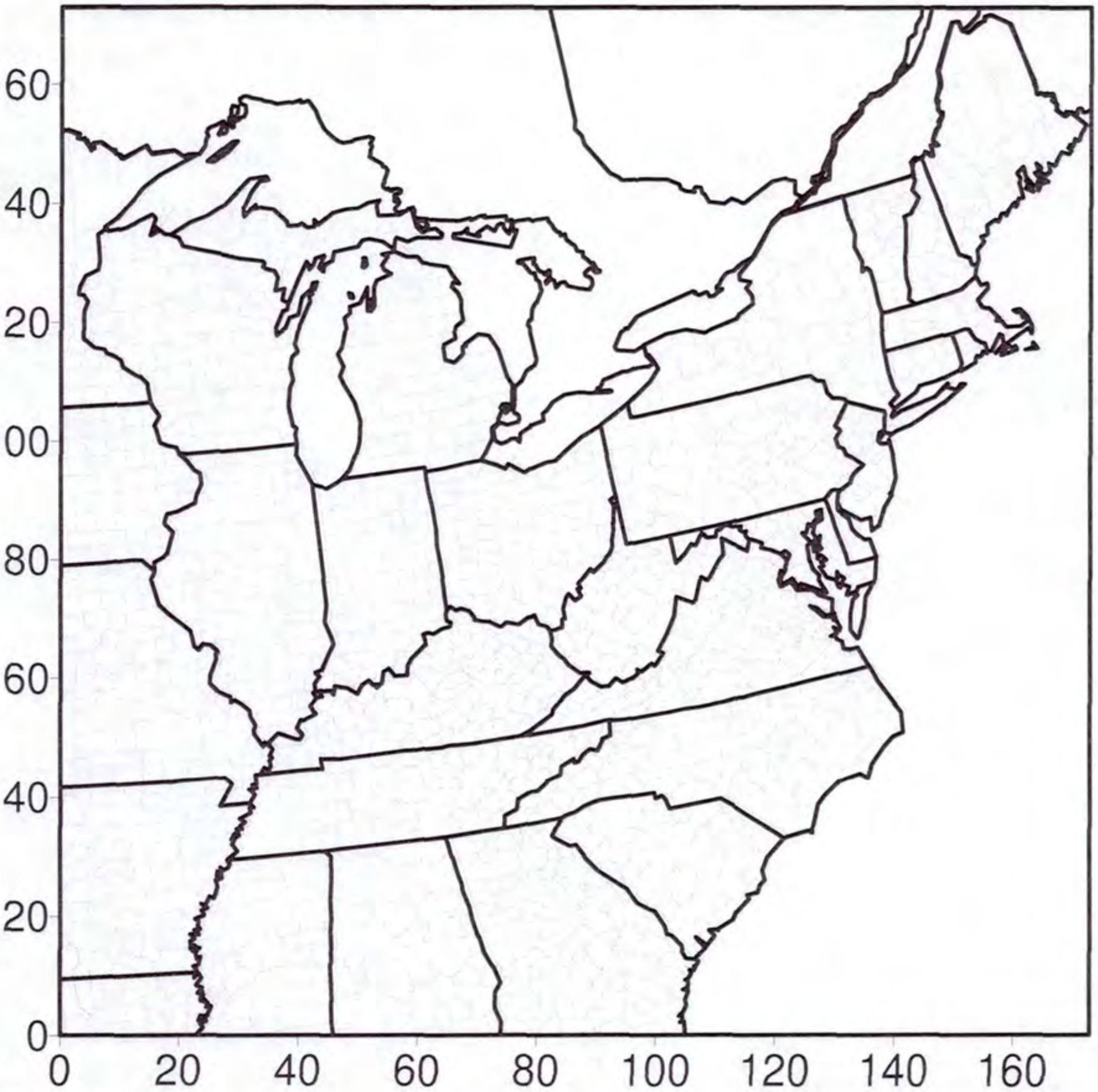
2.0 Platform Description and Model Inputs

To make the CALGRID modeling platform the best possible tool to supplement the SIP-quality CMAQ platform, it was decided that CALGRID would be run on the same modeling domain using a common set of model inputs. All boundary conditions, meteorology, and emissions inputs were the same as those used for the SIP-quality CMAQ platform. Processing programs were written to convert these inputs into a format useable by the CALGRID model. The modeling domain and model inputs are described in the sections below.

2.1 Modeling Domain

The OTC CMAQ/CALGRID modeling domain was set up on a Lambert Conic Conformal projection and covers the eastern United States and parts of Canada. The southwest corner of the domain was set at 264 km, -888 km and the northeast corner was set to 2328 km, 1176 km. A 12-km grid cell resolution was used with 172 grid cells in the east-west direction and 172 grid cells in the north-south direction. For the vertical grid definition, 22 layers were used in the CMAQ simulations. For CALGRID, the processing programs that were used to reformat the boundary conditions, meteorology, and emissions mapped the 22 layers used for CMAQ to a total of nine vertical layers for the CALGRID modeling. The OTC CMAQ/CALGRID modeling domain is shown in Figure 1.

Figure 1: Map of the OTC CMAQ/CALGRID Modeling Domain



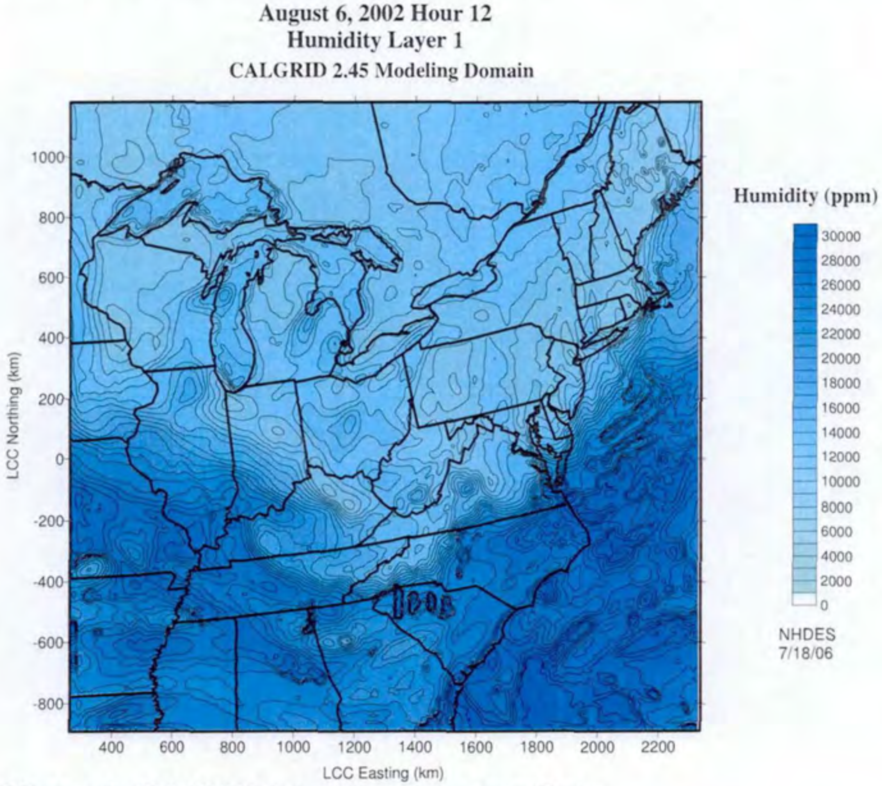
2.2 Boundary Conditions

For the OTC CMAQ modeling, boundary conditions were derived from GEOS-Chem (Goddard Earth Observing System) global atmospheric simulations by running CMAQ on the 36-km continental grid. For the CALGRID platform, initial conditions, side boundary conditions, and top layer concentrations were derived from the CMAQ boundary conditions files by means of a processing program. This program mapped the 22 vertical layers used in the CMAQ simulations to the nine layers used with CALGRID. It produced the necessary side boundary file and top layer concentration file for each modeled episode day. It also produced an initial conditions file for each episode day processed; these files could be retained so that the user could begin a CALGRID simulation on any desired episode day.

2.3 Meteorology

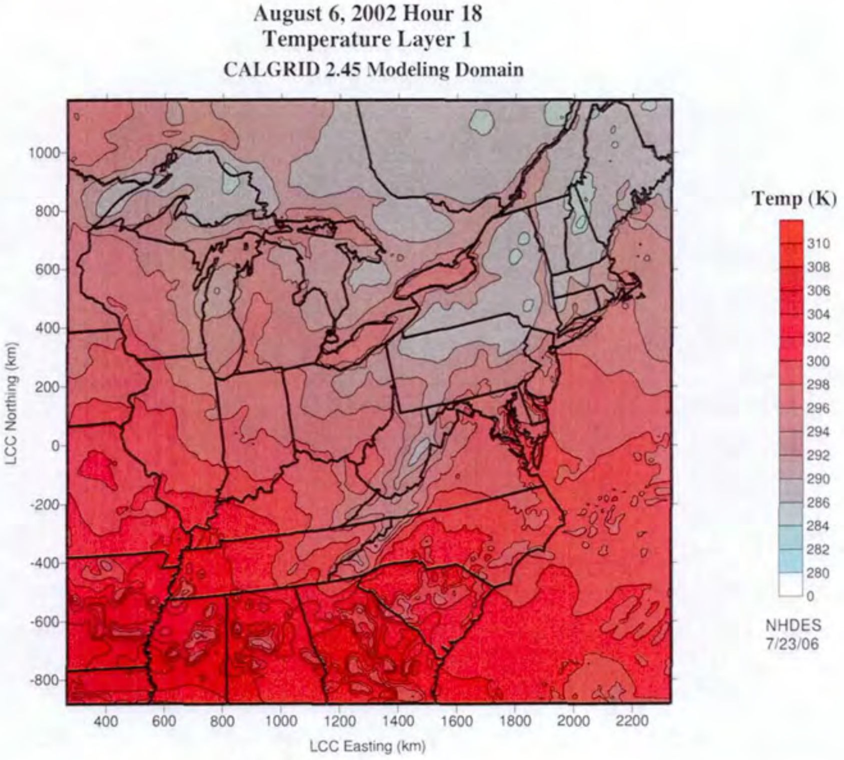
The meteorological modeling that was done in support of the OTC CMAQ SIP-quality modeling platform was performed by the University of Maryland (UMD) in conjunction with staff at the New York State Department of Environmental Conservation (NYSDEC). UMD used the Penn State/National Center for Atmospheric Research 5th Generation Mesoscale Model (MM5) Version 3.6 to generate year 2002 meteorological inputs. The details of this work are described in NYSDEC's Technical Support Document TSD-1a, *Meteorological Modeling Using Penn State/NCAR 5th Generation Mesoscale Model (MM5), February 1, 2006.* For the CALGRID modeling platform, a processing program was used to interpolate the MM5 outputs to the CALGRID modeling grid and map them to CALGRID's vertical layer structure. QA/QC plots were generated during the processing to ensure the accuracy of the interpolated data. Figures 2 through 4 show example QA/QC plots from the re-formatting of the meteorological data.

Figure 2: QA/QC Plot of Humidity Data



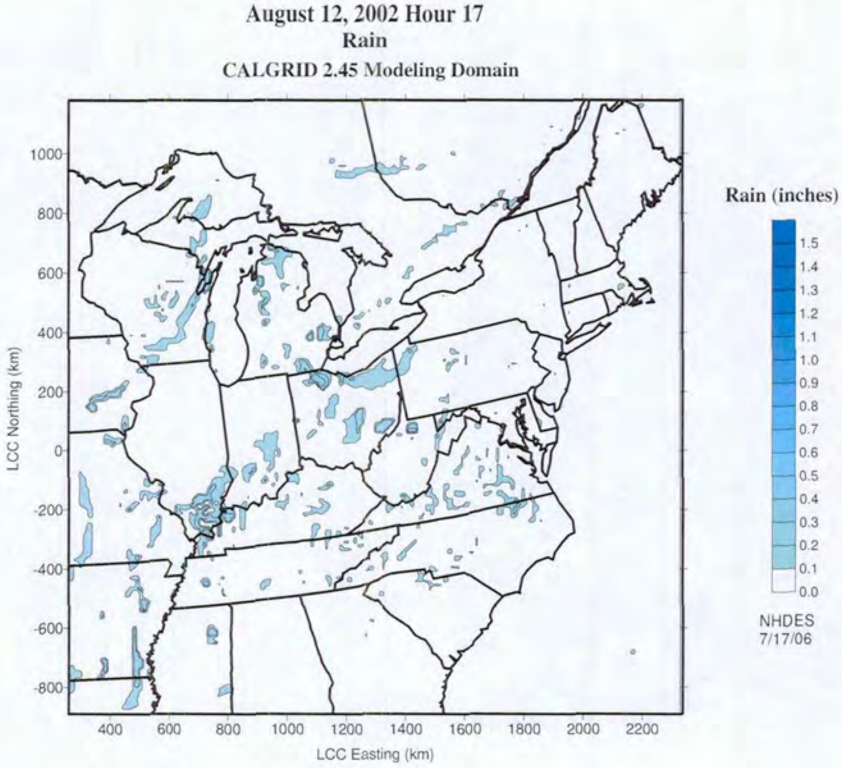
August 6, 2002 Hour 12
Humidity Layer 1
CALGRID 2.45 Modeling Domain

Figure 3: QA/QC Plot of Temperature Data



August 6, 2002 Hour 18
Temperature Layer 1
CALGRID 2.45 Modeling Domain

Figure 4: QA/QC Plot of Rainfall Data



2.4 Emissions

The Regional Planning Organizations (RPOs) and their contractors were responsible for preparing modeling emissions inventories for use in the OTC CMAQ SIP-quality modeling. The RPOs prepared a set of accurate, up-to-date, and quality assured emissions inventories for the 2002 Base Case and three future years, 2009, 2012, and 2018. For the future years, emissions inventories were prepared for two emissions control scenarios: one reflecting those emissions controls that are in place or likely to be in place by 2009, and another that reflects additional control strategies that may be needed to demonstrate attainment with the eight-hour ozone standard. The first scenario is referred to as “On The Books/On The Way” (OTB/OTW), and the second is referred to as “Beyond On The Way” (BOTW). A third scenario, sometimes referred to as "Best & Final", was developed to assess additional potentially reasonable control programs aimed at improving visibility. All of these inventories were broken down into the following general emissions source categories: biogenic, point, area, non-road mobile, and on-road mobile.

Using these inventories, NYSDEC and the other modeling centers, the Virginia Department of Environmental Quality (VADEQ) and Northeast States for Coordinated Air Use Management (NESCAUM), generated the necessary emissions inputs for CMAQ using the Sparse Matrix Operator Kernel Emissions (SMOKE) model. For the CALGRID modeling effort, the pre-merged SMOKE emissions files were obtained from the modeling centers and re-formatted for input into EMSPROC, the emissions pre-processor for the CALGRID modeling system. The pre-merged SMOKE files that were obtained from the modeling centers were broken down into the biogenic, point, area, non-road, and on-road categories mentioned earlier. These files by component were then converted for use with EMSPROC, thus giving users of the CALGRID modeling system the flexibility to analyze a wide variety of emissions control strategies. QA/QC plots were generated during the re-formatting of the emissions data to ensure that an accurate modeling inventory was generated for the CALGRID platform. Example emissions QA/QC plots are shown in Figures 5 through 8.

Figure 5: QA/QC Plot of Surface Source CO Emissions

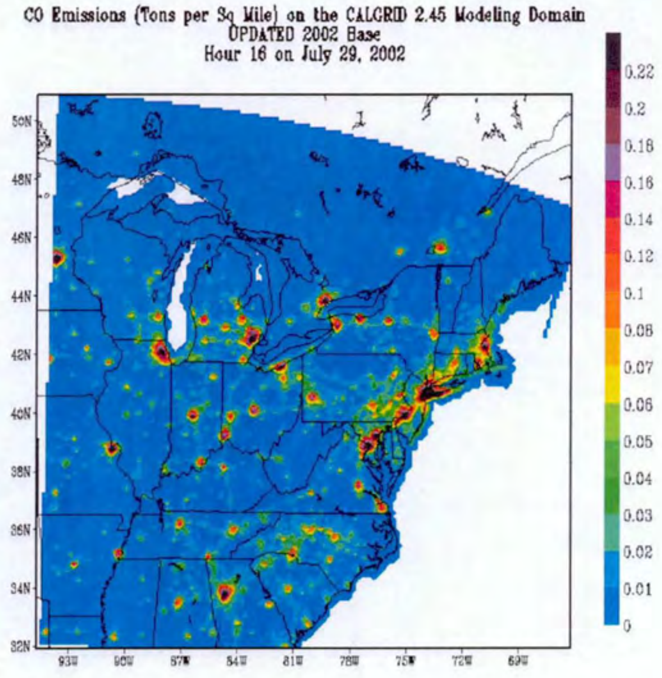


Figure 6: QA/QC Plot of Surface Source VOC Emissions

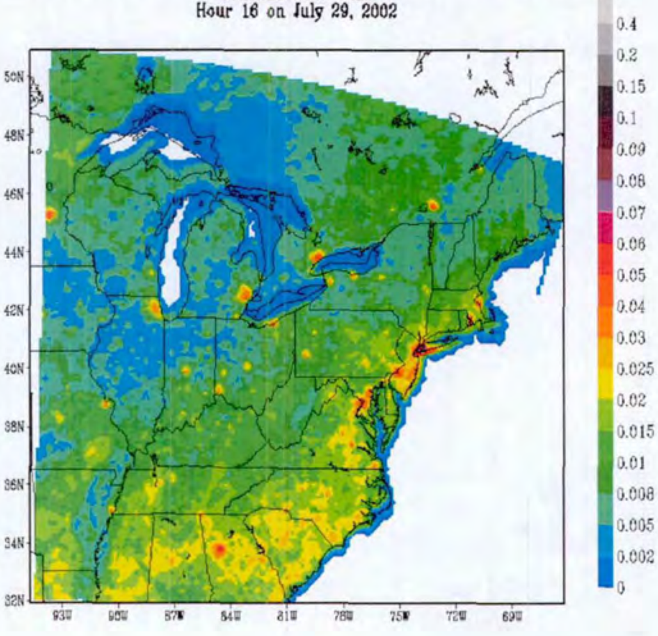


Figure 7: QA/QC Plot of Point Source NOx Emissions

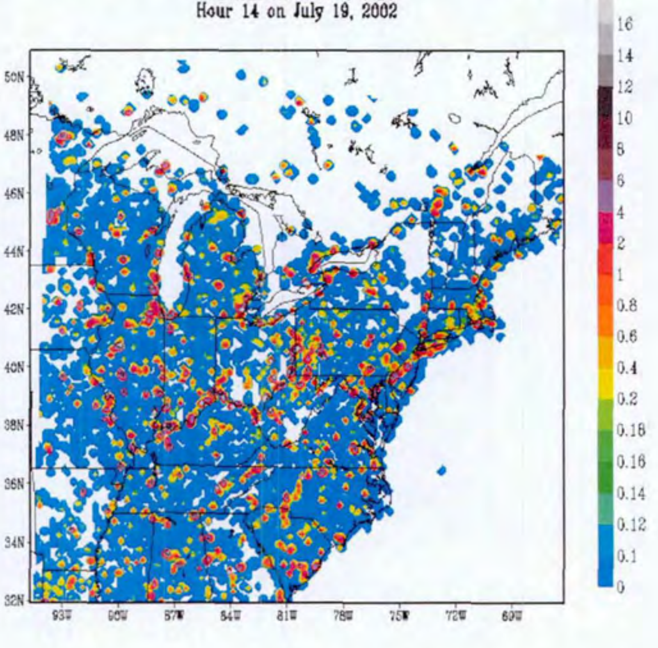
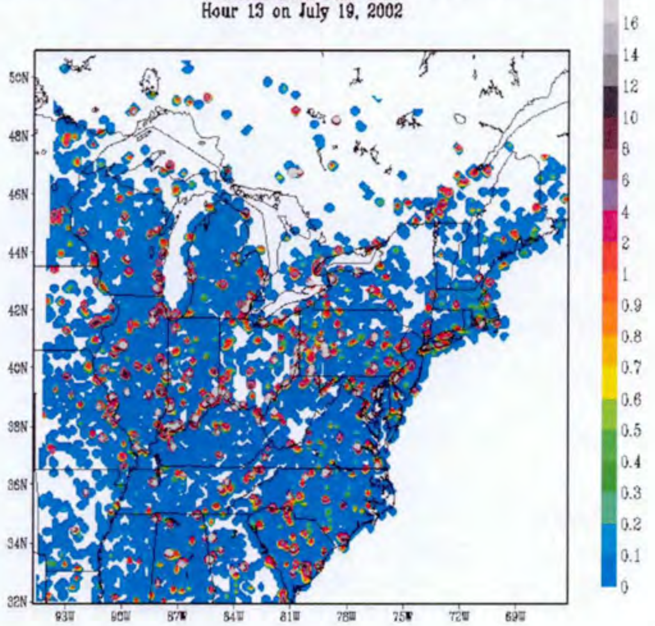


Figure 8: QA/QC Plot of Point Source SO2 Emissions



3.0 CALGRID Model Outputs

A variety of post-processing programs have been developed to assist users of the CALGRID modeling platform in visualizing and tabulating model results. These post-processors are designed to take the hourly concentration output generated by the CALGRID model and produce statistical results for desired averaging periods and geographic areas. CALGRID can also generate output suitable for plotting with standard graphical packages such as the Center for Ocean-Land-Atmosphere Studies' Grid Analysis and Display System (GrADS) or Golden Software's SURFER.

As with the CMAQ SIP-quality modeling platform, it was decided that the CALGRID screening results should be used in a relative manner. Ratios of model-predicted base case and future scenario concentrations would be applied to current monitored ozone design values to generate estimated future design values (DVFs) for the future-year scenario of interest. It is these DVFs that are used in the determination of attainment.

4.0 Episode Selection

For the CMAQ SIP-quality ozone modeling analysis, the five-month ozone season of 2002 was selected for modeling because it met EPA's episode selection criteria of containing episode days that are meteorologically representative of typical high ozone exceedance days and that are severe enough that any control strategy that is predicted to reach attainment on those days would reach attainment on other less severe days.

Similarly, the CALGRID screening platform was run for the summer period from May 15 to September 15, 2002 for the 2002 Base Case and 2009 OTB/OTW and BOTW scenarios. However, running the full summer episode, even with the CALGRID screening platform, is very time-consuming and resource intensive. In order to increase production and maximize the number of scenarios that can be evaluated with the CALGRID screening platform, it was decided that shorter modeling episodes would be selected that adequately reproduced the results obtained by running the full summer episode. An extensive analysis was undertaken to run a number of shorter summer episodes and compare the resulting predicted DVFs with those obtained for the full summer episode. The 2002 Base Case and 2009 OTB/OTW scenarios were used in this evaluation. It was found that the combined DVFs calculated from the July 6 to July 23, 2002 and July 30 to August 16, 2002 modeling episodes best represented those from the full summer episode (note that July 6th and July 30th are considered to be model warm-up days).

5.0 CALGRID Model Performance Evaluation

A qualitative and quantitative assessment was made of the CALGRID screening platform's ability to reproduce observed ozone, PM2.5, and visibility. To assess its performance, the CALGRID screening platform was run for the 2002 Base Case for the July 30 to August 16, 2002 modeling episode. Predicted maximum eight-hour ozone concentrations at monitor locations were compared against observations for 2002. Comparisons were also made of predicted vs. observed PM2.5 and regional haze. All of these comparisons are described below and shown in the subsequent figures.

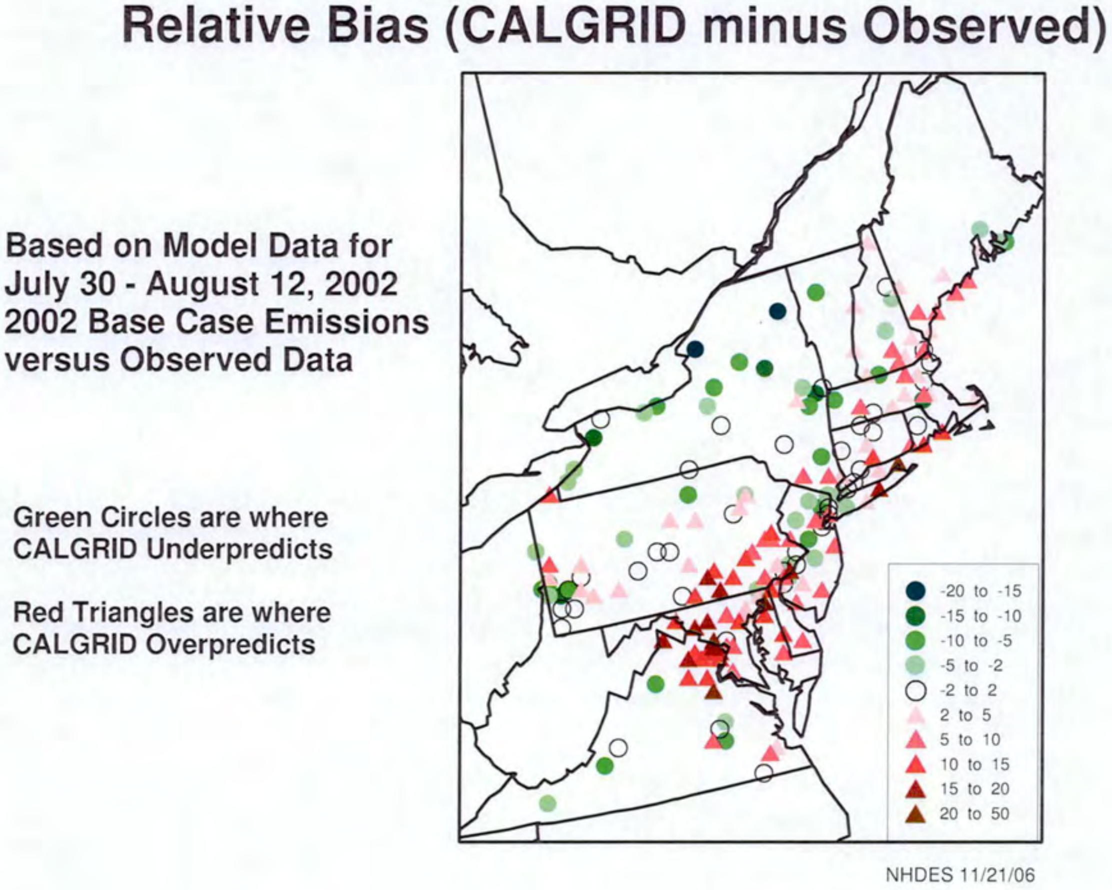
Figure 9 shows the relative bias between maximum eight-hour ozone observations and predicted CALGRID eight-hour ozone concentrations for the 2002 Base Case for the episode from July 30 through August 12. Figures 10 through 13 show plots of predicted 2002 Base Case ozone concentrations against 2002 observations for selected episode days. Although the CALGRID model has a tendency to over-predict, especially in the urban core areas of northern Virginia, Maryland, southeastern Pennsylvania, New York City and Boston, it does a reasonable job of reproducing the pattern of the 2002 maximum ozone observations.

Figures 14 through 19 present predicted maximum 24-hour PM2.5 concentrations (top of each figure) against observations (bottom of each figure) for selected episode days. Included for comparison are corresponding maximum PM2.5 concentrations predicted with the Regional Modeling System for Aerosols and Dispersion (REMSAD). Observations include measurements taken at monitors in the IMPROVE network (Interagency Monitoring of Protected Visual Environments). These figures show that CALGRID reasonably reproduces the pattern of maximum daily PM2.5 observations and provides a similar pattern of predictions as REMSAD, which is state-of-the-science model for predicting particulate matter and other pollutants.

Figure 20 compares predicted haze index (bottom of figure) with observations at IMPROVE sites (top of figure) for a relatively clear episode day (May 14th). Figure 21 compares predicted haze index with observations for a relatively hazy day (August 12th).

Lastly, Figures 22 through 28 show time-series plots of predicted vs. observed haze index for selected days and Class I areas.

Figure 9: Relative Bias Between Maximum 8-hour Ozone Concentrations Predicted with CALGRID and Observations



Relative Bias (CALGRID minus Observed)

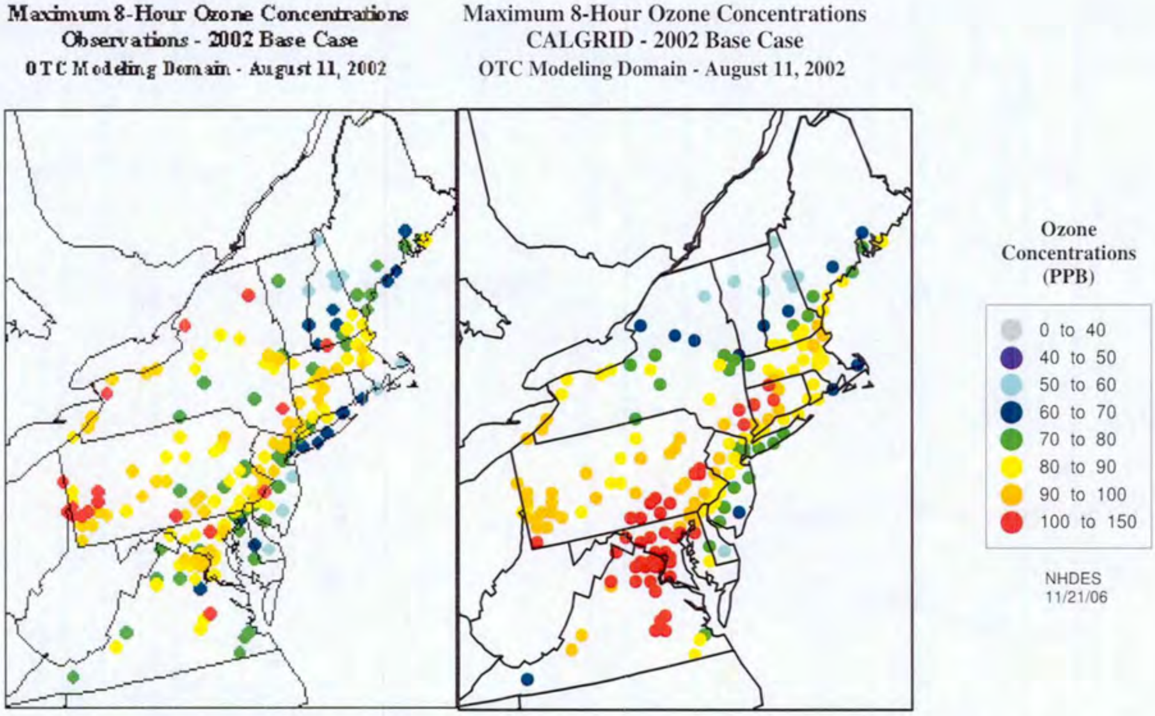
Based on Model Data for
July 30 - August 12, 2002
2002 Base Case Emissions
versus Observed Data

Green Circles are where
CALGRID Underpredicts

Red Triangles are where
CALGRID Overpredicts

NHDES 11/21/06

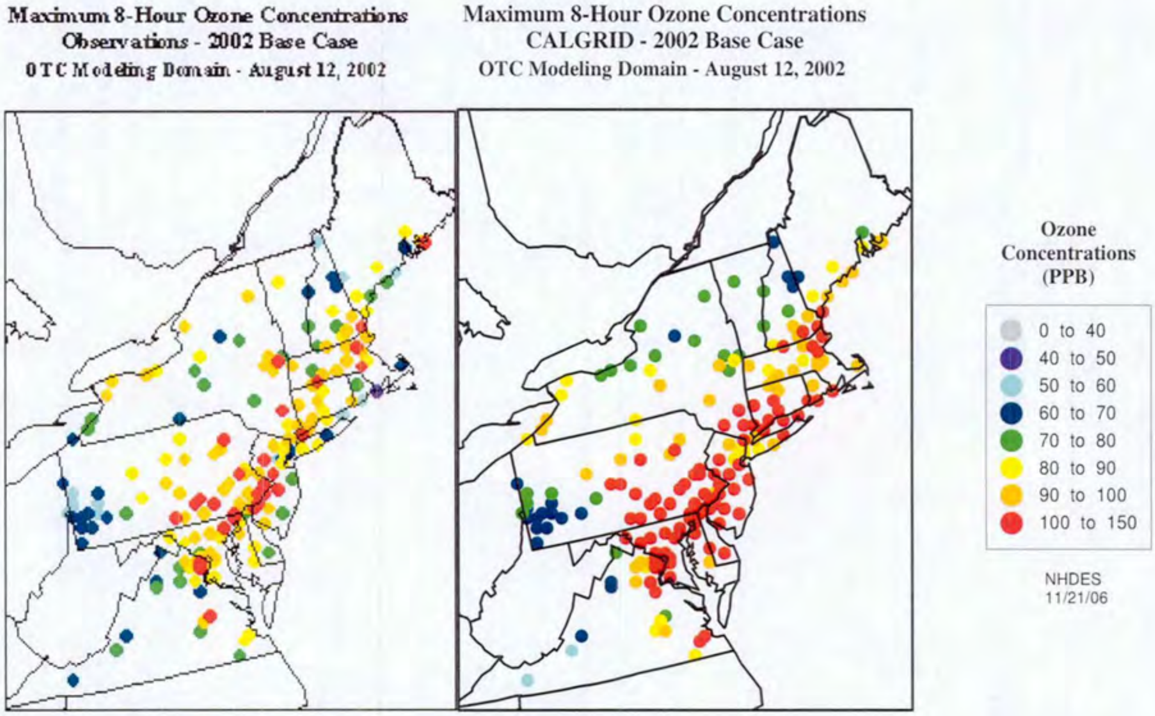
Figure 10: Comparison of Maximum 8-hour Ozone Concentrations for August 11, 2002



Maximum 8-Hour Ozone Concentrations
Observations - 2002 Base Case
OTC Modeling Domain - August 11, 2002

Maximum 8-Hour Ozone Concentrations
CALGRID - 2002 Base Case
OTC Modeling Domain - August 11, 2002

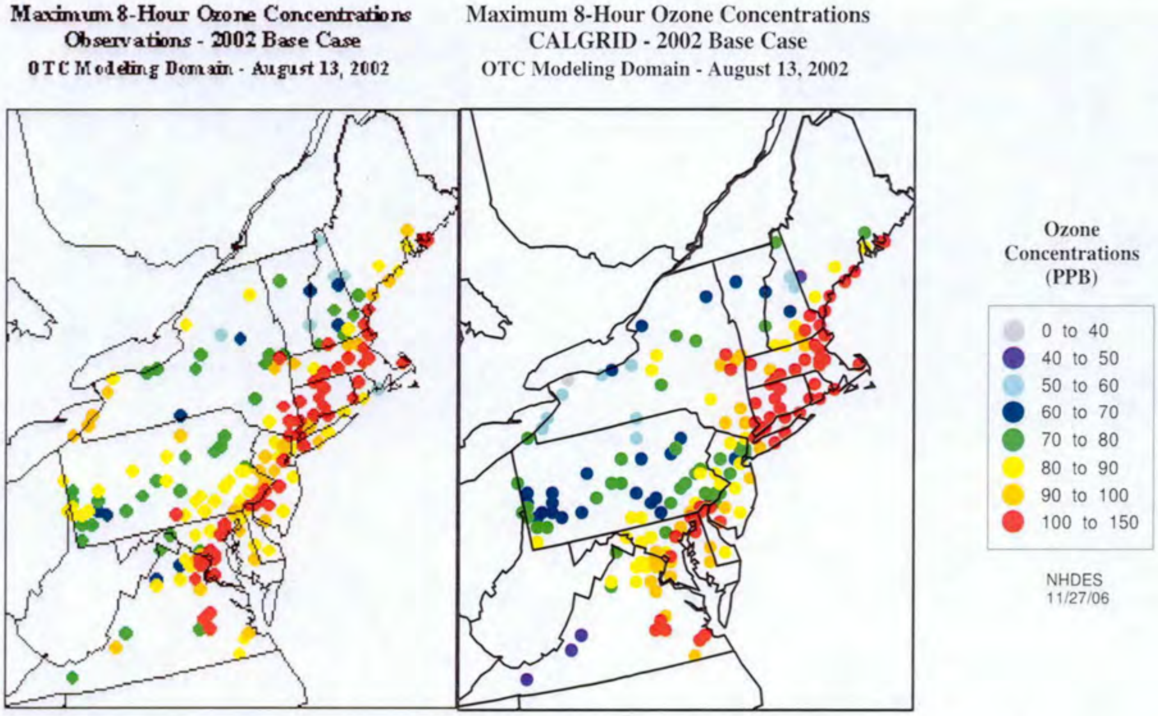
Figure 11: Comparison of Maximum 8-hour Ozone Concentrations for August 12, 2002



Maximum 8-Hour Ozone Concentrations
Observations - 2002 Base Case
OTC Modeling Domain - August 12, 2002

Maximum 8-Hour Ozone Concentrations
CALGRID - 2002 Base Case
OTC Modeling Domain - August 12, 2002

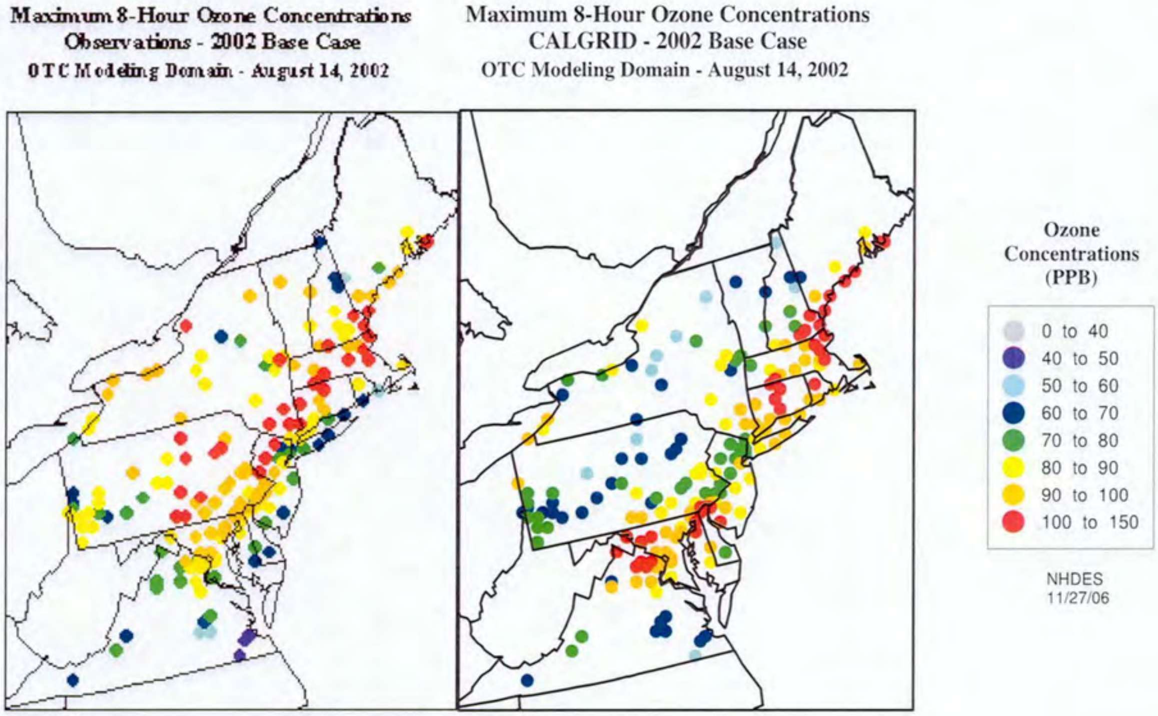
Figure 12: Comparison of Maximum 8-hour Ozone Concentrations for August 13, 2002



Maximum 8-Hour Ozone Concentrations
Observations - 2002 Base Case
OTC Modeling Domain - August 13, 2002

Maximum 8-Hour Ozone Concentrations
CALGRID - 2002 Base Case
OTC Modeling Domain - August 13, 2002

Figure 13: Comparison of Maximum 8-hour Ozone Concentrations for August 14, 2002



Maximum 8-Hour Ozone Concentrations
Observations - 2002 Base Case
OTC Modeling Domain - August 14, 2002

Maximum 8-Hour Ozone Concentrations
CALGRID - 2002 Base Case
OTC Modeling Domain - August 14, 2002

Figure 14: Comparison of Maximum 24-hour PM2.5 Concentrations for July 31, 2002

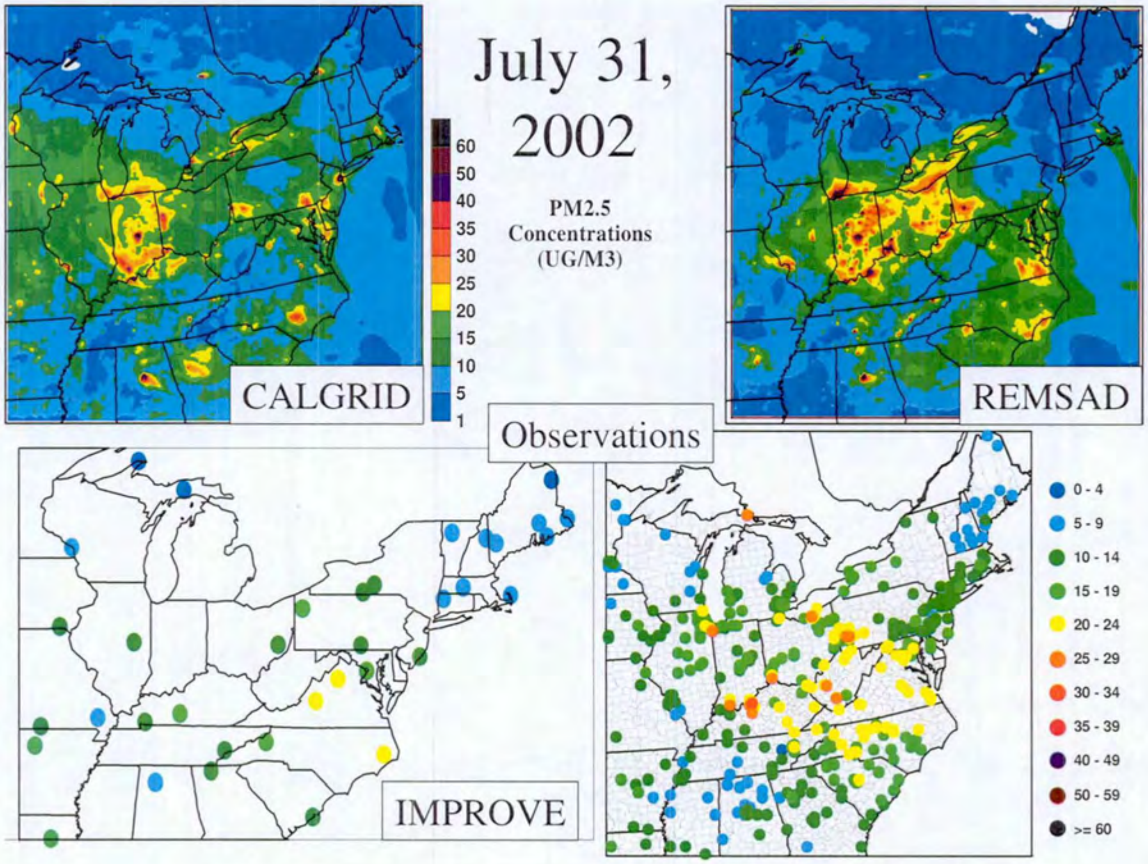


Figure 15: Comparison of Maximum 24-hour PM2.5 Concentrations for August 3, 2002

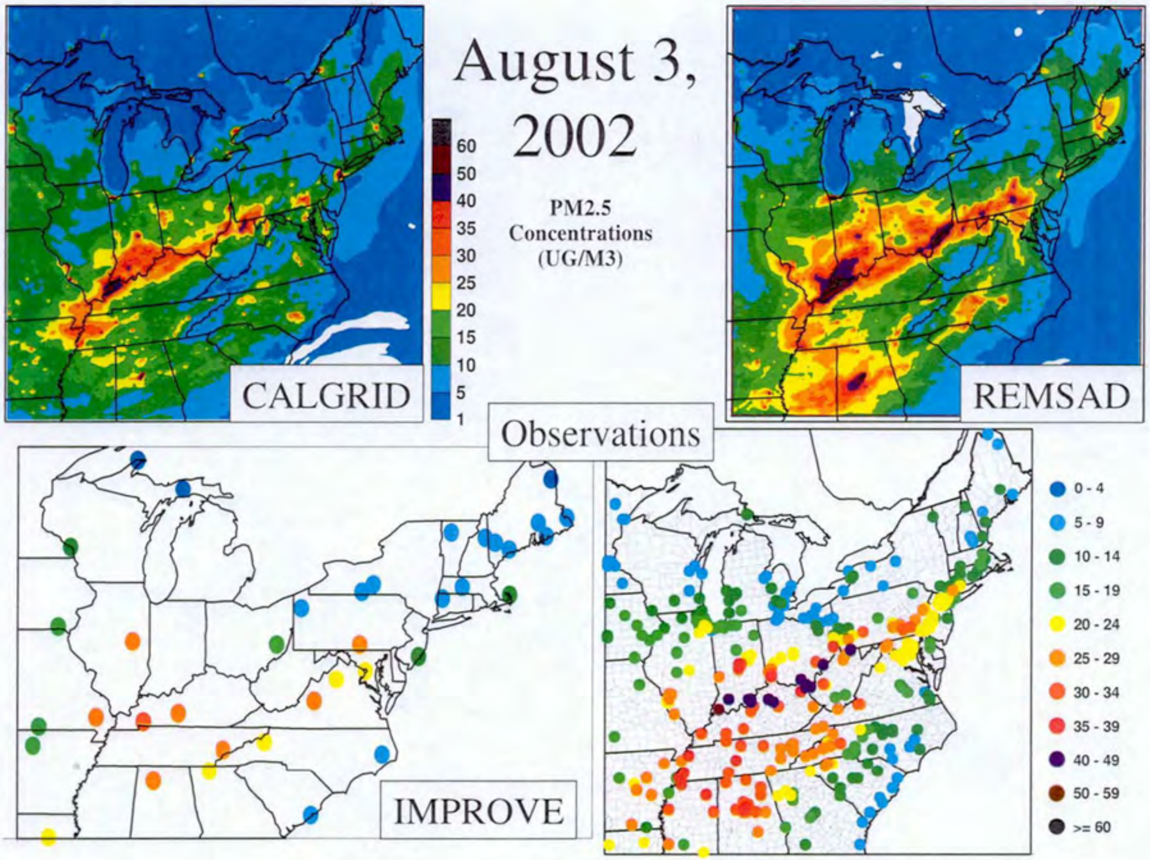


Figure 16: Comparison of Maximum 24-hour PM2.5 Concentrations for August 6, 2002

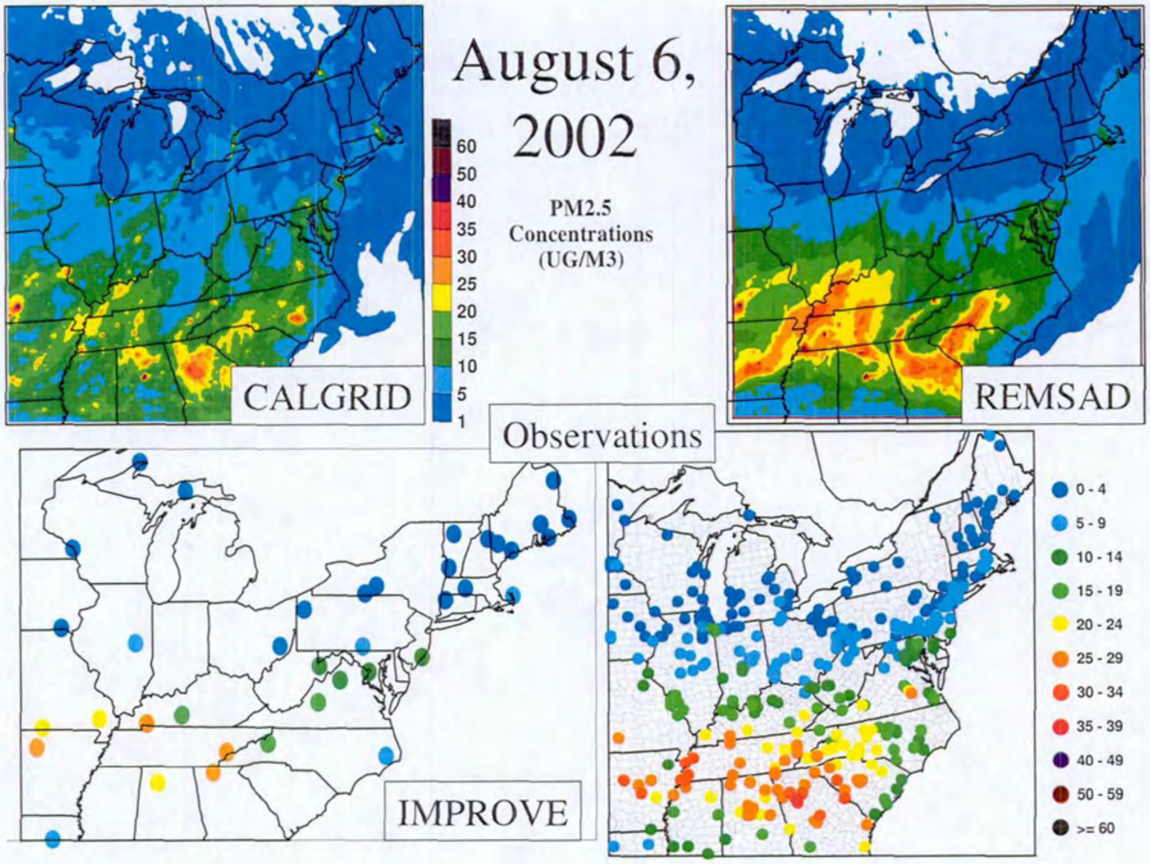


Figure 17: Comparison of Maximum 24-hour PM2.5 Concentrations for August 9, 2002

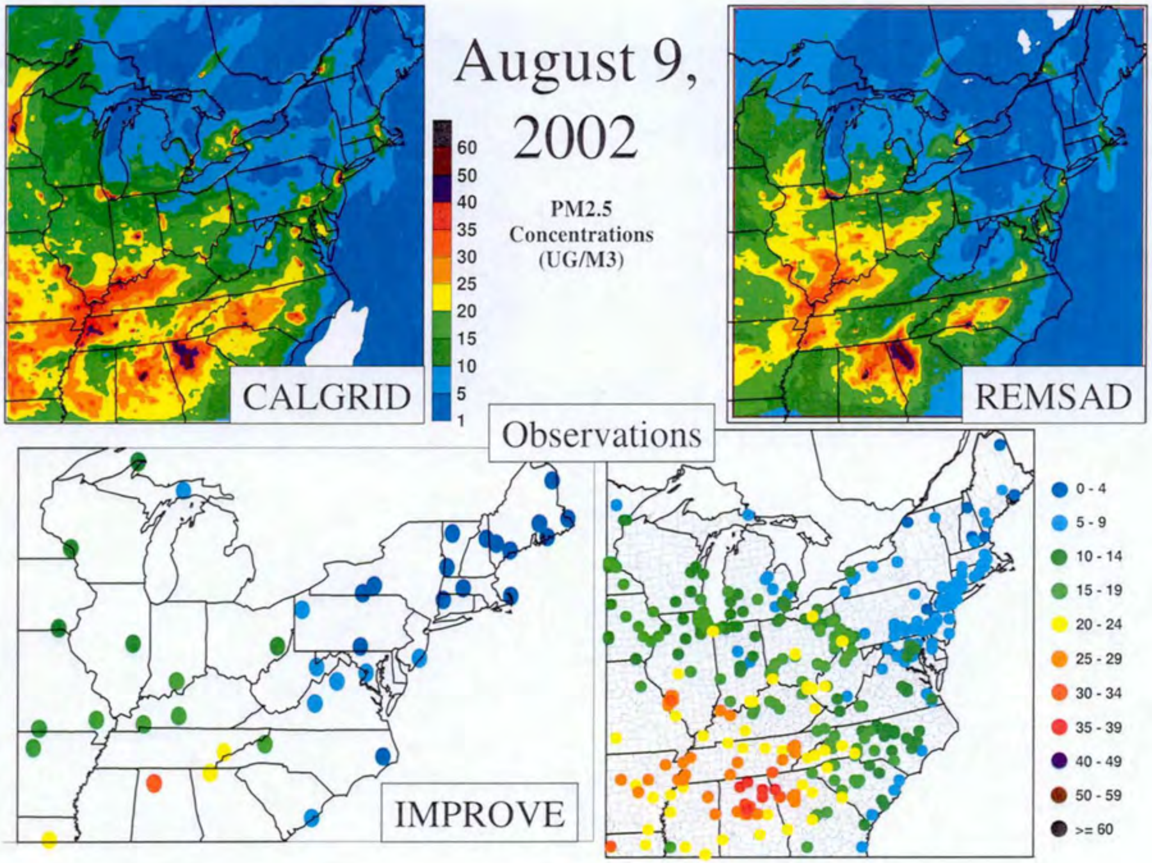


Figure 18: Comparison of Maximum 24-hour PM2.5 Concentrations for August 12, 2002

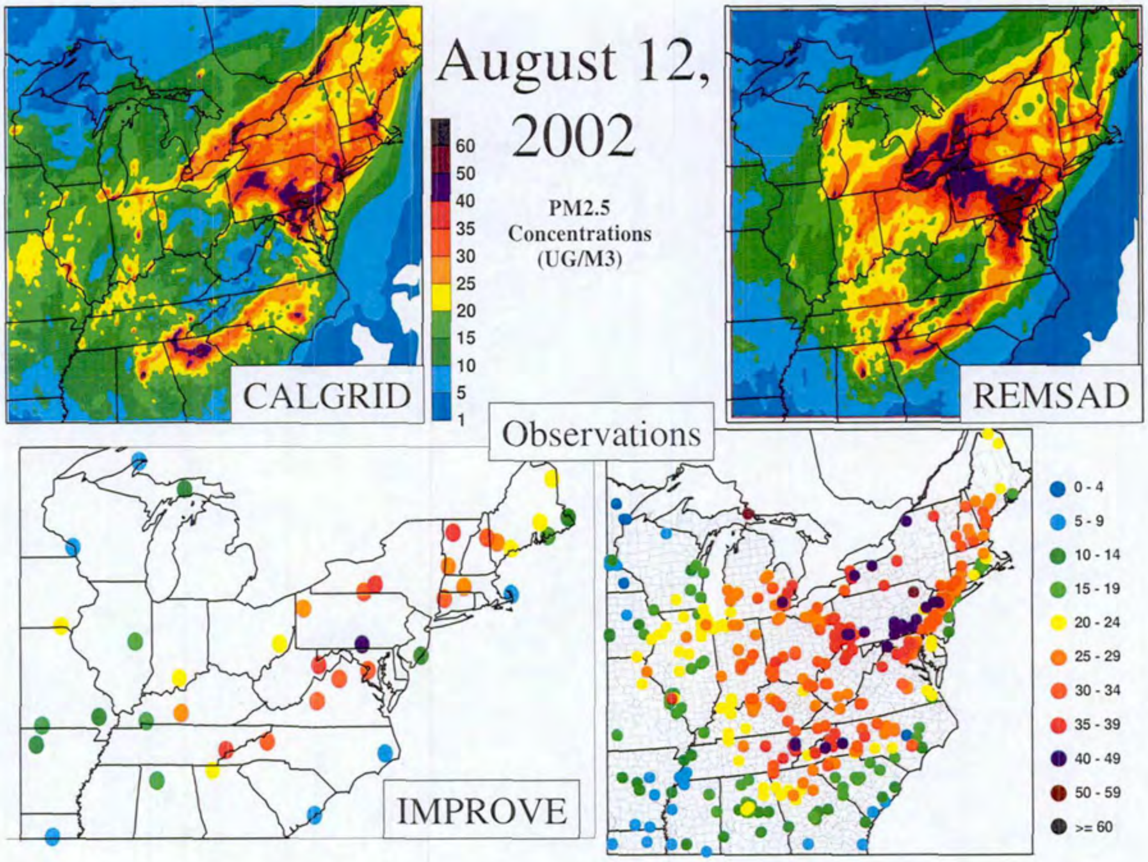


Figure 19: Comparison of Maximum 24-hour PM2.5 Concentrations for August 15, 2002

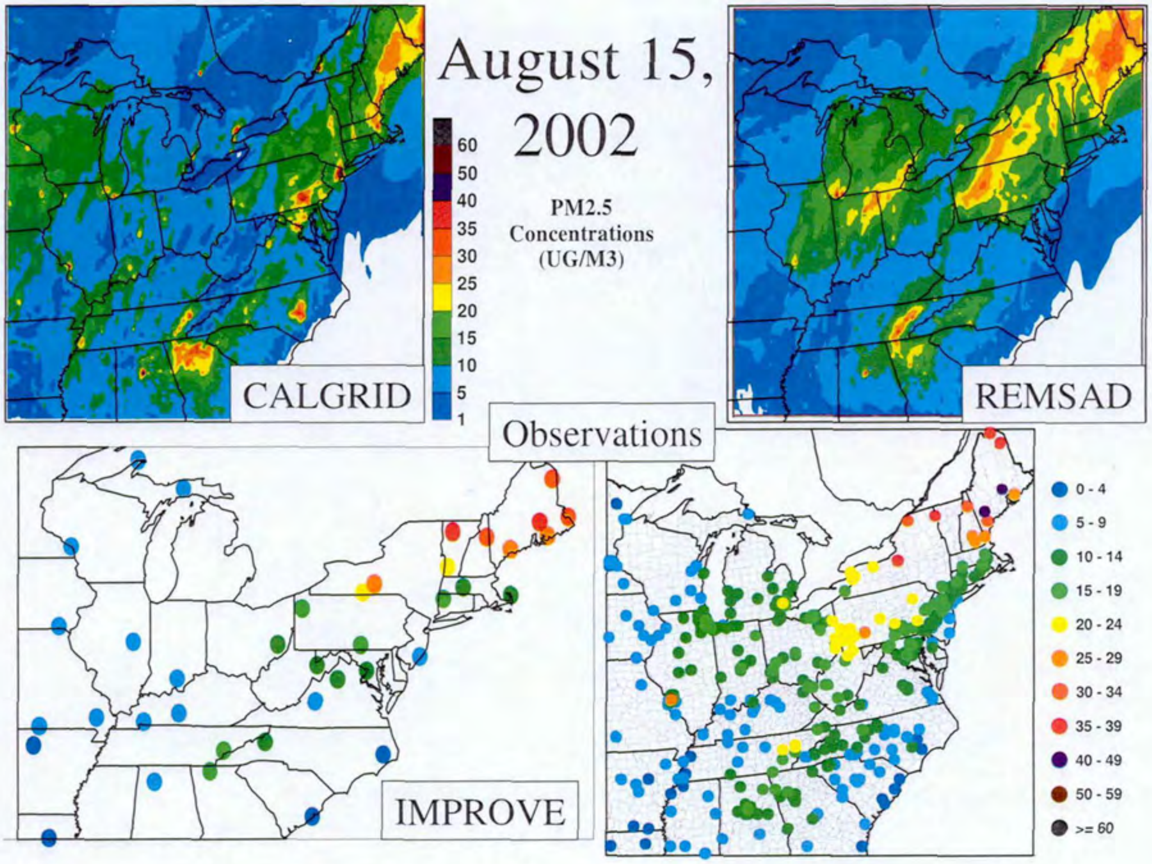
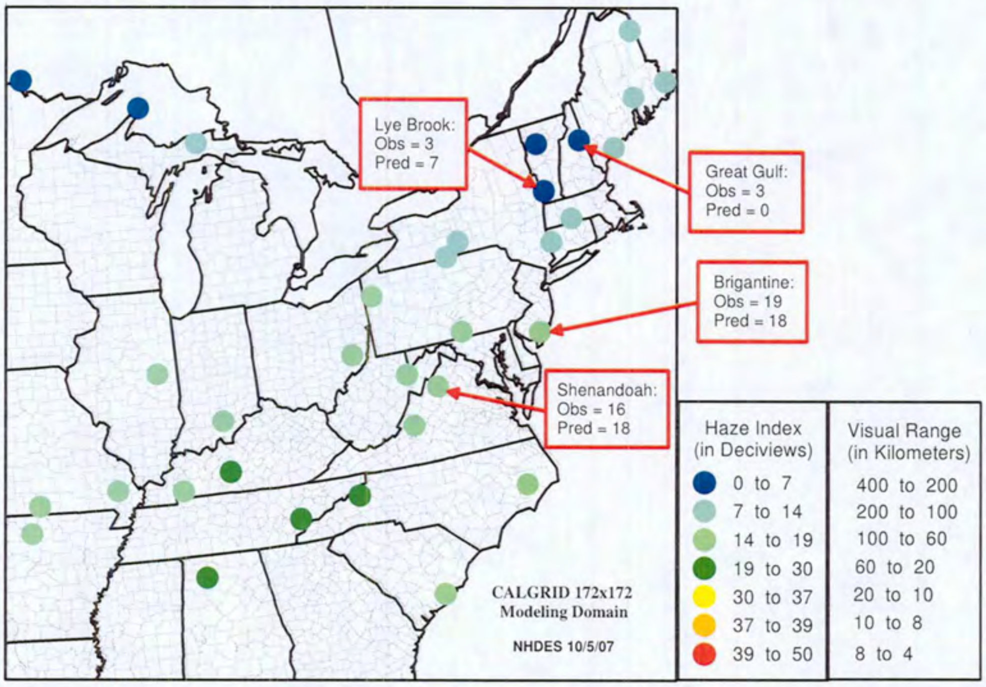


Figure 20: Comparison of Observed and Predicted Haze Index for May 14, 2002

Observed Haze Index at IMPROVE Monitors for May 14, 2002
(in Deciviews)


Lye Brook:
Obs = 3
Pred = 7

Great Gulf:
Obs = 3
Pred = 0

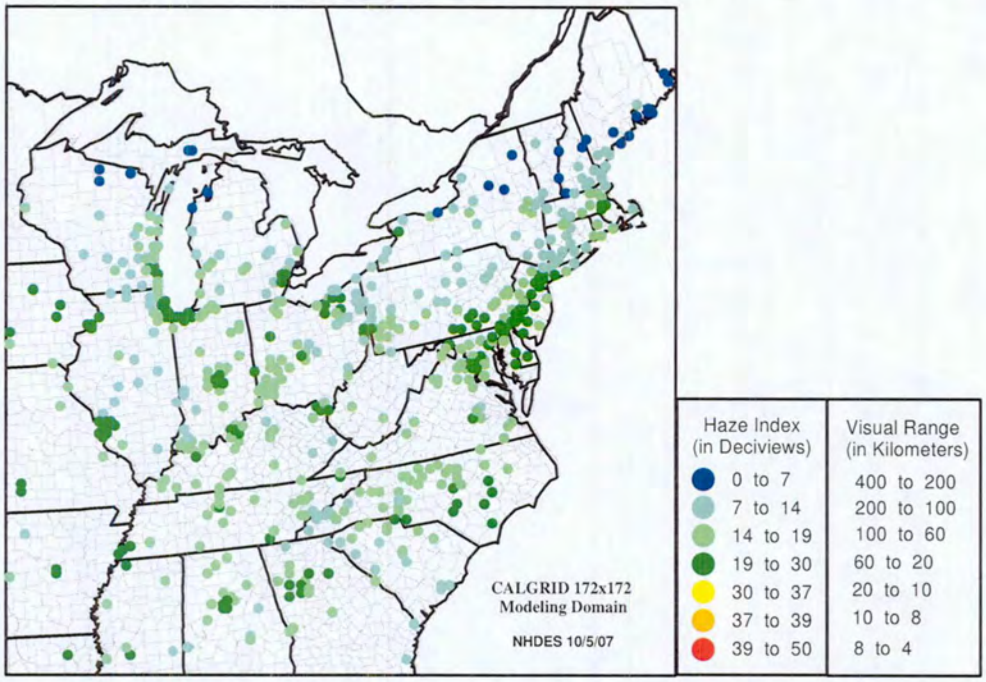
Brigantine:
Obs = 19
Pred = 18

Shenandoah:
Obs = 16
Pred = 18

CALGRID 172x172
Modeling Domain

NHDES 10/5/07

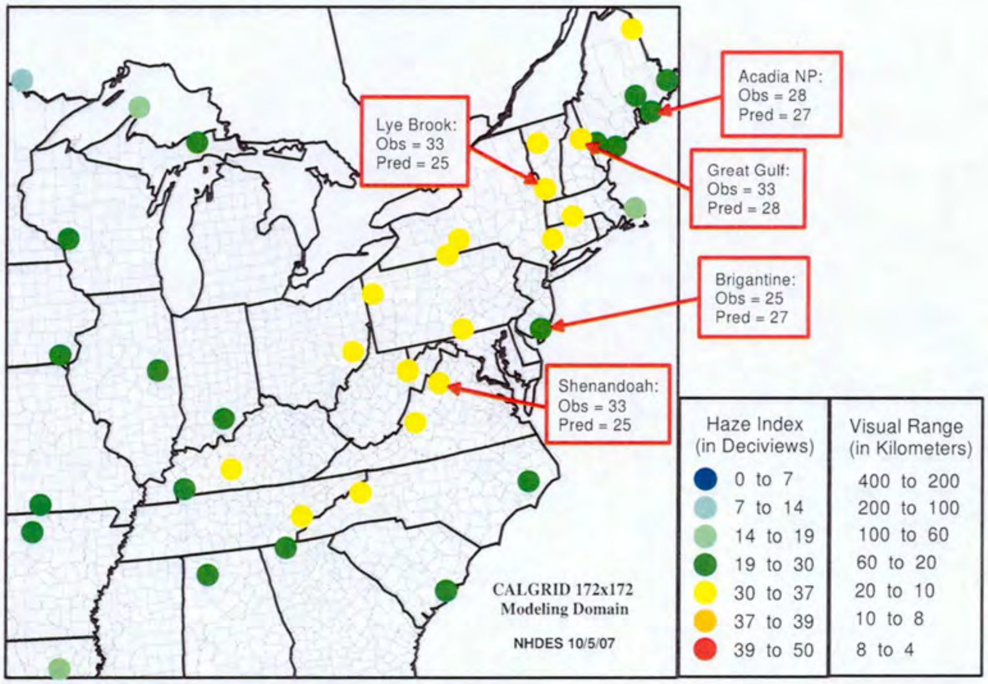
CALGRID Predicted Haze Index at Ozone Monitors for May 14, 2002
(in Deciviews)


CALGRID 172x172
Modeling Domain

NHDES 10/5/07

Figure 21: Comparison of Observed and Predicted Haze Index for August 12, 2002

Observed Haze Index at IMPROVE Monitors for August 12, 2002
(in Deciviews)



Acadia NP:
Obs = 28
Pred = 27

Lye Brook:
Obs = 33
Pred = 25

Great Gulf:
Obs = 33
Pred = 28

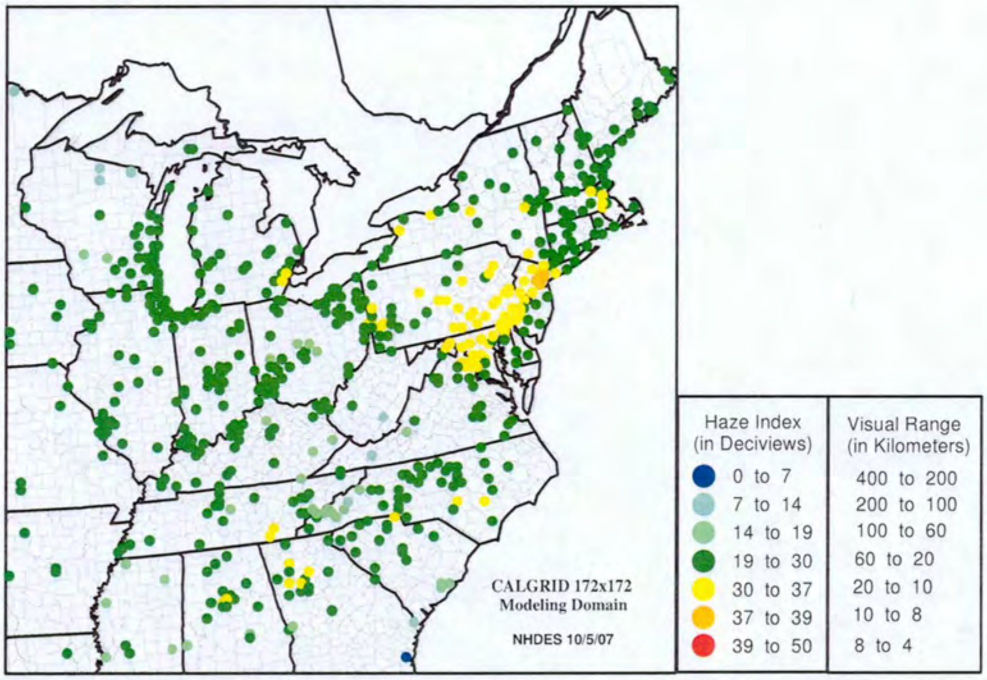
Brigantine:
Obs = 25
Pred = 27

Shenandoah:
Obs = 33
Pred = 25

CALGRID 172x172 Modeling Domain

NHDES 10/5/07

CALGRID Predicted Haze Index at Ozone Monitors for August 12, 2002
(in Deciviews)



CALGRID 172x172 Modeling Domain

NHDES 10/5/07

Figure 22: Comparison of Predicted and Observed Haze Index at Acadia National Park, ME

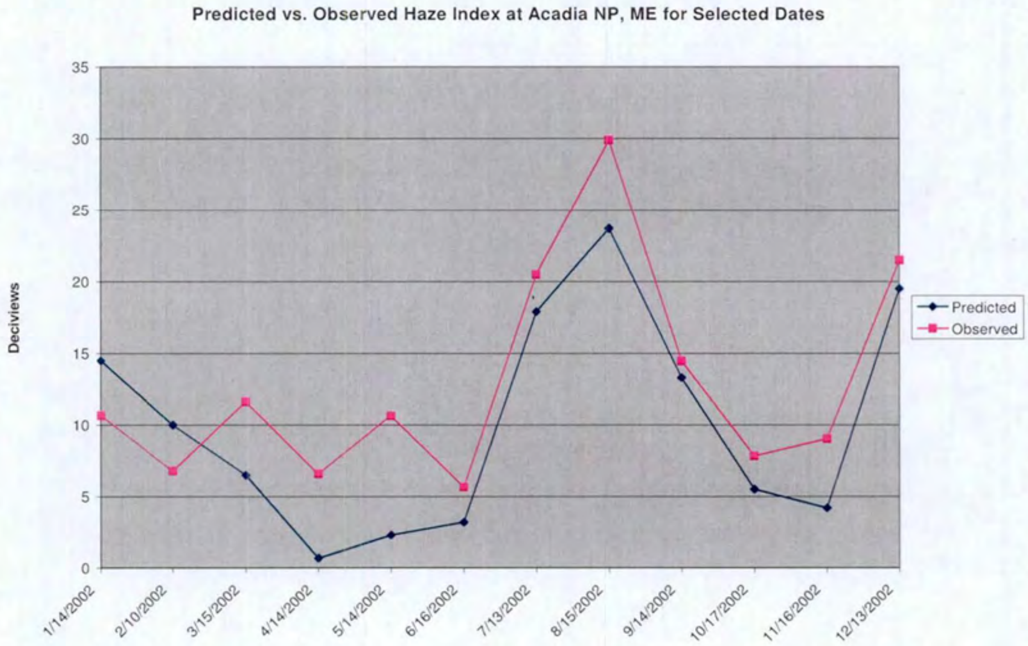


Figure 23: Comparison of Predicted and Observed Haze Index at Great Gulf Wilderness Area, NH

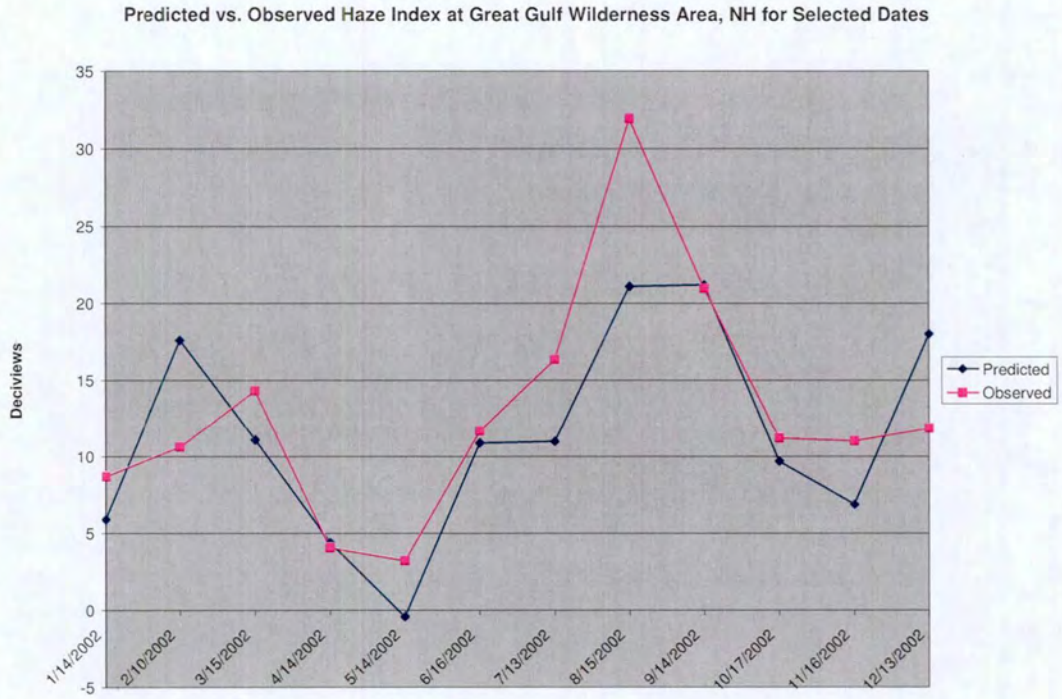


Figure 24: Comparison of Predicted and Observed Haze Index at Brigantine National Wildlife Refuge, NJ

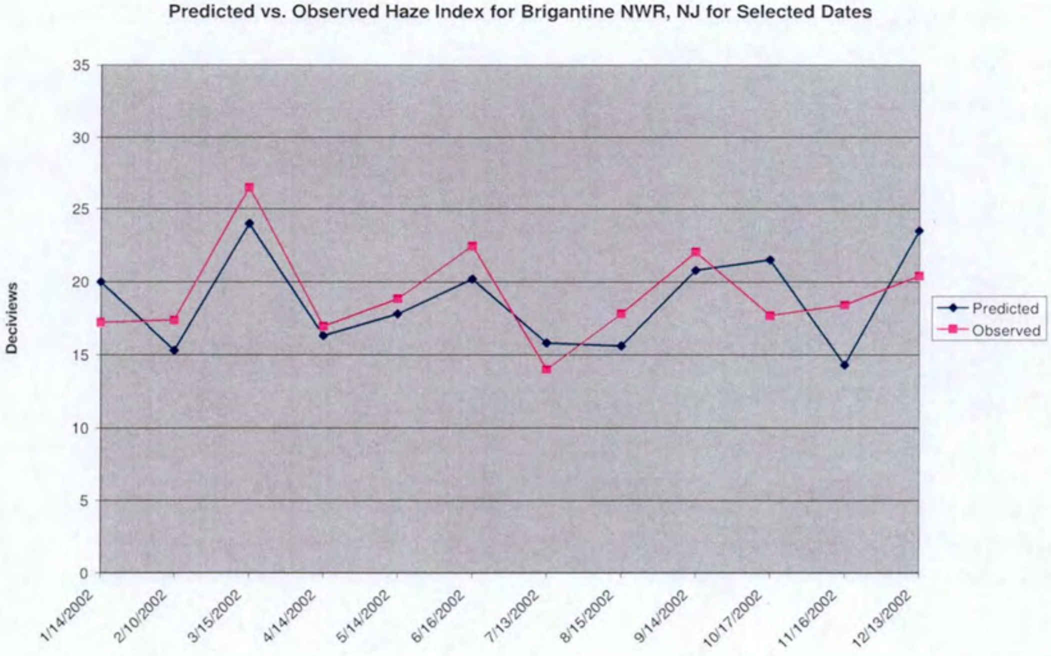


Figure 25: Comparison of Predicted and Observed Haze Index at Addison Pinnacle, NY

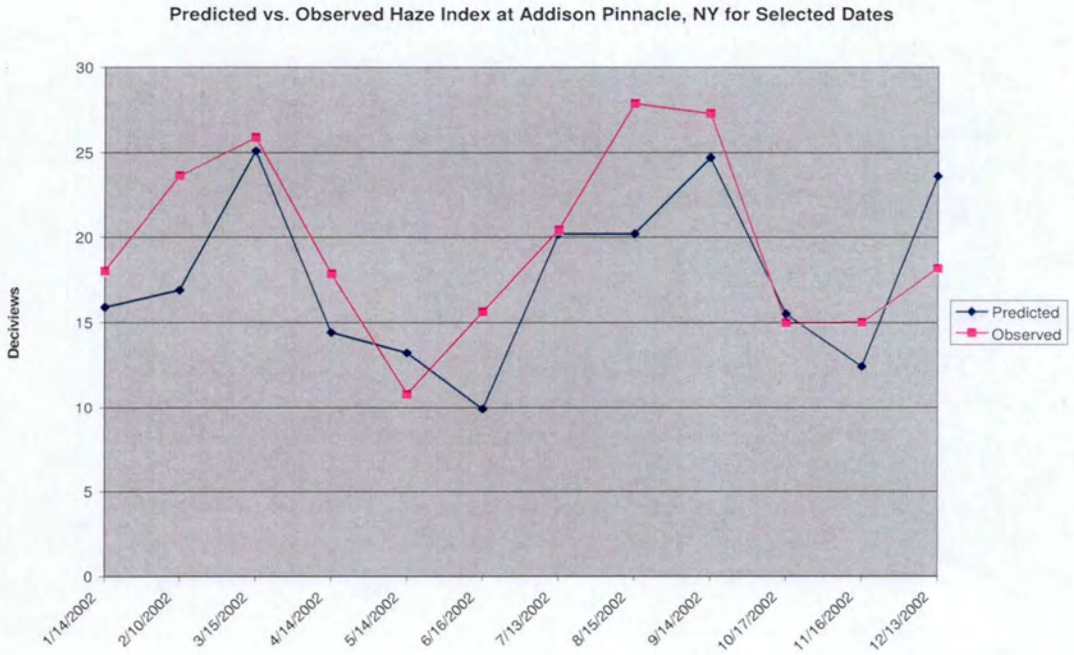


Figure 26: Comparison of Predicted and Observed Haze Index at Arendtsville, PA

Figure 27: Comparison of Predicted and Observed Haze Index at Lye Brook, VT

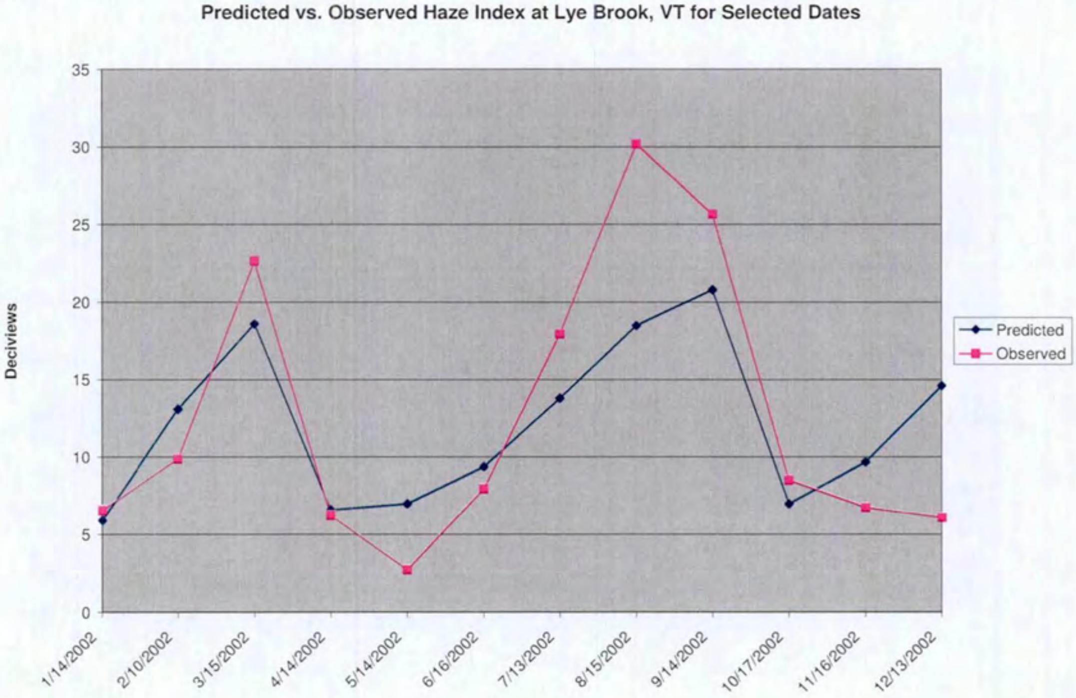
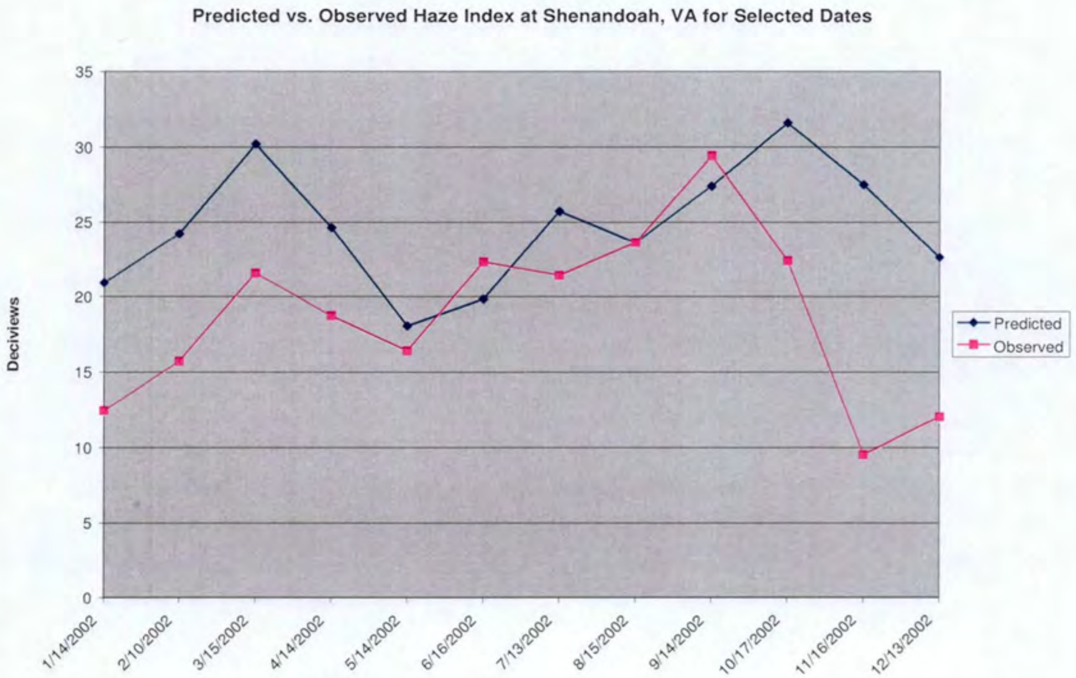


Figure 28: Comparison of Predicted and Observed Haze Index at Shenandoah, VA



6.0 CALGRID Model Runs

The OTC CALGRID modeling platform will be run for the 2002 Base Case, 2009 OTB/OTB, and 2009 BOTW. These simulations will be run for the full summer (May 15 to September 15, 2002) episode as well as for the shorter summer modeling episodes described earlier. A variety of control scenarios and sensitivity runs will be performed for the shorter episodes as requested by the OTC Modeling Committee or individual state agencies. The results of these runs may be used to evaluate, at a screening level, any additional emissions reductions that may be required, thus relieving the technical burden on the CMAQ modeling centers. CALGRID screening results may also be used in individual states' weight-of-evidence (WOE) analyses. If states request it, the CALGRID modeling platform will be delivered so that they may run additional modeling scenarios at their discretion.

ATTACHMENT V

Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region

September 1, 2006

1. Introduction

This technical support document aims to provide States with information useful in addressing agricultural and forestry smoke management in their State Implementation Plans (SIP). This document may also be useful for tribes in MANE-VU that choose to include smoke management issues in their Tribal Implementation Plans (TIP).

Each State must develop a long-term (10-15 years) strategy for making reasonable progress towards the national goal stated in 40 CFR 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 40 CFR section 51.308(d)(3)(v)(E), States must consider "smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the State for these purposes" in developing its long-term strategy.

Prior to developing their Regional Haze SIP/TIP, States/tribes must consider the air quality and visibility impacts of fires in the Region and evaluate whether their existing approaches to regulating fires are adequate. States must determine whether or not smoke management is necessary to mitigate the impacts of fires to meet the 2018 reasonable progress goals for Class I Areas. If smoke management policies are required for a particular Class I Area, then a smoke management program (SMP) should be initiated by the affecting States as appropriate. If smoke management policies are not required to meet 2018 goals, then States must include a brief discussion in their SIPs as to why a SMP is not required at this time. If States already have a SMP or other smoke management policy in place, then they are advised by the EPA to mention their policies in the SIP, whether or not they will be used to meet 2018 goals (see EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires," available online at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf).

A primary objective of this document is to provide information on the impact of fires on haze in the MANE-VU Region. Section 2 describes fires and smoke management in the MANE-VU Region, section 3 provides information on the air quality and visibility impacts of pollutants from wildland and prescribed fires, section 4 presents fire emissions inventory data, section 5 presents relevant MANE-VU source apportionment study results. While the contribution of fires to regional haze appears to be minor, fires may cause visibility problems on an episodic basis.

States are not required to include a SMP in their SIP. However, there are incentives for States to certify to the EPA that they have adopted and are implementing a basic SMP, whether or not the State chooses to incorporate the SMP into their SIP or make the SMP federally enforceable. Section 6 describes existing SMPs in the Region, provides an explanation of the incentives for States, and briefly explains the necessary elements in a basic SMP. Section 7 summarizes the key points presented in this paper.

2. Fires and Smoke Management in the MANE-VU Region

While some of the fires that occur in the MANE-VU Region are subject to SMPs, others are not. The definitions provided in this section are consistent with the descriptions included in the EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires" (prepared in 1998 and available online at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf), and the Western Regional Air Partnership's "Policy for Categorizing Fire Emissions" (prepared in 2001 and available online at www.fs.fed.us/pnw/fera/research/FirePolicy.pdf). Agricultural and forestry smoke management applies to all fires that are managed to achieve resource benefits, regardless of the cause of ignition (e.g. deliberate to meet specific objectives, lightning, arson, accidental, etc.) or the purpose of the fire (resource management, hazard reduction, etc.). Agricultural fires include all fires ignited by management actions to achieve benefits on agricultural land, such as croplands and pasture. Prescribed fires include all fires ignited by management techniques to achieve benefits on land other than agricultural land. Prescribed fires can be used for managing forests or rangeland, land on which the historic climax plant community is predominantly grasses, grass-like plants, forbs, or shrubs. Managed burning of logging debris, sometimes called slash burning, may also be used for forest management. Land managers may also manage naturally ignited fires to achieve resource benefits if the proper requirements have been met in the Fire Management Plan. These fires are termed Wildland Fire Use.

Naturally ignited fires in areas without plans for wildland fire use are considered unwanted fires or "wildfires" and are not covered by agricultural and forestry smoke management. Wildfires include any unwanted, non-structural fires that occur on wildlands, where there are a limited number of structures, or agricultural lands. Wildfires may be ignited by lightning, escaped prescribed fires, arson, or accidents, such as fireworks, cigarettes, escaped campfires, or vehicle fires, and are suppressed by management action. High pollutant concentrations attributable to wildfires can be treated as due to a natural event under EPA's Natural Events Policy. Under this policy, EPA may use its discretion not to redesignate areas as nonattainment if the State develops and implements a plan to respond to the health impacts of natural events.

Residential, industrial, and commercial/institutional wood combustion, open burning, slash burning, and structure fires are also not covered by SMPs. Residential industrial, and commercial/institutional wood combustion includes the burning of wood in indoor fireplaces and woodstoves and outdoor equipment. Open burning activities can occur at residential, commercial, or industrial sites and involve the burning of yard waste, including various types of plants and plant growth.

Emissions inventory results from 2002 (see section 4) show that the majority of fire emissions in the MANE-VU Region are from residential wood combustion. The Region is not prone to wildland fires due to vegetation types and relatively abundant rainfall. Agricultural and prescribed burning are also uncommon in the Region.

Typically, wood smoke is not detected in large amounts at monitoring sites in the MANE-VU Region. Several source apportionment studies that have been conducted in the MANE-VU Region show that wood smoke is a small to moderate contributor to fine particle pollution at monitoring sites (see section 5). Most source apportionment studies cannot distinguish between different types of fires, but smoke from agricultural and forestry activities is unlikely to be significant in the MANE-VU Region.

There are a few documented examples of wildfires producing large quantities of wood smoke and causing visibility impairment in MANE-VU Class I Areas. These fires have typically occurred outside the Region. For example, the July 7, 2002 Quebec Fires resulted in the largest one-day visibility impairment recorded at MANE-VU monitoring sites in recent years.

3. Air Quality and Visibility Impacts of Pollutants from Wildland and Prescribed Fires

Recent management strategies for some Federal, State, and Tribal wildlands involve increased use of wildland and prescribed fires to improve the health of the ecosystems and minimize risks to public and fire fighter safety. However, smoke from wildland and prescribed fires can contribute significantly to regional haze. To address issues associated with how fire managers can effectively use fires to help ecosystems while minimizing visibility impairment, the U.S. EPA, in partnership with other agencies, issued the "Interim Air Quality Policy on Wildland and Prescribed Fires," available on-line at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf. The following description of air quality and visibility considerations includes information presented in this document. Other types of fires that involve vegetative burning (e.g. agricultural fires, open burning, residential wood combustion, etc.) have similar affects on air quality and visibility.

Burning wildland vegetation emits several air pollutants, including particles, NO_x, CO, and organic compounds. The quantity and composition of the emissions depend on the type of material burned, its moisture content, and the combustion temperature. Particle pollution from wildland and prescribed fires includes particles that have a diameter as large as 100 µm. Particles that have diameter less than 10 µm are referred to as PM_{10} and fine particles that have a diameter less than 2.5 µm are referred to as $PM_{2.5}$. There is evidence that particle pollution has serious health effects, particularly for sensitive populations.

Particle pollution also diminishes visibility because particles and gases scatter and absorb light. Fine particles scatter light more efficiently than coarser particles per unit mass. The fine particles that primarily contribute to visibility impairment include sulfates, nitrates, organic compounds, soot, and soil dust. As humidity increases, light scattering efficiencies also increase due to the adsorption of water on fine particles. Since the eastern United States typically has higher relative humidities than the West, the naturally occurring visual range in the East is only 105 to 190 km while the range in the West is 190 to 270 km. Visibility impairment affects the enjoyment of daily activities. Diminished visibility in mandatory Class I Federal areas, "Areas of Great Scenic Importance," is particularly important because haze affects the public's appreciation of scenic views and tourism.

4. MANE-VU Fire Emissions Inventories

4.1 Analysis of the 2002 MANE-VU Modeling Inventory

MANE-VU compiled a regional emissions inventory for 2002 for use in modeling. The inventory includes fire emissions from each State in the MANE-VU region. States provided fire emissions as annual county level estimates. Some States also provided estimates for seasonal and/or daily emissions, but those data are not shown here. Emissions data was collected for CO, NH_3, NO_x, $PM_{2.5}$, PM_{10}, SO_2, and VOC, but not all States provided data for all pollutants or source category codes (SCCs). Fire emissions include industrial wood combustion, commercial/institutional wood combustion, residential wood combustion, open burning, agricultural burning, forest fires, slash burning, prescribed burning, and structure fires.

The data presented here are from Version 3.0 of the MANE-VU Modeling Inventory, with updated residential wood combustion data from New York. Values for State emissions were calculated by adding the county level annual data.

Massachusetts, New Hampshire, and Vermont provided data on industrial wood combustion (SCC 2102008000). Maine, Massachusetts, New Hampshire, and New York provided data on commercial/institutional wood combustion (SCC 2103008000).

All MANE-VU States and the District of Columbia provided data on residential wood combustion from indoor fireplaces and woodstoves. Connecticut, Delaware, Maine, Maryland, Massachusetts, and New Hampshire provided data for total woodstoves and fireplaces (SCC 2104008000). The District of Columbia, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states. Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, and New Hampshire have data for outdoor equipment (SCC 2104008070). There is no data in Version 3.0 for outdoor equipment from New Jersey, New York, Pennsylvania, Rhode Island, or Vermont.

All States except Connecticut reported data for open burning of yard waste leaf species (SCC 2610000100), yard waste brush species (SCC 2610000400), and household waste (SCC 2610030000). Connecticut, Delaware, Maryland, New Jersey, Pennsylvania, and Vermont included data for open burning of land clearing debris (SCC 2610000500). Only Pennsylvania reported data for industrial open burning (SCC 2610010000) and commercial/institutional open burning (SCC 2610020000). The District of Columbia did not report emissions for any of the open burning categories.

Maine, New Jersey, and Vermont provided emissions data on Agricultural Field Burning (SCC 2801500000), which involves whole fields set on fire and includes the burning of all crop types. No States in the MANE-VU region reported emissions from Agricultural Propaning (SCC 2801501000), which involves tractor-pulled burners being used to burn stubble only, or Agricultural Stack Burning (SCC 280150200), which involves straw stacks being moved from the field prior to burning.

All MANE-VU States provided some emissions data for forest (wildland) fires (SCC 2810001000). The District of Columbia did not report forest fire emissions for 2002. Maine and Maryland reported emissions data for managed/slash burning (SCC 2810005000), which often involves the burning of logging debris. Delaware, the District of Columbia, Maine, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island included emissions data on prescribed burning for forest management (SCC 2810015000). Only Maine reported emissions from prescribed burning of rangeland (SCC 2810020000), and the amounts of all pollutants were negligible. All MANE-VU States and the District of Columbia provided emissions data for structure fires (SCC 2810030000).

Relative to other area sources, wood burning is a large source of CO, a moderate source of NO_x, PM_{10}, $PM_{2.5}$, and VOC, and a minor source of NH_3 and SO_2 in the MANE-VU Region. Emissions of CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOC in the MANE-VU Region by wood burning category are included in Table 1. The data for MANE-VU States and the District of Columbia that were used to calculate MANE-VU totals are included in tables in the appendix.

Table 1: Wood Smoke Emissions (Tons/Year) in the MANE-VU Region by source category (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Industrial Wood Comb.[1]	19492.3	0	9974.9	15088.3	13060.7	2604.2	572.6
Comm./Inst. Wood Comb.[2]	5180.6	0	1654.9	659	567.2	35.2	50.1
Residential Wood Comb.[3]	902117.8	5704.4	11078.2	119147.5	113594.6	1695.8	566531.7
Agricultural Burning[4]	3029.8	0	54.2	208.4	207.8	0.2	363.4
Wildland Fires[5]	18381.2	237.4	469.5	2406.4	2179.1	18	1967
Managed/Slash Fires[6]	42.1	0	1.2	5.1	5.1	0	5.7
Prescribed Fires[7]	13609.3	70.9	196.2	1361.5	1178.8	55.4	776.6
Structure Fires[8]	4034.9	0	162.5	939.9	900.4	532.5	751.9
Open Burning[9]	189504	152	7069.1	24597.1	23713.4	428.2	17174.2
All Fires	1,155,392	6,164.7	30,660.7	164,413.2	155,407.1	5,369.5	588,193.2

[1] SCC 2102008000; [2] SCC 2103008000; [3] SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4] SCC 2801500000; [5] SCC 2810001000; [6] SCC 2810005000; [7] SCC 2810015000 and SCC 2810020000; [8] SCC 2810030000; [9] SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

While emissions from wood burning activities comprise a significant portion of MANE-VU area source emissions, only a small portion of wood burning activities are relevant to agricultural and forestry smoke management. Agricultural, managed/slash, and prescribed burning are subject to SMPs. On rare occasions, forest (wildland) fires and structure fires that are permitted to burn are also covered by SMPs. Table 2 shows the sum of agricultural, managed/slash, prescribed, structure, and wildland fires, the total area source emissions, and the percentage of area emissions from wood burning for each pollutant.

Table 2: Wood Smoke Emissions (Tons/Year) in the MANE-VU Region by source category (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

MANE-VU	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Agricultural[1], Wildland[2], Managed/Slash[3], Prescribed[4], and Structure[5] Fires	39,097	308	884	4,921	4,471	606	3,865
Total Area Source Emissions[6]	1,325,853	249,795	262,477	1,455,311	332,729	316,357	1,528,141
% of Area Source Emissions	**2.95%**	**0.12%**	**0.33%**	**0.33%**	**1.34%**	**0.19%**	**0.25%**

[1]SCC 2801500000; [2]SCC 2810001000; [3]SCC 2810005000; [4]SCC 2810015000 and SCC 2810020000; [5]SCC 2810030000, [6]Data from the summary developed by E.H. Pechan and Associates, Inc. of area source emissions included in the 2002 MANE-VU Modeling Inventory, Version 2.0.

While fire emissions are not significant sources in any of the MANE-VU States or the District of Columbia, some States have slightly greater emissions than others. Figure 1 shows emissions from agricultural, managed/slash, prescribed, forest, and structure fires by State.

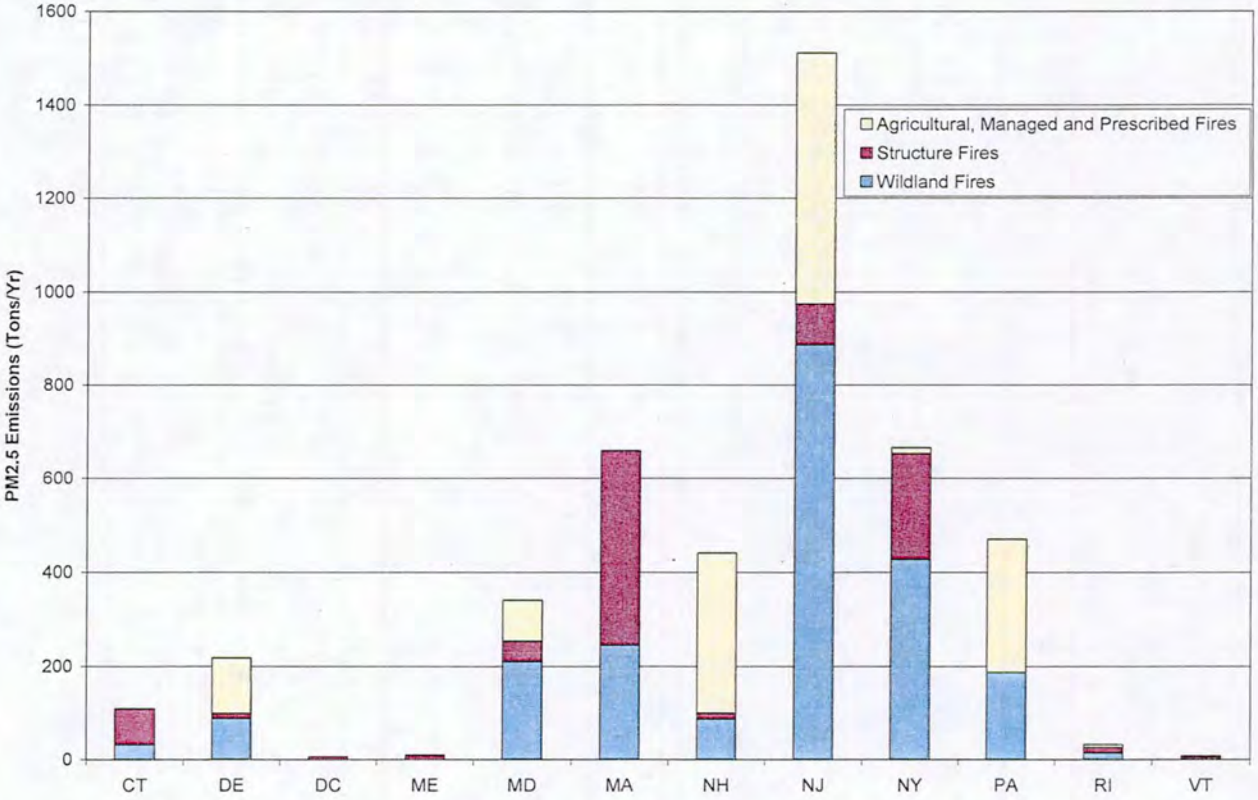


Figure 1: Fire emissions in the MANE-VU Region by state. (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Fires only account for approximately 2% of CO area source emissions, 1% of $PM_{2.5}$ area source emissions, and less than 1% of NH_3, NO_x, PM_{10}, SO_2, and VOC area source emissions in the MANE-VU Region. Considering that most forest and structure fires in the Region are unwanted "wildfires," fires used for resource benefits are a very minor contributor to regional area source emissions.

Other sources of wood smoke are significantly larger sources of pollutants than fires used for resource benefits. Figure 2 shows the relative contributions of $PM_{2.5}$ emissions from the various wood burning source categories. The largest source categories for $PM_{2.5}$ are residential wood combustion (73%), open burning (15%), and industrial, commercial, and institutional wood combustion (9%). Structure fires and wildland fires, which are generally characterized as unwanted fires, only make up a minor portion of the wood burning emissions. Fires that are covered under SMPs, including fires due to agricultural, managed, and prescribed burning, comprise less than 1% of the total wood smoke emissions.

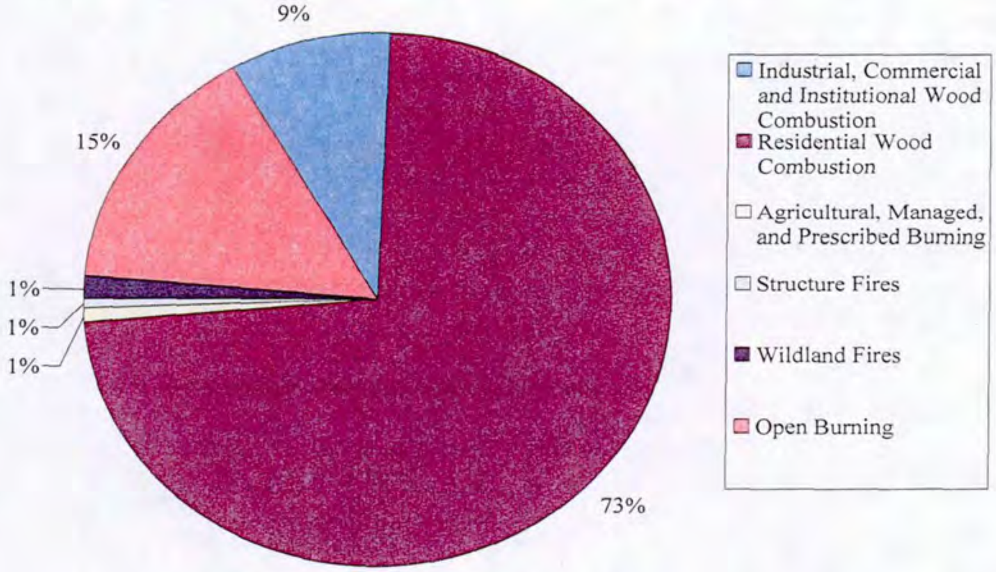


Figure 2: 2002 $PM_{2.5}$ Emissions from Wood Burning by Source Category (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated residential wood combustion data from New York)

4.2 Future Year Inventory Considerations

In setting reasonable progress goals and devising long term strategies, States must project the 2002 base year inventory to future years. Fire emissions are held constant from 2006 through 2018 for National Forests within the MANE-VU states. This is because variables such as weather, staff, budget, priorities, and other programs limit the Forest Services ability to project through 2018.

5. Relevant MANE-VU Source Apportionment Study Results

States must include a contribution assessment and pollution apportionment analysis in their regional haze SIPs. MANE-VU is in the process of using a weight of evidence approach that relies on several methods for assessing the contribution of different emissions to regional haze at federal Class I Areas. Preliminary findings of this work show that sulfate comprises one-half to two-thirds of $PM_{2.5}$ mass on the 20% haziest days and more than 40% of $PM_{2.5}$ mass on the 20% clearest days. Sulfates also have a much larger impact on visibility than the same mass of other pollutants. As a result, sulfates account for an even greater percentage of the particle–induced visibility impairment in the Region. The second most important contributor to $PM_{2.5}$ mass and also haze is organic carbon.

As part of the contribution assessment work, Serpil Kayin of MARAMA and Richard Poirot of the Vermont Department of Environmental Conservation summarized the results of studies that have used receptor-based models to apportion pollution sources at several sites within the Mid-Atlantic/Northeast Region and a few sites within the upwind or downwind influence area of the Region. The technical summary by Kayin and Poirot will appear as "Appendix B: Source Attribution by Receptor-Based Methods" in the MANE-VU document, *Tools and Techniques for Identifying Contributions to Regional Haze in the Northeast and Mid-Atlantic United States.* The most recent draft of Appendix B is available online at http://bronze.nescaum.org/Em/Haze-Contrib/AppendixB-04-07-05.pdf.

The primary goal of the receptor-based studies was to describe and quantify the major source categories that contribute to the observed $PM_{2.5}$ concentrations. Several methods were used to apportion $PM_{2.5}$ concentrations including mathematical receptor models and ensemble trajectory analysis techniques. Descriptions of the monitoring sites that were investigated by Kayin and Poirot are included in Table 3. For more information on the periods of data collection, analysis technique(s), and references, see the draft of "Appendix B: Source Apportionment by Receptor-Based Methods."

Table 3: Monitoring sites in the MANE-VU Region where source apportionment analyses have been conducted

Site	Location	Elevation (meters)	Type of Monitoring Network
Acadia National Park, ME	44 N, 68 W	150	IMPROVE
Lye Brook Wilderness, VT	43 N, 73 W	1010	IMPROVE
Underhill, VT	45 N, 73 W	400	IMPROVE
New York, NY (three sites in the Bronx, one site in Queens)	41 N, 74 W		Urban STN
Brigantine Wilderness, NJ	39 N, 74 W	15	IMPROVE
Baltimore-Washington Corridor (Fort Meade, MD)	39 N, 77 W	46	Site included in a University of Maryland study
Washington, DC	39 N, 77 W	30	McMillan IMPROVE
Shenandoah National Park, VA	39 N, 78 W	1098	IMPROVE
Jefferson/James River Face Wilderness Area, VA	38 N, 79 W	280	IMPROVE
Dolly Sodds Wilderness Area, WV	39 N, 79 W	1158	IMPROVE
Mammoth Cave National Park, KY	37 N, 86 W	248	IMPROVE
Great Smoky Mountains National Park, TN	36 N, 84 W	815	IMPROVE
Boundary Waters canoe area, MN	48 N, 91 W	524	IMPROVE
Charlotte, NC	35 N, 81 W	230	EPA Trends
Boston, MA (residential site in Watertown, MA)	42 N, 71 W		Site included in the Harvard Six Cities Study
Potsdam and Stockton, NY (one Potsdam site, one Stockton site)	47 N, 75 W 42 N, 79 W		Site included in a Clarkson University study
Toronto, Canada			Site located at the University of Toronto

The data presented in the report by Kayin and Poirot are source apportioned $PM_{2.5}$ mass and the percentage of $PM_{2.5}$ mass. While the sources for $PM_{2.5}$ and haze are the same, the relative importance of those sources on $PM_{2.5}$ concentration and visibility impairment differ somewhat. In addition to being related to $PM_{2.5}$ concentration, light extinction is also a function of the components of $PM_{2.5}$ and relative humidity. Thus, while source apportioned $PM_{2.5}$ mass data is highly relevant to regional haze, there are limitations to making direct comparisons. Certain pollutants, such as sulfate, make up a larger contribution to regional haze than to $PM_{2.5}$ mass.

The major sources of $PM_{2.5}$ identified were coal burning (primary and secondary sulfate aerosols), secondary organic matter from possibly mobile sources, nitrate aerosols, biomass burning (wood smoke and forest fires indicated by the presence of organic carbon, elemental carbon, and potassium), industrial sources (a variety of sources, including smelters, incinerators, and oil burning, indicated by the presence of elemental carbon and characteristic trace metals), a crustal source (dust and soil indicated by the presence of silicon, aluminum, calcium, iron, and titanium), and a sea salt source (identified by the presence of sodium and chloride).

A wood smoke or biomass burning source was identified at most of the rural sites, but was generally not detected or of small magnitude in larger urban areas, including Boston, New York City, Toronto, and Washington D.C. Wood smoke was also a negligible or low contributor (less than 10%) in Acadia National Park, Boundary Waters, Brigantine Wilderness, Charlotte, Dolly Sods Wilderness Area, Great Smoky Mountains National Park, and Potsdam and Stockton.

Wood smoke was identified as a significant source of average $PM_{2.5}$ mass (greater than 10%) in the Baltimore-Washington corridor, Lye Brook Wilderness, Mammoth Cave National Park, Shenandoah National Park, Jefferson/James River Face Wilderness Area, and Underhill. In Lye Brook Wilderness and Underhill, wood smoke was the second largest source, following regional secondary sulfate.

In the Lye Brook Wilderness Area, wood smoke comprised a relatively high percentage (35%) of the average $PM_{2.5}$ mass. However, the smoke source was not identified as especially important there on either the 20% best or worst visibility days.

Smoke also contributed significantly to the $PM_{2.5}$ mass at Underhill, VT. This source was found to make up a large portion (25%) of the $PM_{2.5}$ mass on the 20% clearest days but a smaller portion (7%) on the 20% dirtiest days. It was predicted that the site was influenced by Canadian fires.

In addition studies on source categories, there has also been work to investigate the source regions for wood smoke. Figure 3 is based on source apportionment and back trajectory results in the Eastern United States. The results for various IMPROVE sites are aggregated for the Northeast Region (Acadia National Park, Presidential Mountain Range, and Lye Brook Wilderness Area), the Mid-Atlantic Region (Washington D.C., Shenandoah National Park, and James River Face Wilderness Area), and the Southeast Region (Great Smoky Mountains National Park and Mammoth Cave National Park).

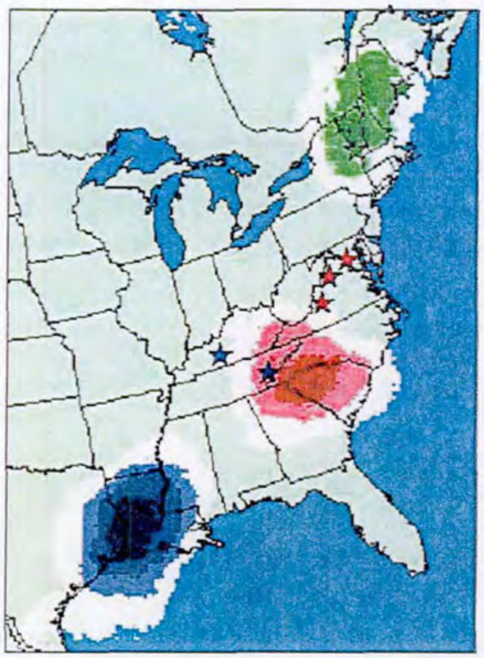


Figure 3: Wood smoke source regional aggregations (Source "Appendix B: Source Attribution by Receptor-Based Methods" in the MANE-VU document, *Tools and Techniques for Identifying Contributions to Regional Haze in the Northeast and Mid-Atlantic United States.* The most recent draft of Appendix B is available online at http://bronze.nescaum.org/Em/Haze-Contrib/AppendixB-04-07-05.pdf.) The results are aggregated for New England in green (Acadia National Park, Presidential Mountain Range, and Lye Brook Wilderness Area), the Mid-Atlantic in red (Washington D.C., Shenandoah National Park, and James River Face Wilderness Area), and the Southeast in blue (Great Smoky Mountains National Park and Mammoth Cave National Park).

The results shown in the figure demonstrate that in the Northeast wood smoke emissions are local, indicating that the smoke is mostly from residential wood combustion. However, in the Mid-Atlantic and Southeast Regions, the source regions for the wood smoke lie far from the monitoring sites, showing the probable influence of fires to the south.

Although source apportionment studies have not been conducted at all the Class I Areas in the MANE-VU Region, it is reasonable to conclude that throughout the Region, wood smoke is a small to moderate contributor to average fine mass. There are other general statements conclusions made in "Appendix B: Source Attribution by Receptor-Based Methods." In general, contributions are higher in rural areas than urban areas. There are also winter peaks in northern areas from residential wood burning, and occasional summer impacts from wildfires.

Although wood smoke is typically not a large contributor to $PM_{2.5}$ mass, there are exceptions, generally involving wildfires. A notable exception occurred on July 7, 2002. This event affected urban and rural sites and resulted in the largest one-day regional fine mass concentrations and visibility impacts recorded in recent years.

6. Smoke Management Programs in the MANE-VU Region

MARAMA, on behalf of MANE-VU, sent out a smoke management plan questionnaire to MANE-VU States and tribes in August 2004. The District of Columbia, Delaware, Maine, Maryland, New York, the Penobscot Indian Nation, the St. Regis Mohawk Tribe, and Vermont responded to the survey. All five states and the District of Columbia have the legal authority to allow or prohibit burning. Delaware, Maine, Maryland, and New York have a formal permitting system in place. Vermont has a SMP that applies to the nuisance of smoke. In 2004, Maine was in the development phase of a SMP being devised by the state forest service. States that do have a process for approving burns may choose to reference their program in the Regional Haze SIP as advised by the EPA.

There are incentives for States to adopt a SMP. The following statement is included in the "Interim Air Quality Policy on Wildland and Prescribed Fires," issued by the US EPA on April 23, 1998 (http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf).

> *If a certified SMP has not been implemented, EPA will not give special consideration to the high PM concentrations attributed to fires managed for resource benefits that cause or significantly contribute to: (1) violations of $PM_{2.5}$ or PM_{10} NAAQS, (2) visibility impairment in mandatory Class I Areas, or (3) failure to achieve reasonable progress toward the national visibility goal. Rather, EPA will call for adoption of the basic SMP, described in section IV of the Interim policy as part of the SIP/TIP for PM and visibility. The EPA will also notify the governor of the State or the tribal government that the area should be redesignated as nonattainment.*

The EPA also states in the Interim Policy that if State/tribal air quality managers certify in a letter to the EPA that at least a basic SMP has been adopted and implemented, "special consideration will be given under this policy to air quality data resulting from fires managed for resource benefits. When PM concentrations are attributable to wildfires that are treated under the Natural Events Policy, the EPA will "exercise its discretion, under section 107(d)(3) of the CAA, not to redesignate areas as nonattainment if the State develops and implements a plan to respond to the health impacts of natural events."

If States choose to adopt a SMP to to lessenthe future possibility of being re-designated as non-attainment, there are several elements that should be included. These elements are described in EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires," available on-line at http://www.epa.gov/ttn/oarpg/t1/memoranda/firefnl.pdf.

7. Summary

Smoke Management Programs are only required when smoke impacts from fires managed for resource benefits contribute significantly to regional haze. The results of the emissions inventory indicate that emissions from agricultural, managed, and prescribed burning are very minor source categories. Although source apportionment results show that wood smoke is a moderate contributor to visibility impairment at some Class I Areas in the MANE-VU Region, most of the wood smoke is attributable to residential wood combustion. It is unlikely that fires for agricultural or forestry management cause large impacts on visibility in any of the Class I Areas in the MANE-VU Region. On rare occasions, smoke from major fires degrades the air quality and visibility in the MANE-VU Area. However, these fires are generally unwanted wildfires that are not subject to SMPs.

Table X: Carbon Monoxide Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						12,780	6,439		0			273.3	19,492.3
Comm./Inst. Wood Comb.[2]				398.4		539.9	125.3		4117				5,180.6
Residential Wood Comb.[3]	6,5252.8	9,108.6	1,141.6	99,653.2	61,174.5	10,4461.9	63,713.5	74,311	313,179.5	74,914.9	3,666.9	31,539.4	902,117.8
Agricultural Burning[4]				1,368				1,661.8				0	3,029.8
Wildland Fires[5]	384.3	1054		0.1	1,729.9	2,018.5	1,043	4,599.1	5,120.1	2,234	175.4	22.8	18,381.2
Managed/Slash Fires[6]				0.1	42								42.1
Prescribed Fires[7]		1,430.6	0	0	457		4,084.1	4,005.1	155.8	3,396.9	79.8	0	13,609.3
Structure Fires[8]	471.8	66.7	37.1	49.6	263.7	414.2	79.2	481.7	1377.7	765.9	1.6	25.7	4,034.9
Open Burning[9]	244	998.3	0	6,318.2	70,978.5	2,418.4	1,895.7	1,70.1	8,003.6	86,714.5	294.9	11,467.8	189,504
All Fires	**66,352.9**	**12,658.2**	**1178.7**	**107,787.6**	**134,645.6**	**122,632.9**	**77,379.8**	**85,228.8**	**331,953.7**	**168,026.2**	**4,218.6**	**43,329**	**1,155,392**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Carbon Monoxide Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						12,780.0	6,439.0		0.0			273.3	19,492.3
2103008000				398.4		539.9	125.3		4,117.0				5,180.6
Indoor RWC[1]	61,903.3	8,290.4	605.6	97,150.2	56,108.0	98,315.6	61,753.6	67,230.4	293,760.9	74,914.9	2690.7	30,407.5	853,131.1
2104008070	3349.5	818.2	536.0	25,03.0	5,066.5	6,146.3	1959.9	7,080.6	19,418.6		976.2	1,131.9	48,986.8
2610000100		22.3	0.0	2,93.8	437.4	69.1	1002.5	60.3	1,290.9	1,743.1	7.3	635.2	5,561.9
2610000400		107.4	0.0	367.2	28,86.2	1,284.1	250.6	19.5	1,627.3	2,288.8	9.2	793.9	9,634.4
2610000500	244.0	739.5			66,601.1			0.0		69,750.9		9,240.5	14,6576.0
2610010000										9,81.8			981.8
2610020000										2,516.4			2,516.4
2610030000		129.1	0.0	5,657.2	1,053.8	16.3	151.0	90.3	5,085.4	9,433.5	278.4	439.7	22,334.7
2610040400			0.0			1,048.9	491.6	0.0	0.0			358.5	1,899.0
2801500000				1,368.0				1,661.8					3,029.8
2810001000	3,84.3	1,054.0		0.1	1,729.9	2,018.5	1,043.0	4,599.1	5,120.1	22,34.0	175.4	22.8	18,381.3
2810005000				0.1	42.0								42.1
2810015000		1,430.6	0.0	0.0	457.0		4,084.1	4,005.1	155.8	3,396.9	79.8		13,609.4
2810020000				0.0									0.0
2810030000	4,71.8	66.7	37.1	49.6	263.7	4,14.2	79.2	481.7	1,377.7	765.9	1.6	25.7	4,034.9
All Fires	**66,352.9**	**12,658.3**	**1,178.8**	**107,787.7**	**134,645.7**	**122,633.1**	**77,379.6**	**85,228.8**	**331,953.9**	**168,026.4**	**4,218.6**	**433,29.0**	**1,155,392.5**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Ammonia Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						0	0		0			0	0
Comm./Inst. Wood Comb.[2]				0		0	0		0				0
Residential Wood Comb.[3]	470.4	65.6	3.8	719.3	441.1	752.7	459.7	535	2,241.7	0	7	8.1	5,704.4
Agricultural Burning[4]				0				0				0	0
Wildland Fires[5]	1.7	4.7		0	0	47.7	4.7	127.4	50.3	0	0.8	0.1	237.4
Managed/Slash Fires[6]				0	0								0
Prescribed Fires[7]		6.4	0	0.5	0		18.4	6.9	0	15.3	0.4	23	70.9
Structure Fires[8]	0	0	0	0	0	0	0	0	0	0	0	0	0
Open Burning[9]	0	1.3	0	0	30.9	21.8	11.3	0	29.1	40.2	0	17.4	152
All Fires	**472.1**	**78**	**3.8**	**719.8**	**472**	**822.2**	**494.1**	**669.3**	**2,321.1**	**55.5**	**8.2**	**48.6**	**6,164.7**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Ammonia Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000													
2013008000													
Indoor RWC[1]	446.5	59.8	0.0	701.5	405.0	708.9	445.7	484.5	2,103.3	0.0	0.0	0.0	5,355.2
2104008070	23.9	5.8	3.8	17.8	36.1	43.8	14.0	50.5	138.4		7.0	8.1	349.1
2610000100		0.3	0.0		4.9	0.8	11.3		14.5	19.6		7.1	58.5
2610000400		1.0	0.0		26.0	11.6			14.6	20.6		7.1	80.9
2610000500													
2610010000													
2610020000													
2610030000													
2610040400			0.0			9.4			0.0			3.2	12.7
2801500000.													
2810001000	1.7	4.7				47.7	4.7	127.4	50.3		0.8	0.1	237.4
2810005000													
2810015000		6.4	0.0	0.5			18.4	6.9		15.3	0.4	23.0	70.8
2810020000													
2810030000													
All Fires	**472.1**	**78.0**	**3.8**	**719.8**	**472.0**	**822.2**	**494.0**	**669.3**	**2,321.1**	**55.5**	**8.1**	**48.6**	**6,164.6**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Nitrogen Oxides Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						4,686.1	5,258.6		0			30.2	9,974.9
Comm./Inst. Wood Comb.[2]				1,206.4		197.9	102.3		148.3				1,654.9
Residential Wood Comb.[3]	821.3	120.2	13.2	1,265.1	751.1	1,331.8	815.1	943	3647	929.7	44.3	396.4	11,078.2
Agricultural Burning[4]				54				0.2				0	54.2
Wildland Fires[5]	8.2	22.6		0.4	49.4	57.2	22.4	131.4	109.8	63.8	3.8	0.5	469.5
Managed/Slash Fires[6]				0	1.2								1.2
Prescribed Fires[7]		30.7	0	0	0		87.6	0	3.3	72.9	1.7	0	196.2
Structure Fires[8]	11	1.6	0.9	1.2	6.2	9.7	1.8	11.2	32.1	17.9	68.3	0.6	162.5
Open Burning[9]	6.6	36	0	399.3	2,402	88.4	83.7	10.4	488.2	3,154	19.7	380.8	7,069.1
All Fires	**847.1**	**211.1**	**14.1**	**2,926.4**	**3,209.9**	**6,371.1**	**6,371.5**	**1,096.2**	**4,428.7**	**4,238.3**	**137.8**	**808.5**	**30,660.7**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Nitrogen Oxides Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						4,686.1	5,258.6		0.0			30.2	9,974.8
2103008000				1,206.4		197.9	102.3		148.3				1,655.0
Indoor RWC[1]	786.8	111.8	7.7	1,239.3	699.0	1,268.5	794.9	870.1	3,447.1	929.7	34.3	384.7	10,573.9
2104008070	34.5	8.4	5.5	25.8	52.1	63.3	20.2	72.9	199.9		10.0	11.7	504.2
2610000100		1.2	0.0		24.2	3.8	55.5	3.3	71.5	96.5		35.2	291.2
2610000400		3.8	0.0		103.1	45.9		0.7	58.1	81.7		28.4	321.7
2610000500	6.6	21.9			2,200.4			0.0		2,063.6		273.4	4,565.9
2610010000										69.3			69.3
2610020000										177.6			177.6
2610030000		9.1	0.0	399.3	74.3	1.2	10.6	6.4	358.6	665.3	19.7	31.0	1,575.5
2610040400			0.0			37.5	17.6	0.0	0.0			12.8	67.8
2801500000				54.0				0.2					54.2
2810001000	8.2	22.6		0.4	49.4	57.2	22.4	131.4	109.8	63.8	3.8	0.5	469.6
2810005000				0.0	1.2								1.2
2810015000		30.7	0.0	0.0	0.0		87.6	0.0	3.3	72.9	1.7		196.2
2810020000				0.0									0.0
2810030000	11.0	1.6	0.9	1.2	6.2	9.7	1.9	11.2	32.1	17.9	68.4	0.6	162.5
All Fires	**847.1**	**211.1**	**14.1**	**2,926.4**	**3,210.0**	**6,370.9**	**6,371.5**	**1,096.2**	**4,428.8**	**4,238.3**	**137.8**	**808.4**	**30,660.6**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: PM$_{10}$ Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						11,012.1	4,045.9		0			30.3	15,088.3
Comm./Inst. Wood Comb.[2]				0		465.3	78.7		115				659
Residential Wood Comb.[3]	8,520.7	1,227.9	157.9	12,569.5	8,194.3	13,689.3	8,019.3	9,900.7	41,980	10,285.6	508.9	4,093.4	11,9147.5
Agricultural Burning[4]				2.4				203.6				2.4	208.4
Wildland Fires[5]	37.4	102.6		0	210.1	244.9	101.4	985.5	497.8	207.4	17.1	2.2	2,406.4
Managed/Slash Fires[6]				0	5.1								5.1
Prescribed Fires[7]		139.2	0	0	82		397.1	389.9	15.2	330.3	7.8	0	1,361.5
Structure Fires[8]	84.9	12	6.7	8.9	47.5	414.2	14.3	86.7	248	0	12.1	4.6	939.9
Open Burning[9]	30.8	122.3	0	2,673.4	8,205.6	345.9	329.8	34.3	1,599.9	9,753.5	128.1	1,373.5	24,597.1
All Fires	**8,673.8**	**1,604**	**164.6**	**15,254.2**	**16,744.6**	**26171.7**	**12,986.5**	**11,600.7**	**44,455.9**	**20,576.8**	**674**	**5,506.4**	**164,413.2**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: PM$_{10}$ Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						11,012.1	4,045.9		0.0			30.3	15,088.2
2103008000						465.3	78.7		115.0				659.1
Indoor RWC[1]	8,061.9	1,115.8	84.5	12,226.7	7,500.3	12,847.4	7,750.8	8,930.8	39,320.1	10,285.6	375.2	3,938.4	11,2437.5
2104008070	458.8	112.1	73.4	342.8	694.0	841.9	268.5	969.9	2,659.9		133.7	155.0	6,710.0
2610000100		4.4	0.0	99.7	85.9	13.6	196.9	11.8	253.6	342.4	2.5	124.8	1,135.5
2610000400		15.1	0.0	44.6	406.8	180.9	30.4	2.7	229.3	322.6	1.1	111.9	1,345.5
2610000500	30.8	74.4			7,481.4			0.0		7,016.4		929.5	15,532.4
2610010000													
2610020000													
2610030000		28.4	0.0	2,529.1	231.5	3.6	33.2	19.8	1,117.0	2,072.1	124.5	156.8	6,316.0
2610040400			0.0			147.8	69.3	0.0	0.0			50.5	267.6
2801500000				2.4				203.6				2.4	208.3
2810001000	37.4	102.6		0.0	210.1	244.9	101.4	985.5	497.8	207.4	17.1	2.2	2,406.4
2810005000				0.0	5.1								5.1
2810015000		139.2	0.0	0.0	82.0		397.1	389.9	15.2	330.3	7.8		1,361.5
2810020000				0.0									0.0
2810030000	84.9	12.0	6.7	8.9	47.5	414.2	14.3	86.7	248.0		12.1	4.6	939.9
All Fires	**8,673.8**	**1,603.9**	**164.6**	**15,254.3**	**16,744.4**	**26,171.7**	**12,986.4**	**11,600.9**	**44,455.9**	**2,0576.8**	**673.9**	**5,506.5**	**16,4413.1**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: $PM_{2.5}$ Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						9,521.1	3,509.3		0			30.3	13,060.7
Comm./Inst. Wood Comb.[2]				0		402.3	68.3		96.6				567.2
Residential Wood Comb.[3]	8,520.7	1,227.9	157.9	12,569.5	8,194.3	13,689.3	8,019.3	9,900.7	36,702.8	10,285.6	508.9	3,817.7	11,3594.6
Agricultural Burning[4]				2.1				203.6				2.1	207.8
Wildland Fires[5]	32	87.9		0	210.1	244.9	87	887	427	186.7	14.6	1.9	2179.1
Managed/Slash Fires[6]				0	5.1								5.1
Prescribed Fires[7]		119	0	0	82		340.6	334.2	13	283.3	6.7	0	1,178.8
Structure Fires[8]	77.3	10.9	6.1	8.1	43.2	414.2	13	86.7	225.7	0	11	4.2	900.4
Open Burning[9]	30.8	116.5	0	2,460.4	8,092.9	270.4	311.1	32.1	1,453.4	9,505.1	117.6	1,323.1	23,713.4
All Fires	**8,660.8**	**1,562.2**	**164**	**15,040.1**	**16,627.6**	**24,542.2**	**12,348.6**	**11,444.3**	**38,918.5**	**20,260.7**	**658.8**	**5,179.3**	**155,407.1**

[1] SCC 2102008000; [2] SCC 2103008000; [3] SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4] SCC 2801500000; [5] SCC 2810001000; [6] SCC 2810005000; [7] SCC 2810015000 and SCC 2810020000; [8] SCC 2810030000; [9] SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: $PM_{2.5}$ Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						9,521.1	3,509.3		0.0			30.3	13,060.7
2103008000						402.3	68.3		96.6				567.1
Indoor RWC[1]	8,061.9	1,115.8	84.5	12,226.7	7,500.3	12,847.4	7,750.8	8,930.8	34,468.5	10,285.6	375.2	3,662.7	107,310.2
2104008070	458.8	112.1	73.4	342.8	694.0	841.9	268.5	969.9	2,234.3		133.7	155.0	6,284.4
2610000100		4.4	0.0	99.7	85.9	13.6	196.9	11.8	253.6	342.4	2.5	124.8	1,135.5
2610000400		11.7	0.0	44.6	313.6	139.5	30.4	2.1	176.8	248.7	1.1	86.3	1,054.7
2610000500	30.8	74.4			7,481.4			0.0		7,016.4		929.5	15,532.4
2610010000													
2610020000													
2610030000		26.0	0.0	2,316.1	212.0	3.3	30.4	18.2	1,023.0	1,897.6	114.0	143.6	5,784.1
2610040400			0.0			114.0	53.4	0.0	0.0			38.9	206.3
2801500000				2.2				203.6				2.1	207.9
2810001000	32.0	87.9		0.0	210.1	244.9	87.0	887.0	427.0	186.7	14.6	1.9	2,179.1
2810005000				0.0	5.1								5.1
2810015000		119.0	0.0	0.0	82.0		340.6	334.2	13.0	283.3	6.7		1,178.7
2810020000				0.0									0.0
2810030000	77.3	10.9	6.1	8.1	43.2	414.2	13.0	86.7	225.7		11.0	4.2	900.4
All Fires	**8,660.8**	**1,562.1**	**164.0**	**15,040.3**	**16,627.5**	**24,542.1**	**12,348.5**	**11,444.3**	**38,918.3**	**20,260.6**	**658.8**	**5,179.4**	**155,406.7**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: Sulfur Dioxide Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						532.5	268.3		0			1,803.4	2,604.2
Comm./Inst. Wood Comb.[2]				0		22.4	5.2		7.6				35.2
Residential Wood Comb.[3]	120.1	16.1	1.9	184	107	193.5	119	132.4	614.9	142	6.7	58.2	1,695.8
Agricultural Burning[4]				0				0.2				0	0.2
Wildland Fires[5]	2.3	6.2		0	0	0	6.1	0	0	2.4	1	0	18
Managed/Slash Fires[6]				0	0								0
Prescribed Fires[7]		8.4	0	1.6	0		24	0	0.9	20	0.5	0	55.4
Structure Fires[8]	0	0	0	0	0	532.5	0	0	0	0	0	0	532.5
Open Burning[9]	0	3	0	66.6	49.6	28.2	14.4	1.7	88.1	150.1	3.3	23.2	428.2
All Fires	**122.4**	**33.7**	**1.9**	**252.2**	**156.6**	**1,309.1**	**437**	**134.3**	**711.5**	**314.5**	**11.5**	**1,884.8**	**5,369.5**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: Sulfur Dioxide Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						532.5	268.3		0.0			1,803.4	2,604.2
2103008000						22.4	5.2		7.6				35.2
Indoor RWC[1]	114.8	14.8	1.1	180.0	99.0	183.8	115.9	121.2	584.2	142.0	5.2	56.4	1,618.4
2104008070	5.3	1.3	0.8	4.0	8.0	9.7	3.1	11.2	30.8		1.5	1.8	77.6
2610000100		0.2	0.0		3.0	0.5	6.8	0.4	8.8	11.8		4.3	35.7
2610000400		1.3	0.0		34.2	15.1		0.2	19.3	27.1		9.4	106.7
2610000500					0.0								0.0
2610010000													
2610020000													
2610030000		1.5	0.0	66.6	12.4	0.2	1.8	1.1	60.0	111.2	3.3	5.2	263.2
2610040400			0.0			12.4	5.8	0.0	0.0			4.3	22.5
2801500000								0.2					0.2
2810001000	2.3	6.2				0.0	6.1	0.0		2.4	1.0		18.0
2810002000													
2810003000								0.0					0.0
2810015000		8.4	0.0	1.6			24.0	0.0	0.9	20.0	0.5		55.4
2810030000						532.5		0.0					532.5
All Fires	**122.4**	**33.6**	**1.9**	**252.1**	**156.6**	**1,309.2**	**437.1**	**134.3**	**711.5**	**314.6**	**11.5**	**1,884.7**	**5,369.5**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

Table X: VOC Wood Smoke Emissions (Tons/Year) by Source (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

Source Category	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
Industrial Wood Comb.[1]						362.1	182.4		0			28.1	572.6
Comm./Inst. Wood Comb.[2]				27.3		15.3	3.6		3.9				50.1
Residential Wood Comb.[3]	41,067.8	5,952.1	732.9	5,9815.6	39,433.8	66,217.4	38,652	49,989.2	226,181.7	25,537.3	1,981.9	10,970	566,531.7
Agricultural Burning[4]				128.4				235				0	363.4
Wildland Fires[5]	18.1	49.6		0	92.9	345.4	49.1	778.6	240.9	383	8.3	1.1	1,967
Managed/Slash Fires[6]				0	5.7								5.7
Prescribed Fires[7]		67.4	0	0	70.3		192.2	275.7	7.3	159.9	3.8	0	776.6
Structure Fires[8]	86.5	12.2	6.8	9.1	48.3	76	14.5	88.3	252.6	140.4	12.5	4.7	751.9
Open Burning[9]	20	77.4	0	2,119.9	5,124.5	334.7	358.8	22.2	795.1	7,235.2	101.3	985.1	17,174.2
All Fires	**41,192.4**	**6,158.7**	**739.7**	**62,100.3**	**44,775.5**	**67,350.9**	**39,452.6**	**51,389**	**227,481.5**	**33,455.8**	**2,107.8**	**11,989**	**588,193.2**

[1]SCC 2102008000; [2]SCC 2103008000; [3]SCC 2104008000 (or SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, and SCC 2104008052) and SCC 2104008070; [4]SCC 2801500000; [5]SCC 2810001000; [6]SCC 2810005000; [7]SCC 2810015000 and SCC 2810020000; [8]SCC 2810030000; [9]SCC 2610000100, SCC 2610000400, SCC 2610000500, SCC 2610010000, SCC 2610020000, SCC 2610030000, and SCC 2610040400

Table X: VOC Wood Smoke Emissions (Tons/Year) by SCC (Source: 2002 MANE-VU Modeling Inventory, Version 3.0 with updated NY data).

SCC	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	TOTAL
2102008000						362.1	182.4		0.0			28.1	572.7
2103008000				27.3		15.3	3.6		3.9				50.1
Indoor RWC[1]	38,031.2	5,210.4	246.9	57,546.5	34,840.6	60,645.3	36,875.2	43,570.1	208,577.3	25,537.3	1,096.9	9,943.8	522,121.5
2104008070	3,036.6	741.7	486.0	2,269.1	4,593.2	5,572.1	1,776.8	6,419.1	17,604.4		885.0	1,026.2	44,410.1
2610000100		5.6	0.0	73.4	109.3	17.3	250.6	15.1	322.7	435.8	1.8	158.8	1,390.5
2610000400		14.6	0.0	49.8	391.7	174.2	34.0	2.6	220.9	310.6	1.2	107.7	1,307.5
2610000500	20.0	50.8			4,571.4			0.0		4,787.6		634.3	10,064.1
2610010000										346.5			346.5
2610020000										888.1			888.1
2610030000		6.4	0.0	1,996.7	52.1	0.8	7.5	4.5	251.5	466.6	98.3	35.6	2,919.9
2610040400			0.0			142.4	66.7	0.0	0.0			48.7	257.7
2801500000				128.4				235.0					363.4
2810001000	18.1	49.6		0.0	92.9	345.4	49.1	778.6	240.9	383.0	8.3	1.1	1,966.9
2810005000				0.0	5.7								5.7
2810015000		67.4	0.0	0.0	70.3		192.2	275.7	7.3	159.9	3.8		776.6
2810020000				0.0									0.0
2810030000	86.5	12.2	6.8	9.1	48.3	76.0	14.5	88.3	252.6	140.4	12.5	4.7	752.0
All Fires	**41,192.3**	**6,158.6**	**739.7**	**62,100.4**	**44,775.6**	**67,350.9**	**39,452.6**	**51,389.0**	**227,481.6**	**33,455.8**	**2,107.8**	**11,989.0**	**588,193.2**

[1] For indoor residential wood combustion, CT, DE, ME, MD, MA, and NH provided data for total woodstoves and fireplaces (SCC 2104008000). DC, NJ, NY, PA, RI, and VT instead reported data for separate woodstove and fireplace categories (SCC 2104008001, SCC 2104008002, SCC 2104008003, SCC 2104008004, SCC 2104008010, SCC 2104008030, SCC2104008050, SCC 2104008052). The separate category data were added together to get a total woodstoves and fireplaces value for these states.

ATTACHMENT W

MANE-VU Five-Factor Analysis of BART-Eligible Sources

Five-Factor Analysis of BART-Eligible Sources

Survey of Options for Conducting BART Determinations

Prepared by
NESCAUM
for the
Mid-Atlantic/Northeast Visibility Union (MANE-VU) Regional Planning Organization

June 1, 2007

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FIVE-FACTOR ANALYISIS OF BART-ELIGIBLE SOURCES

Survey of Options for Conducting BART Determinations

Project Manager

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Acknowledgements

NESCAUM acknowledges the support of its member agencies and the staff time that they dedicated in providing survey information on the types and level of control available for various source categories subject to the BART requirements of the Regional Haze Rule. Their insight has allowed NESCAUM to create what it hopes will be a valuable guide for all members of MANE-VU as they proceed to conduct source-specific BART determinations. NESCAUM also acknowledges the funding for this work through U.S. EPA agreement number XA-97318101-0 to the Ozone Transport Commission in support of the MANE-VU Regional Planning Organization. NESCAUM is solely responsible for the content of this report and any errors it may contain.

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Executive Summary

The 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)] requires certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART). These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act.

States are required to undertake three key steps to comply with the BART requirements of the Regional Haze Rule. These steps include:

- Determining if a source is BART-eligible;
- Determining if a source reasonably causes or contributes to visibility impairment in any Class I area (subject to BART);
- Determining if additional controls or emission limits are necessary (BART determination).

This report is intended to summarize one approach to satisfy the BART requirements of the Regional Haze Rule that member states may consider. We also review BART-eligible sources in the MANE-VU region and provide – on a regional basis – an analysis of the general applicability of the five statutory factors that states must consider in determining BART controls for various source categories subject to BART. This analysis will allow MANE-VU states to place their source-specific BART determinations into the regional context of similar sources within MANE-VU. This review includes an examination of individual units' impacts on visibility at Class I areas based on CALPUFF modeling and an evaluation of existing or potential controls and feasibility of these controls relative to the statutory factors identified in the BART rule.

Ultimately, the strength of the MANE-VU BART program, as determined by individual state control decisions and informed by this analysis, will demonstrate MANE-VU's resolve to tackle visibility and related air quality problems in its region. As MANE-VU enters into consultations with other regional planning organizations (RPOs), its willingness to seek reasonable emission reductions within its own region will help set expectations for the other RPOs, and the BART program represents a cornerstone of this process.

1. INTRODUCTION

The 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)] requires certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART).[1] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from new source performance standards (NSPS) requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns, and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation or come into existence in the 15 year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments, which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically (i.e., through reasonably attributable visibility impairment requirements in the 1980 haze regulations). In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible state initiatives (e.g. market-based approaches), provided such alternatives can be shown to achieve greater progress toward visibility objectives than the source by source BART approach.

1.1. The BART Rule

In June 2001, EPA released proposed guidelines on BART. This guidance outlined the method for determining if a facility has a BART-elgible source, if a source is subject to BART provisions, and methods for conducting a BART control review for such sources.

In 2002, industry groups challenged the method EPA outlined in the Regional Haze Rule to determine the degree of visibility improvement resulting from application of BART controls. Under EPA's interpretation of the statute, a state would deem sources subject to BART if they emitted into a geographic area or region from which pollutants are likely transported downwind into a protected area. In May 2002, the D.C. Circuit Court of Appeals agreed with industry petitioners that this interpretation impermissibly constrained the authority of any state that wanted to provide an exemption mechanism from BART requirements. The Court vacated those portions of the Regional Haze Rule dealing with BART.

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

In June 2005, EPA released the final BART guidelines that also addressed the remanded portions of the Regional Haze Rule dealing with BART. Under the final rule, the BART program requires states to develop an inventory of sources within each state or tribal jurisdiction that could be subject to control. Specifically, the rule:

- Outlined methods to determine if a source is "reasonably anticipated to cause or contribute to haze;"
- Defined the methodology for conducting a BART control analysis;
- Provided presumptive control limits for electricity generating units (EGUs) larger than 750 Megawatts;
- Provided a justification for the use of the Clean Air Interstate Rule (CAIR) as BART for CAIR state EGUs.

Beyond the specific elements listed above, EPA provided the states with a great degree of flexibility in how they choose to implement the BART program. The following section summarizes the core requirements for state compliance with BART regulations.

1.2. Overview of State BART Requirements

As finally promulgated, States are required to undertake three key steps to comply with the BART requirements of the Regional Haze Rule. These steps include:

- Determining if a source is BART-eligible;
- Determining if a source reasonably causes or contributes to visibility impairment in any Class I area (subject to BART);
- Determining if additional controls or emission limits are necessary (BART determination).

As stated earlier, eligibility is limited to sources in one of 26 source categories that have units installed and operating between 1962 and 1977 with the potential to emit more than 250 tons per year of a visibility impairing pollutant. Once a source is found to be "eligible" for the BART program, states must determine if that source is "subject to BART," that is, if it causes haze or contributes to the formation of haze at any Class I area. EPA's 2005 rule outlines three options to determine if a source is subject to BART. These options include:

- ***Individual source assessment (Exemption Modeling)*** – This assessment uses CALPUFF or other EPA approved modeling methods. Results of modeling would be compared to natural background conditions. EPA defined "cause" as an impact of 1.0 deciview or more and "contribute" as an impact of 0.5 deciview or more.[2] The rule, however, gave states discretion to set lower thresholds for contribution.

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[2] Impacts are based on the difference in deciviews (delta deciview) calculated between the best twenty percent natural visibility conditions (states have the option to use annual average conditions as an alternative) at a Class I site with and without individual source contributions included.

- ***Cumulative assessment of all BART "eligible sources"*** – Under this method, a state can choose to find that all eligible sources within a geographic area or region are subject to BART. This method could also be used to analyze an area's contribution to visibility impairment and demonstrate that *no* sources are subject, based on cumulative modeling.
- ***Assessment based on model plants*** – This method provides a mechanism to exempt sources with common characteristics that are found not to impair visibility at Class I areas.

Once a source has been identified as BART-eligible and "subject" to BART, it must conduct an engineering review to determine if the installation of new control requirements is appropriate.[3] This review takes into consideration five factors:

- Cost of controls
- Energy and non-air quality environmental impacts
- Existing controls at source
- Remaining useful life of source
- Visibility improvement reasonably expected from application of the controls.

1.3. Overview of Report

This report is intended to summarize an approach to satisfy the BART requirements of the Regional Haze Rule based on the "cumulative assessment of contribution" option for determining if eligible sources are subject to BART. We also review BART-eligible sources in the MANE-VU region and provide – on a regional basis – an analysis of the general applicability of the five factors for various source categories subject to BART. This analysis should not be viewed as preventing states from exercising their flexibility in structuring their own approach to BART or in applying the five factors to that approach. Rather, this analysis will allow MANE-VU states to place their source-specific BART determinations into the regional context of similar sources within MANE-VU. This review includes an examination of individual units' impacts on visibility at Class I areas, based on CALPUFF modeling and an evaluation of existing or potential controls and feasibility of these controls relative to the statutory factors identified in the BART rule[4].

To that end, Section 2 of this report first develops a list of all BART-eligible sources in the MANE-VU region. Section 3 provides an overview of the region's approach to determining BART eligibility. Finally, Section 4 presents observations on the regional and sectoral differences among control options and the applicability of the five-factor analysis.

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[3] A possible exception to this requirement would exist in the case where a state has adopted a "better than BART" alternative program that would take the place of a source-specific BART determination. The RPO is not aware of any MANE-VU states that are adopting such programs at this time.

[4] Throughout this report we refer to the collection of sources at a stationary facility potentially subject to BART as a "BART-eligible source." Individual emitting units at these BART-eligible sources will be referred to as "units" when emissions are modeled and descriptions of possible control strategies are offered.

2. DETERMINING BART-ELIGIBLE SOURCES

To assist MANE-VU states and tribes with BART implementation efforts, MANE-VU developed a list of BART-eligible sources in the region (NESCAUM, 2001; NESCAUM, 2003). Since then, the preliminary list developed in these documents was refined through consultation with state permitting staff to verify completeness and accuracy of the list. Emissions of SO_2, NO_X, and PM_{10} as well as stack information were compiled through either consultation with state permitting staff or the 2002 MANE-VU emissions inventory. The final list of sources (as well as associated 2002 emissions and stack parameters) was developed in consultation with state staffs (see Appendix A for a complete list of BART-eligible sources and units in the MANE-VU region).

3. MANE-VU APPROACH TO "SUBJECT TO BART"

Based on the MANE-VU contribution assessment (NESCAUM, 2006b), every MANE-VU state with BART-eligible sources contributes to visibility impairment at a Class I area to a significant degree. Therefore, MANE-VU staff continues to support the policy decision made by the MANE-VU Board in June 2004, that ***if a source is eligible for BART, it is subject to BART***. (i.e., no exemption test will be used). The reasons why MANE-VU has chosen to pursue this option for demonstrating its sources are reasonably anticipated to cause or contribute to visibility impairment at Class I areas are threefold: (1) the BART sources represent an opportunity to achieve greater reasonable progress, (2) additional public health and welfare benefits will accrue from resulting decreases in fine particulate matter, and (3) to demonstrate its commitment to federal land managers (FLMs) and other RPOs as it seeks emissions reductions wherever it is reasonable to do so.

This recommendation is not equivalent, however, to the statement that every BART-eligible source must install controls. The approach presented for MANE-VU state consideration – starting with this document and continuing with their own source specific analyses – requires the consideration of each of the five factors required by statute before determining whether or not controls are warranted.

4. REGIONAL FIVE FACTOR ANALYSIS

4.1. The Degree of Visibility Improvement That May Reasonably be Anticipated from the Use of BART

BART emission limits must be determined subject to an evaluation of the five statutory factors. These factors include:

(a) the costs of compliance,
(b) the energy and non-air quality environmental impacts of compliance,
(c) any existing pollution control technology in use at the source,
(d) the remaining useful life of the source, and

(e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

To begin its regional analysis of these factors, MANE-VU staff first considered the degree of visibility improvement that could result from the installation of BART controls. This is slightly different than the statutory language and is meant to reflect our first-order approach to estimating the maximum visibility benefit that could be achieved by eliminating all emissions from the source. While this is not a realistic approach to fully satisfying the intent of factor (e) above, it does provide the states a useful metric for determining which sources are unlikely to warrant BART controls based on consideration of this factor.

This analysis was achieved by first modeling 2002 emissions of SO_2, NO_X, and PM_{10} from all BART-eligible units in the region.[5] A total of 136 BART-eligible sources were identified in the MANE-VU region and modeled on the two CALPUFF platforms. Table 4-1 displays the types and numbers of sources modeled in the region.

Table 4-1. Types of BART-eligible sources modeled in the region

Source Type	Number of Sources	Number of Units/MM5*	Number of Units/NWS
Chemical Manufacturer	12	48	107
Chemical Plant	1	4	18
Coal Cleaning	1	1	1
EGU	59	139	296
Glass Fiber	3	14	33
Incinerator	1	2	2
Industrial Boilers	2	6	8
Lime Plant	2	4	14
Metal Production	13	64	140
Mineral Products	1	4	13
Paper and Pulp	14	39	63
Petroleum Storage	4	6	10
Portland Cement	13	49	228
Refinery	9	70	497
Total	**136**	**455**	**1449**

* Units with very small emissions were grouped together and modeled as one stack for the MM5-based CALPUFF runs.

The two CALPUFF modeling platforms are described in greater detail elsewhere (NESCAUM, 2006b) and are driven by two respective meteorological datasets: 1) a wind field based on National Weather Service (NWS) observations and 2) a wind field based on output from the MM5 meteorological model (MM5, 2006). Environmental Resources Management (ERM) developed CALMET-processed meteorology on a large domain (extending from Oklahoma City, OK up to Prince Edward Island, Canada). The CALMET meteorology was processed directly from the MM5 model output developed

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[5] Emissions information was gathered from the MANE-VU 2002 Version 2 (Base A) emissions inventory. Since then, the MANE-VU 2002 Version 3 (Base B) emissions inventory has been developed which includes several changes made by the OTC modeling committee.

on a 12-km horizontal grid by the University of Maryland for the OTC modeling committee and MANE-VU. The Vermont Department of Environmental Conservation (VT DEC) developed CALMET meteorology (for the identical domain) driven by the NWS's surface observation network, rawinsonde network, and supplemented by the Airport Surface Observation System (ASOS) network. This observation-based dataset provides an alternative to the gridded wind fields generated by the diagnostic model MM5.

Modeling results from both NWS and MM5 platforms have been made available to the states involved in this process. Results include each BART-eligible unit's maximum 24-hr, 8th highest 24-hr, and annual average impact at the Class I area most heavily impacted, as well as the total impact from all BART sources on each Class I area. These visibility impacts were modeled relative to 20 percent best, 20 percent worst, and annual average natural background conditions. For the purposes of this analysis, we examined the 24-hr maximum visibility impact relative to the 20 percent best days. On July 19, 2006, EPA provided clarification to guidance that states may use either estimates of 20 percent best or annual average natural background visibility conditions as the basis for calculating the deciview difference that individual sources would contribute for BART exemption modeling purposes. MANE-VU has opted to use the best conditions estimates for their consideration of the "degree of visibility improvement" modeling because it is more protective to the region.

Given that no modeling of 2018 "post-BART" emission levels has been conducted yet, the 2002 modeling, in essence, provides MANE-VU with an estimate of the maximum improvement in visibility that could result from installation of BART controls at Class I areas in the region (i.e., if the source was zeroed out). In virtually all instances, the installation of BART controls would result in less visibility improvement than what is represented by a source's 2002 impact, but this does provide a consistent means of identifying those sources whose emissions represent a more significant contribution to visibility impairment than others.

In July of 2004, MANE-VU submitted comments to EPA that included visibility impact analysis of a representative sample of EGUs across the country. Based on that representative sample, MANE-VU determined that the value of the maximum 24-hour impact relative to natural conditions that would include 98 percent of the cumulative visibility impact on MANE-VU sites was likely between 0.1 and 0.2 dv. However, this dataset was limited in that it only explored the relationship of EGUs and did not provide an indication of how the total frequency impact might change with numerous smaller, non-EGU, BART-eligible sources. With this new CALPUFF modeling data, we were able to repeat this analysis for the dataset that included all BART-eligible units in the region. This analysis remains limited that in that it includes only MANE-VU sources. It is likely that the additional sources from VISTAS and MWRPO would add to the total visibility impairment experienced at MANE-VU class I areas and, to some extent, to the top 98 percent of the visibility impacts. Without knowing the exact contribution of extra-regional BART sources to impairment at our Class I sites, it is impossible to determine the cumulative 98th percentile frequency precisely.

Notwithstanding this limitation, the results of this new analysis showed that 98 percent of the cumulative frequency visibility impact from all MANE-VU BART-eligible sources corresponds to a maximum 24-hr impact of 0.22 dv from the NWS-driven data and 0.29 dv from the MM5 data. We therefore concluded that a range of 0.2 to 0.3 dv would represent a "significant" impact at MANE-VU Class I areas on an average basis. Given the analysis and the limitation due to exclusion of sources outside of MANE-VU, we decided to place increased weight on sources with an individual visibility impact greater than 0.1 dv for this 1st order regional 5-factor analysis. This threshold is overly inclusive relative to exemption processes being conducted by other RPOs, but still provides MANE-VU states flexibility in choosing the weight to be given to the first of the five factors considered (i.e., the degree of visibility improvement that could result from BART).

As an additional demonstration that sources whose impact were below the 0.1 dv level were too small to warrant BART controls, the entire MANE-VU population of these units was modeled together to examine their cumulative impacts on each Class I site. The result of this simulation showed that the maximum 24-hr impact at any Class I area of *all* modeled sources with individual impacts below 0.1 dv was only a 0.35 dv change relative to the estimated best days natural conditions at Acadia National Park. This value is below the 0.5 dv impact recommended by EPA for exemption modeling and we can be fairly certain that sources below the 0.1 dv level have very small individual impacts on visibility at Class I areas.

Among the sources with a greater than 0.1 dv total impact at any Class I area were 29 EGUs with 95 BART-eligible units that are located in states subject to CAIR. These CAIR-eligible EGU units may use the CAIR program to satisfy BART for SO_2 and in most cases NO_X BART. We did not consider these sources further with the exception of the three EGU sources (eight units) that had greater than 0.1 dv contribution for PM alone. These three EGU sources, along with 14 additional EGU sources in states that are not subject to CAIR (17 EGUs total), and 36 additional non-EGU sources with visibility impacts that may warrant BART controls are listed in Table 4-2 by type.

Table 4-2. Types of sources in MANE-VU region with greater than 0.1 dv impact at any Class I area (non year-round CAIR states).

Source Type	Number of Sources	Number of Units/MM5*
Chemical Manufacturer	1	3
Coal Cleaning	1	1
EGU	17	30
Glass Fiber	1	6
Incinerator	1	2
Metal Production	2	7
Paper and Pulp	12	30
Portland Cement	12	25
Refinery	5	37
Total	53	142

*Only MM5 Data were used for this analysis.

4.2. Cost and Availability of Controls and Controls Already in Place

The second and third steps of the MANE-VU five-factor analysis involved evaluating current controls at sources and costs of additional controls at these sources – factors (a) and (c) above. To address these factors, the list of these 53 highest impacting sources, including all the BART-eligible units at these sources (142 units), was sent out to state permitting staff for feedback on possible controls recommendations for these types of units and cost information for typical installation of these controls. Several states informed us that some of the eligible sources are subject to future controls under existing state regulations that will achieve "BART-like" levels of control. In these cases, we have listed the control level where applicable, or designated the control as "Currently Controlled" if the controls are already in place. Other states are considering a cost threshold to determine whether controls are feasible. If potential additional controls are above any known cost thresholds, then it is likely that a state would not feel that additional controls beyond those currently in place are warranted and we have therefore designated such units as "No Further Controls Warranted." In situations where we did not have sufficient information to assess current or potential future controls, the unit has been designated as "No Known Further Controls." In cases where other control programs such will satisfy BART, the control program is listed. Finally, we have listed the control technology as "No Known Further Controls" for BART-eligible sources where no information was available on possible control options.

NESCAUM compiled the available survey results provided by state staffs on expected or potential controls on these units and projected 2018 emissions from these units. Summaries of these results are found in Table 4-3 to Table 4-5. Cost information for various control options was obtained from a variety of sources including individual states, previous NESCAUM reports (NESCAUM, 2005), and other RPO analyses. Cost estimates from NESCAUM (2005) as well as the low, medium, and high cost designations described in the Tables 4.3-4.5 are summarized in Appendix B. Obviously, more detailed analysis of the cost of various control options will have to be conducted at the source-specific level by the states as they conduct source-specific BART determinations.

Table 4-3. Possible range of SO_2 controls and costs based on survey of state staff

Type of Source	Number of Sources	Control Strategies	Number of Emission Units Control Strategy May Apply	Total 2002 SO_2 Emissions	Total Estimated Decrease in SO_2 (tons/yr)	Estimated Cost ($/Ton SO2)	Notes
Chemical Manufacturer	3	SO2 Scrubber	1	24000	9600	400-8000	Mid Range (1)
		Currently Controlled	2	80	NA	0	
Glass Fiber	6	Currently Controlled	6	17	0	0	
Coal Cleaning	1	No Known Further Controls	1	68	0	0	
EGU/Coal	5	Dry Scrubber	4	58000	52600	200-500	Mid Range, assume 90% scrubber efficiency
		0.33 lb/MMBtu	1	4000	1200	NA	
EGU/Oil (Resid and Dist)	17	0.3% fuel sulfur limit	3	1400	340	0	Switch to 0.3% has already occurred for 3 boilers.
		0.56 lb/MMBtu	1	85	NA	NA	
		2.0 % Fuel Sulfur Limit	1	600	300	NA	
		1.5% Fuel Sulfur Limit	1	5200	3900	NA	
		0.33 lb/MMBtu	1	4000	3100	NA	
		3.0 lb/MWh	5	31000	NA	NA	
		1.1-1.2 lb/MMBtu	2	480	NA	NA	
		Currently Controlled	3	1200	0	0	
Incinerator	2	Currently Controlled	2	84	0	0	
Metal Production	7	No Further Controls Warranted	5	2200	0	0	
		Increased efficiency of the facility's wet scrubber	2	3000	300	Limited Cost	Low Range
Paper and Pulp	30	FGD (SO_2 Scrubber)	3	13000	11000	400-8000	Mid Range (1)
		1.8% Fuel Oil	2	6050	3000	NA	
		2.0% Fuel Oil	1	2800	1400	NA	
		No Known further controls	3	10000	0	0	
		Currently Controlled	21	4000	0	0	
Portland Cement	25	Fuel switching: CE of SOx 10%	3	2300	230	NA	
		No Further Controls Warranted	5	3700	0	0	
		No Known Further Controls	7	300	0	0	
		SO_2 Scrubber	10	26000	19000	400-8000	Mid Range (1)
Refinery	37	Refinery RACT	9	5400	NA	0	
		SO2 Scrubber	3	NA	NA	400-8000	Mid Range (1)
		No Known Further Controls	25	NA	NA	0	

(1) Cost estimate from NESCAUM 2005 for Industrial Boilers
NA- No information currently available.

Table 4-4. Possible range of NO_X controls and costs based on survey of state staff

Type of Source	*Number of Sources*	*Control Strategies*	*Number of Emission Units Control Strategy May Apply*	*Total 2002 NO_x Emissions*	*Total Estimated Decrease in NO_x (tons/yr)*	*Estimated Cost (\$/Ton NO_x)*	*Notes*
Chemical Manufacturer	3	SCR	1	4900	3400	1300-10000	(2)
		Currently Controlled	2	5000	0	0	
Glass Fiber	6	Currently Controlled	6	180	0	0	
Coal Cleaning	1	Low NOx burners, CE of 15%	1	160	25	1-2 Million (capital cost)	Low Range
EGU/Coal	5	Currently Controlled	2	2900	820	0	
		SCR and 1.5 lb/MWh	2	9800	NA	1000-1500	Mid Range (1)
		NOx Budget & 1.5 #/MWh	1	2300	NA	NA	
EGU/Oil	17	Currently Controlled	6	3200	0	0	
		No Known Controls	3	390	0	0	
		NOx Budget	3	700	NA	NA	
		NOx Budget and 1.5 lb/MWh	4	5300	NA	NA	
		SNCR, 1.5 lb/MWh	1	2400	NA	500-700	Mid Range (1)
Incinerator	1	Currently Controlled	2	720	0	NA	
Metal Production	2	Currently Controlled	2	0	0	0	
	5	No Further Controls Warranted	5	110	0	0	
Paper and Pulp	30	SCR or SNCR	2	710	430	1300-10000	Mid to High Range (2)
		No Known Further Controls	13	4500	0	0	
		Currently Controlled	15	4600	0	0	
Portland Cement	25	Low NOx burners	3	2800	430	200-3000	Mid Range (3)
		Low NO_x Burners and Mid Kiln Firing, 40% Reduction	2	8500	3400	1200-10000	Mid Range (2)
		SCR, 65% Red.	1	740	480	1300-10000	(2)
		No Known Further Controls	9	2000	0	0	
		Currently Controlled	1	1700	0	0	
		SNCR	9	7100	2900	900-1200	Mid Range (3)
Refinery	37	Refinery RACT	9	2300	NA	NA	
		No Known Further Controls	25	0	0	0	
		SCR	2	460	40	1300-10000	(2)
		SNCR	1	1000	560	1300-10000	(2)

(1) Cost estimate from NESCAUM 2005, EGU controls
(2) Cost estimate from NESCAUM 2005, Industrial Boiler controls
(3) Cost estimate from NESCAUM 2005, Portland Cement Kilns
NA-No information currently available.

Table 4-5. Possible range of PM_{10} controls and costs based on survey of state staff

Type of Source	*Number of Sources*	*Control Strategies*	*Number of Emission Units Control Strategy May Apply*	*Total 2002 PM_{10} Emissions*	*Total Estimated Decrease in PM_{10} (tons/yr)*	*Estimated Cost (\$/Ton PM_{10})*	*Notes*
Chemical Manufacturer	3	Currently Controlled	3	200	0	0	
Coal Cleaning	1	No Known Further Controls	1	46	0	0	
EGU/Coal	10	Currently Controlled ESP	7	2000	0	0	
		PM co-benefit reductions expected due to FGD-25-50% reduction	2	1500	370	0	
		Baghouse	1	1500	NA	$50 M	Capital Cost
EGU/Natural Gas	2	Controls information included with oil/coal boilers	2	13	NA	NA	
EGU/Oil	18	Currently Controlled	13	410	42	0	
		No Known Further Controls	5	50	0	0	
Incinerator	2	Currently Controlled Fabric Filter	2	0	0	0	
Glass Fiber	6	Currently Controlled	6	190	0	0	
Metal Production	7	Currently Controlled	7	41	0	0	
Paper and Pulp	30	Upgrade from ESP to baghouse, CE of 4% estimate	2	180	7	$15 M	Capital Cost
		No Known Further Controls	7	280	0	0	
		Currently Controlled (ESP, Venturi Scrubbers, Demister, or MultiCyclones)	9	690	0	0	
		Current Controls	7	670	0	NA	
Portland Cement	25	Upgrade on current ESP, CE of 5%	3	210	11	Limited Cost	
		No Known Further Controls	15	300	0	0	
		Currently Controlled	6	370	0	0	
		Baghouse or electric precipitator	1	4	NA	NA	
Refinery	37	No Known Further Controls	28	NA	0	0	
		Refinery RACT	9	270	NA	NA	

NA-No information currently available.

Table 4-3 through Table 4-5 display general summary information from state surveys on possible BART control efforts as well as cost information gathered from several sources. The sections below will describe the contents of these tables in further detail.

4.2.1. Chemical Manufacturers

In the MANE-VU region, one chemical manufacturing source showed visibility impacts greater than 0.1 dv at a Class I area. At this source the state is considering SO_2 scrubber installation at one boiler unit (emission unit containing three oil and coal fired boilers) that could result in a decrease of 9600 tons of SO_2 emitted from this source annually. The State is also considering an installation of an SCR (Selective Catalytic Reduction) at this unit that could result in a decrease of 3400 tons of NO_x emissions annually from the three boilers. This unit currently has an ESP installed for PM control which is expected to satisfy BART.

4.2.2. Glass Fiber

There is one glass fiber source in the region with a significant visibility impact on a Class I area in MANE-VU. Recent conversion from air/natural gas firing to oxygen/natural firing in 2000 has led to to an 85% reduction from the previous configuration which adequately satisfies BART.

4.2.3. Coal Cleaning

One coal cleaning source in the region showed a significant visibility impact at Class I areas. Low NO_X burners for NO_X control are considered a low-cost option for the thermal coal dryer unit at this source (Appendix B).. Additional control options for SO_2 and PM may not be warranted based on a survey of state staff. Low NO_X burners could result in approximately 24 tons of NO_X reduced annually.

4.2.4. Electric Generation Units

Of the 58 EGUs modeled in the region, 40 sources are located in states implementing a year-round CAIR program, while 15 sources are located in states implementing an ozone season CAIR program. Units covered in a year-round CAIR program were removed from further SO_2 and NO_X analysis because BART would likely be satisfied through CAIR requirements. Visibility modeling was conducted for all EGUs in the region and of the 18 EGU sources in MANE-VU states without a year-round CAIR program under development, 13 showed a significant impact at Class I areas in the region. In addition, three sources in states with a year-round CAIR program showed a significant PM impact, and were included in the PM control and cost analysis.

Coal-Fired Units

States with coal-fired EGU units are considering two options for SO_2 control; dry scrubber installation (a mid level cost option) and a 0.33 lb/mmBTU capacity limit. A dry scrubber could result in over 90 percent SO_2 decrease while a capacity limit of 0.33

lb/mmBTU could result in a decrease of 1200 tons SO_2 at one unit considering this option.

In terms of NO_X control, two boilers in the region have current controls of Low-NOx concentric firing systems and SCR that are being considered sufficient for BART. Two units are looking at SCR controls to achieve a 1.5 lb/MWh emission rate, a mid level cost option for this source. One unit's control level under the NO_X Budget Program will simultaneously control for BART.

The majority of coal-fired units at EGUs in the region are currently fit with ESPs and further PM control recommendations are not warranted. For the units without ESPs, one state was looking at baghouse installation as a possible option and another expects sufficient reductions due to a PM co-benefit from the installation of an FGD (Fluid Gas Desulfurization) scrubber for SO_2 control.

Oil-Fired Units

The majority of BART-eligible oil-fired EGU boilers in the region were found in one state. For these units, input- and output-based capacity limits established under other programs for which the BART-eligible units were covered may satisfy SO_2 BART control requirements. The levels of those programs are 0.56 and 1.1 lb/MMBtu for two different EGUs respectively, and 3.0 lb/MWh output-based limit for several other EGUs.

Another control option being considered by other states is a fuel sulfur limit (0.3 percent) or an equivalent 0.33 lb/MMBtu emissions rate. Four BART-eligible units in the region have been controlled at this level since 2002 and would consider this level of control appropriate for BART. This BART control option has reduced total SO_2 emissions by 3100 tons annually at the one controlled sources, but is not anticipated to achieve as great a reduction at the other three BART-eligible sources, which are smaller. One unit is considering a 1.5 percent fuel sulfur limit that could result in approximately 3900 tons (or approximately 75 percent reduction) of SO_2 emissions from the one candidate for this option. We have no information on potential controls for two other BART-eligible units in the region.

Regarding NO_X controls on oil-fired boilers, possible technologies being considered for BART include SNCR (Selective Non-Catalytic Reduction) installation. Several units in the region are either currently controlled, with further controls considered unwarranted, or are under a NO_X budget program that would serve as BART. Current controls on oil-fired boilers at EGUs include SNCR, boiler excess air control, and Low-NO_x burners. For several of these units, information on BART recommendations was unavailable.

As with the coal-fired units, the majority of oil-fired boilers in the region have existing PM control technologies like ESPs, multicyclones, and mechanical collectors.

4.2.5. Incinerators

The lone BART-eligible incinerator source in the region has already achieved an approximately 75 percent reduction in SO_2 emissions through the installation of a dry scrubber. This source already has SNCR NO_X controls and reverse air fabric filters for PM controls and therefore further controls are not warranted. The air pollution controls on this source are the same controls required by new municipal waste combustion facilities MACT requirements.

4.2.6. Metal Production

Two metal production sources consisting of seven BART eligible units showed significant visibility impact on the region For one source, the state was looking at low cost, better efficiency measures for the SO_2 scrubber that would result in an increase of SO_2 control efficiency by 10 percent at two aluminum ore reduction units. A preliminary cost analysis conducted by the state at another source showed that SO_2 controls were not warranted at the sources BART eligible units (baking furnaces and potlines). The survey of state staff indicated that current controls for PM would likely satisfy BART for all metal production units in the region. Two units in the region are currently controlled for NOx while a cost analysis for NO_x controls at 5 units indicated that no further controls were warranted.

4.2.7. Paper and Pulp

There are 30 eligible units at paper and pulp sources with significant visibility impact in the region. While the majority of these units are industrial boilers, this category also contains lime kilns, smelt tanks, and other process units. States are contemplating FGD scrubber installations for SO_2 control for at least three industrial boiler units as possible BART control options. This is a mid-range cost technology for typical installations that could result in an estimated 20,000 fewer tons of SO_2 for these three units alone. At three industrial boiler units, a fuel switching option is being considered by the state. Two boilers switching to 1.8% Sulfur fuel oil could result in 3000 tons of SO_2 being reduced while one boiler switching to 2.0% sulfur fuel oil could result in 1400 tons of SO_2 reduced. Twenty-one units are currently controlled at a level such that existing controls are likely to satisfy BART, while no known further controls are expected for three units in this category. Current controls on these boiler units are generally wet scrubbers.

For the majority of paper and pulp units, either the existing Low NO_X burner controls or current capacity limits may satisfy BART or we did not have information about possible controls for units. Possible control options being considered for uncontrolled sources include SCR or SNCR technologies on boilers that could achieve 60 to 80 percent NO_X control. This is a mid to high cost control option, depending on the source. Installation of these technologies is estimated to result in a decrease of 430 tons of NO_X emissions at two units considering this option.

Most of the units at paper and pulp sources with significant visibility impacts in the region have existing PM controls including ESPs, baghouses, multicyclones, and venturi scrubbers and were therefore not viewed as candidates for further controls. One state is considering upgrading ESPs on two coal fired industrial boilers to baghouses that would result in a decrease of 7 tons of PM emitted per year.

4.2.8. Portland Cement Plants

Twenty-five Portland cement units in MANE-VU are located at BART-eligible sources with significant visibility impacts on Class I areas in the region. At these sources, states are considering installation of SO_2 scrubbers at 10 cement kilns at these sources, which would significantly reduce the amount of SO_2 emitted from this sector. If installed, scrubbers at these kilns would result in a decrease in emissions of 19,000 tons of SO_2 annually.

Another BART control option being considered for cement kilns in the region is fuel switching. Units considering this option for kilns could decrease annual SO_2 emissions by 230 tons. Twelve units in this sector either have existing controls that will likely satisfy BART, or control information for SO_2 is currently unknown.

Control technologies under consideration for NO_X at cement plants were varied according to our survey information. Low NO_X burners are a possible control option for uncontrolled cement kilns. This is a mid range cost option that could result in an annual decrease of 430 tons of NO_X emitted from three units. Another possible control option is Low NO_X burners with mid-kiln firing. At a mid level cost, this technology could result in a decrease of 3400 annual tons of NO_X emissions at units where this option is applicable. SCR installation is being considered at one unit, also a mid level cost option that could decrease emissions from unit by 480 tons annually. SNCR control technology is a mid level cost option, which if in place at units considering this option, could result in a decrease of 2900 tons of NO_X emissions. Ten of the 25 units in this category either have existing controls that will likely satisfy BART or controls for NO_X are currently unknown.

Most of the units at these Portland cement plants either have existing PM controls or potential control information is unknown. Where no controls exist, possible control options include installation of a baghouse or an ESP. One state is considering a recommendation of upgrading ESPs at three units, a low cost option that would reduce annual emissions of PM by 11 tons.

4.2.9. Refineries

At this time, for the majority of the units in this category, control information is unknown. One possible control option for SO_2 is installation of a scrubber on fluid catalytic cracking units, a mid range cost option being considered for three units in the region. Nine of these units are currently subject to refinery RACT (Reasonably Available Control Technology) controls for 8-hour ozone and these control levels for SO_2, NO_X, and PM are likely to satisfy BART requirements. States are also considering SCR or SNCR controls for three fluid catalytic cracking units in the region for possible NO_X control, also a mid level cost option.

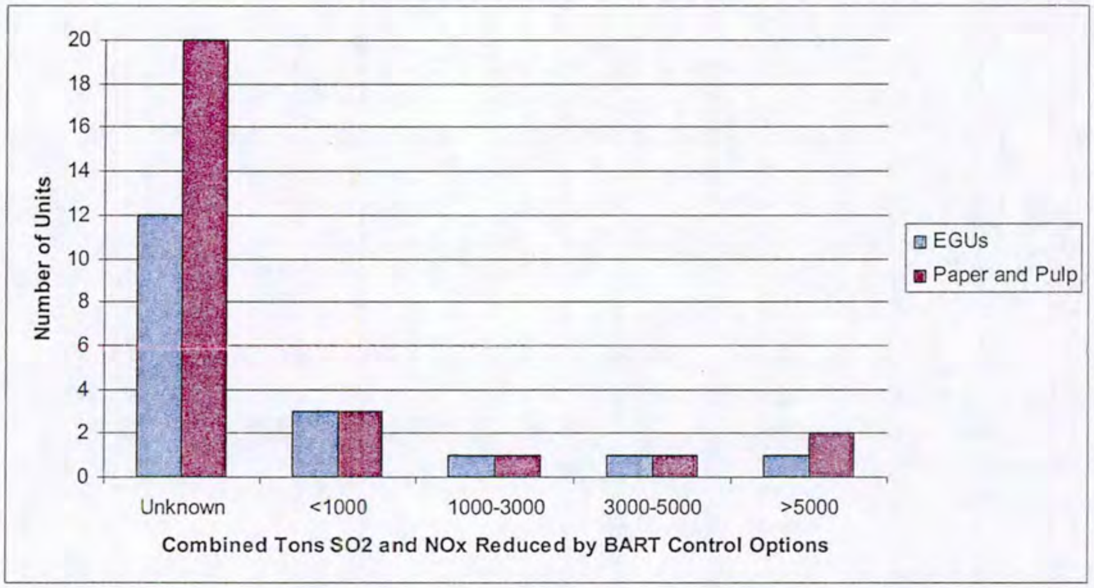
4.3. Energy and Non-Air Quality Environmental Impacts

While there are certain to be several issues that arise on a source-specific basis with respect to individual control technologies (e.g., water quality impacts or solid waste disposal issues), we are unable to address these issues in a regional analysis. One environmental benefit that should be considered in weighing control options for BART is the regional impact on acid deposition in MANE-VU.

An analysis of combined SO_2 and NO_X reduction potential of BART control options by sector showed similar results for EGUs and paper and pulp sources. Figure

4-1 shows the amount of SO_2 and NO_X that could be reduced if BART control options were implemented at the units for which likely control options are known. Figure 4-1 shows that generally, when emission reduction options are known, the emissions reduction potential is evenly distributed across the range of sources in the region. This is important as states are weighing whether controls are warranted or not for EGUs or paper and pulp boilers. However, for the majority of units with significant visibility impact in these sectors, the amount of SO_2 and NO_X reduction potential is currently unknown, limiting the power of this analysis.

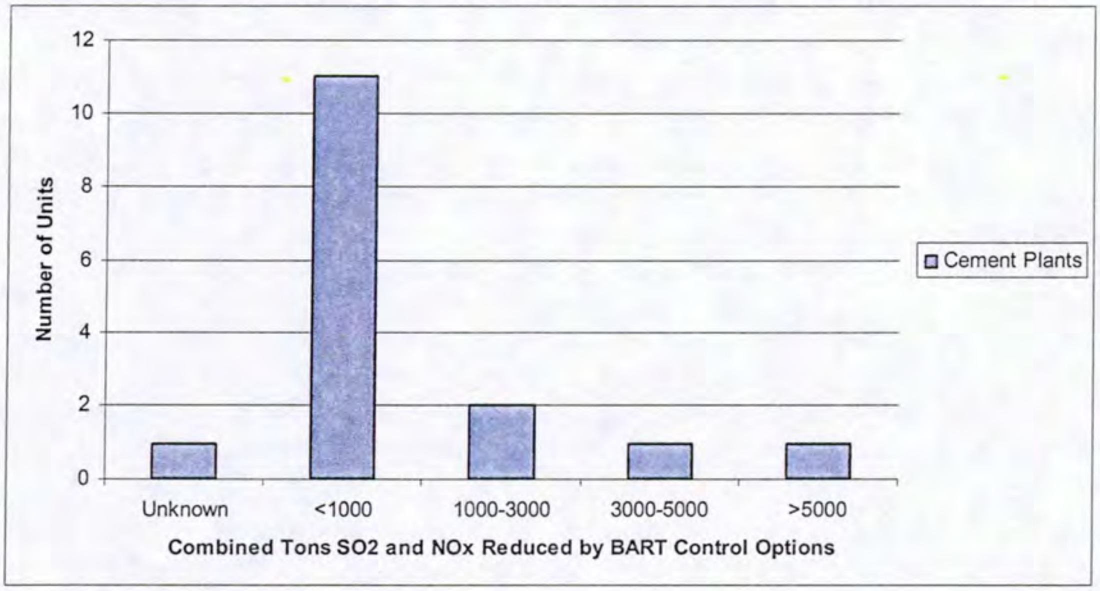
Figure 4-1. Reduction potential of BART control options at EGUs and Paper and Pulp Sources



For Portland cement plants, possible emissions reduction data were more complete and allowed for a clearer analysis of SO_2 and NO_X control. Figure 4-2 shows the emissions reduction potential that would be achieved by BART if the survey control options were implemented for units in this sector. While several units would benefit from BART control options with emissions being reduced by greater than 3,000 tons of combined SO_2 and NO_X, the majority of the cement plant units would reduce emissions by less than 1,000 tons. As states weigh whether additional controls are warranted for cement plants, this non air-quality environmental factor may play less of a role for these sources.

For other source categories, the statistics are generally too small to make an analysis meaningful, but as a general rule, the remaining source categories tend to have lower overall emissions and lower overall reduction potential, which may factor into control decisions accordingly.

Figure 4-2. Reduction potential of BART control options at Cement Plants



4.4. Remaining Useful Life

The MANE-VU BART Workgroup has considered what weight to give to this factor in conducting BART determinations and has recommended that remaining useful life of a source will be addressed in the following way. A BART-eligible source that is found to have reasonable control options available to it should either control emissions from that BART-eligible source prior to 2013 or accept a federally enforceable permit limitation or retirement date prior to each state's public notice and hearing processes and FLM review of BART SIP elements.

5. CONCLUSIONS

As MANE-VU states prepare to conduct source-specific BART determinations for the eligible units in their jurisdictions, this report provides a regional assessment of the five factors that must be considered in determining whether additional controls are warranted for an individual BART source. This information is intended to lay out a regional approach and provide regional context for individual control decisions that will be made by the MANE-VU member states. This information may also serve as an important regional basis for dialogue and internal MANE-VU consultations as states consider what level of stringency is justified and reasonable based on consideration of the five factors.

Important findings of this analysis include the identification of BART-eligible sources in the region, the numbers of units in various categories subject to BART consideration, BART control technology options being considered in the region, and estimates of the total emissions and reduction potential from units contributing to potentially significant visibility impacts at Class I areas.

Table 4-1 and Table 4-2 indicate that 136 BART-eligible sources exist in the region with 53 contributing to potentially significant visibility impairment at a Class I area. The majority of BART-eligible sources in the region are EGUs, however, most of these sources fall under a year-round CAIR program that will satisfy BART.

Of the BART-eligible source categories with potentially significant visibility impacts, the non-CAIR EGU sector was the largest emitter of SO_2, NO_X, and PM_{10} in 2002. BART-eligible EGUs with significant visibility impacts included 17 sources with 30 units emitting 110,000 tons SO_2, 28,000 tons NO_X, and 7,000 tons PM_{10} in 2002. The majority of these units are anticipating controls for SO_2 and NO_X to satisfy BART requirements. Although the amount of expected reductions is currently unknown, we can expect significant reductions in emissions from this sector given widely available control technologies for SO_2 and NO_X with proven cost-effectiveness. Most of these units are currently controlled for particulate matter and further controls are not expected.

Portland cement plants and paper and pulp sources are sectors with many BART-eligible units that made significant contributions to visibility impairment and total pollutant emissions in the region. Paper and pulp sources with significant visibility impacts emitted 36,000 tons SO_2, 10,000 tons NO_X, and 2,000 ton PM_{10} at 30 units in 2002. Although information on controls is currently unknown for many of these units, information from units considering controls indicates that significant reductions can be achieved from this sector (19,000 tons SO_2 reduced if scrubbers are installed at 13 units and 400 tons NO_X reduced if SCR controls are introduced to two units). Portland cement sources with significant visibility impacts emitted 32,000 tons SO_2, 23,000 tons NO_X, and 850 tons PM_{10} at 25 units in the region. With more complete information for cement plants, we estimated a reduction of 19,000 tons SO_2 at 13 units and 7,000 tons NO_X at 15 units when considering controls that would satisfy BART.

Ultimately, the strength of the MANE-VU BART program, as determined by individual state control decisions and informed by this analysis, will demonstrate MANE-VU's resolve to tackle visibility and related air quality problems in its region. As MANE-VU enters into inter-RPO consultations, its willingness to seek reasonable emission reductions within its own region will help set expectations for the other RPOs, and the BART program represents a cornerstone of this process.

6. REFERENCES

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Appendix A: List of BART-Eligible Sources in the MANE-VU Region

State	Plant	Type	Number of Units
CT	Middletown Power LLC (NRG)	EGU	2
CT	Montville Power LLC (NRG)	EGU	1
CT	Norwalk Power LLC (NRG)	EGU	1
CT	PSEG Power CT Bridgeport Harbor Station	EGU	1
CT	PSEG Power CT New Haven Harbor Station	EGU	1
CT	Sprague Paperboard Caraustar	Fossil Fuel Boiler (>250 MMBtu	1
DC	Benning (PEPCO -15)	EGU	1
DC	Benning (PEPCO -16)	EGU	1
DE	City of Dover - Mckee Run	EGU	1
DE	Connectiv Edgemore	EGU	2
DE	NRG- Indian River	EGU	1
MA	Exxon Mobil Everett	Petroleum Storage	1
MA	Global Petroleum Revere	Petroleum Storage	1
MA	Gulf Oil Chelsea	Petroleum Storage	1
MA	Solutia	Chemical Process Plant	3
MA	Braintree Electric	EGU	1
MA	Brayton Point	EGU	4
MA	Eastman Gelatin (boilers only)	Chemical Process Plant/Industrial Boilers	4
MA	General Electric Lynn	EGU	1
MA	Harvard U (Blackstone)	EGU	2
MA	Mirant Kendall LLC	EGU	3
MA	Mirant-Canal Electric	EGU	2
MA	Mystic	EGU	1
MA	New Boston	EGU	1
MA	Salem Harbor	EGU	1
MA	TMLP - Cleary Flood	EGU	3
MA	Trigen - Kneeland St	EGU	1
MA	Wheelabrator -Saugus	Municipal Incinerator	2
MD	CONSTELLATION POWER SOURCE GENERATION CP CRANE	EGU	7
MD	CONSTELLATION POWER SOURCE GENERATION HERBERT WAGNER	EGU	2
MD	EASTALCO ALUMINUM	Primary Aluminum Ore Reduction Plant	2
MD	INDEPENDENT CEMENT ST LAWERENCE	Portland Cement	1
MD	LEHIGH PORTLAND CEMENT	Portland Cement	3

MD	METTIKI COAL CORPORATION	Coal Cleaning	1
MD	MILLENIUM INORGANIC CHEMICALS	Chemical Process Plants	5
MD	MIRANT MID ATLANTIC LLC MORGANTOWN	EGU	2
MD	MIRANT MID ATLANTIC DICKERSON	EGU	1
MD	PEPCO CHALK POINT	EGU	3
MD	TRIGEN LEADENHALL STREET	Fossil Fuel Boiler (>250 MMBtu	4
MD	VIENNA GENERATING STATION	EGU	1
MD	WESTVACO FINE PAPERS	Kraft Pulp Mill/Fossil Fuel Boiler (>250 MMBtu	3
ME	Domtar Ind	Industrial Boiler/Kraft Pulp Mill	2
ME	Dragon Products	Portland Cement	1
ME	Georgia Pacific Old Town	Industrial Boiler/Kraft Pulp Mill	2
ME	IP Bucksport	Fossil Fuel Boiler (>250 MMBtu	1
ME	IP Jay	Industrial Boiler/ Kraft Pulp Mill	9
ME	Katahdin Paper Millinocket	Fossil Fuel Boiler (>250 MMBtu	1
ME	Lincoln Paper and Tissue	Industrial Boiler/Kraft Pulp Mill	2
ME	Rumford Paper	Industrial Boiler	1
ME	SAPPI Somerset	Industrial Boiler/Kraft Pulp Mill	4
ME	Wyman Station	EGU	2
NH	PSNH Merrimack Station	EGU	1
NH	PSNH Newington Station	EGU	1
NJ	Amerada Hess Corporation-Port Reading Re	Petroleum Refinery	13
NJ	Bayway Refinery	Petroleum Refinery	257
NJ	Chevron Products Company	Petroleum Refinery	22
NJ	COASTAL EAGLE POINT OIL COMPANY	Petroleum Refinery	145
NJ	Hudson Generation Station	EGU	4
NY	3M TONAWANDA	Chemical Process Plants/Industrial Boilers	4
NY	ALCAN ALUMINUM CORPORATION	Primary and Secondary Aluminum Production	9
NY	ALCOA MASSENA OPERATIONS (WEST PLANT)	Primary and Secondary Aluminum Production	25
NY	ARTHUR KILL GENERATING STATION	EGU	2
NY	ASTORIA GENERATING STATION	EGU	2
NY	BOWLINE POINT GENERATING STATION	EGU	5

NY	BUFFALO COLOR CORP - LEE ST PLANT	Chemical Process Plants/Industrial Boilers	5
NY	CON ED-59TH ST STA	EGU	4
NY	DANSKAMMER GENERATING STATION	EGU	2
NY	EF BARRETT POWER STATION	EGU	44
NY	ERWIN MANUFACTURING COMPLEX	Glass Fiber Processing Plants	3
NY	GENERAL ELECTRIC SELKIRK PLASTICS PLT	Chemical Process Plants/Industrial Boilers	16
NY	GLENS FALLS LEHIGH CEMENT COMPANY	Portland Cement	46
NY	INTERFACE SOLUTIONS INC	Kraft Pulp Mill/Industrial Boilers	9
NY	INTERNATIONAL PAPER TICONDEROGA MILL	Kraft Pulp Mill/Industrial Boilers	11
NY	KODAK PARK DIVISION	Chemical Process Plants/Industrial Boilers	20
NY	LACKAWANNA PLANT- REPUBLIC ENG PROD INC	Primary Metal Production/Industrial Boilers	3
NY	LAFARGE BUILDING MATERIALS INC	Portland Cement	31
NY	LOVETT GENERATING STATION	EGU	4
NY	NORTHPORT POWER STATION	EGU	17
NY	OSWEGO HARBOR POWER	EGU	3
NY	OWENS-CORNING DELMAR PLANT	Glass Fiber Processing Plants	27
NY	RAVENSWOOD GENERATING STATION	EGU	60
NY	REVERE SMELTING & REFINING CORP	Primary Metal Production/Industrial Boilers	8
NY	RIVERBAY CORP-CO-OP CITY	Industrial Boilers	4
NY	RIVERHEAD TERMINAL-CONOCOPHILLIPS	Petroleum Storage/Industrial Boilers	7
NY	ROSETON GENERATING STATION	EGU	4
NY	SAMUEL A CARLSON GENERATING STATION	EGU	2
NY	SCHENECTADY INTERNATIONAL ROTT JCT FAC	Chemical Plant/Industrial Boilers	18
NY	ST LAWRENCE CEMENT CORP-CATSKILL QUARRY	Portland Cement	37
NY	WASHINGTON MILLS ELECTRO MINERALS	Glass Fiber Processing Plants	3
PA	ALLEGHENY_LUDLUM_CORP_BRACKENRIDGE	EGU	8
PA	EASTMAN_CHEMICAL_RESINS_INC	Chemical Process Plants/Industrial Boilers	2
PA	ESSROC/BESSEMER	Portland Cement	14

PA	NEVILLE_CHEMICAL_COMPANY	Chemical Process Plants	5
PA	ORION_POWER_MIDWEST_CHESWICK_STATION	EGU	2
PA	USS_CLAIRTON_WORKS	Metal Production/Industrial Boilers	4
PA	AK STEEL CORP BUTLER WORKS	Iron and Steel Mill Plants	16
PA	ALLEGHENY ENERGY SUPPLY CO HATFIELDS FER	EGU	5
PA	ALLEGHENY ENERGY SUPPLY CO MITCHELL POWE	EGU	19
PA	AMER REF GROUP BRADFORD	Petroleum Refinery	4
PA	APPLETON PAPERS SPRING MILL	Kraft Pulp Mill/Industrial Boilers	9
PA	CARMEUSE LIME INC MILLARD LIME PLT	Lime Plant	8
PA	CEMEX INC WAMPUM CEMENT PLT	Portland Cement	9
PA	CONOCOPHILLIPS CO TRAINER REF	Petroleum Refinery	10
PA	DUFERCO FARRELL CORP FARRELL PLT	Iron and Steel Mill Plants	1
PA	DYNO NOBEL INC DONORA	Chemical Process Plants	9
PA	ESSROC NAZARETH LOWER CEMENT PLT 1	Portland Cement	1
PA	EXELON GENERATION CO EDDYSTONE	EGU	6
PA	EXIDE TECH READING SMELTER	Secondary Metal Production	9
PA	HOMER CITY OL HOMER CITY GEN STA	EGU	6
PA	HORSEHEAD CORP MONACA SMELTER	Primary Zinc Smelter	25
PA	INDSPEC CHEM CORP PETROLIA	Chemical Process Plants	17
PA	INMETCO ELLWOOD CITY	Iron and Steel Mill Plants	6
PA	ISG PLATE LLC COATESVILLE	Iron and Steel Mill Plants	20
PA	KEYSTONE PORTLAND CEMENT EAST ALLEN	Portland Cement	4
PA	LAFARGE CORP WHITEHALL PLT	Portland Cement	28
PA	LEHIGH CEMENT CO EVANSVILLE CEMENT PLT	Portland Cement	42
PA	LEHIGH CEMENT CO YORK OPERATIONS	Portland Cement	11
PA	LWB REFRACTORIES CO W MANCHESTER	Mineral Products	13
PA	MERCER LIME & STONE BRANCHTON	Lime Plant	6
PA	NEW CASTLE POWER PLT	EGU	2
PA	PA POWER CO BRUCE MANSFIELD PLT	EGU	18
PA	PH GLATFELTER CO SPRING GROVE	Paper and Pulp/Industrial Boilers	8
PA	PPL BRUNNER ISLAND L BRUNNER ISLAND	EGU	4
PA	PPL MARTINS CREEK LLC MARTINS CREEK	EGU	2
PA	PPL MONTOUR LLC MONTOUR SES	EGU	4
PA	RELIANT ENERGY NORTHEAST CONEMAUGH PLT	EGU	6
PA	RELIANT ENERGY NORTHEAST MGMT KEYSTONE POWER PLT	EGU	2
PA	RELIANT ENERGY PORTLAND GENERATING STATION	EGU	2
PA	SUNOCO CHEMICALS (FORMER ALLIED SIGNAL)	Chemical Process	17

		Plants	
PA	SUNOCO INC (R&M) MARCUS HOOK REFINERY	Refinery	10
PA	SUNOCO INC (R&M)	Refinery	26
PA	TRIGEN - EDISON	EGU	4
PA	TRIGEN - SCHUYLKILL	EGU	1
PA	UNITED REFINING CO WARREN PLT	Refinery	10
PA	VICTAULIC CO AMER FORKS FACILITY	Secondary Metal Production	12

Appendix B: Costs of Technologies

From NESCAUM, 2005.

EGU **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
SO2	Wet/Dry Scrubbers (FGD)	200-500	Dollars per ton SO2	Low
NOx	Gas Reburn	500-2000	Dollars per ton NOx	Mid
NOx	Low-NOx Burners	200-500	Dollars per ton NOx	Low
NOx	Overfire Air	250-600	Dollars per ton NOx	Low
NOx	SCR	1000-1500	Dollars per ton NOx	Mid
NOx	SNCR	500-700	Dollars per ton NOx	Mid
PM	ESP	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Fabric Filters	12-40	Dollars per Actual Cubic Feet per Minute	

Industrial Boilers **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
NOx	Low NOx-Burners	200-3000	Dollars per ton NOx	Mid
NOx	SNCR	1300-10000	Dollars per ton NOx	Mid to High
NOx	SCR	4000-15000	dollars per MMBtu/hr	High
SO2	Wet/Dry Scrubbers	400-4000	Dollars per ton SO2 (coal)	Mid
SO2	Wet/Dry Scrubbers	800-8000	Dollars per ton SO2 (oil)	Mid to High
PM	ESP	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Reverse Air Fabric Filter	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Pule Jet Fabric Filter	17-40	Dollars per Actual Cubic Feet per Minute	
PM	Venturi Scrubber	12-40	Dollars per Actual Cubic Feet per Minute	
PM	Cyclone	1-5	Dollars per Actual Cubic Feet per Minute	

Portland Cement Kilns **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
SO2	Spray Dryer	10.96-54.67	dollars/ton Clinker	
SO2	Wet Scrubber	10.83-47.00	dollars/ton Clinker	
NOx	Process Modifications	3100-8800	Dollars per ton NOx	Mid to High
NOx	Low NOx Burners w/Indirect Firing	5800-8100	Dollars per ton NOx	High
NOx	Low NOx Burners w/Indirect Firing and Mid-Kiln Tire Injection	1-1800	Dollars per ton NOx	Low to Mid
NOx	Mid-Kiln Injection of Fuel	5100-11500	Dollars per ton NOx	Mid to High
NOx	CemStar	0-600	Dollars per ton NOx	Low
NOx	Low NOx Precalciner	2700-3600	Dollars per ton NOx	Mid
NOx	SNCR	900-1200	Dollars per ton NOx	Mid
NOx	Biosolids Injection	100-1800	Dollars per ton NOx	Low to Mid
PM	ESP	3.33-41.00	dollars/ton clinker	
PM	Baghouse	4.00-16.67	dollars/ton clinker	

Paper and Pulp

Cost Effectiveness Not Available

Cost levels	*SO2*	*NOx*
Low	<800	<500
Mid	800-2000	500-10000
High	>2000	>10000

Appendix C: BART Workgroup Draft Recommendations

Draft BART Recommendations
to MANE-VU Air Directors
September 7, 2006

Under the U.S. Environmental Protection Agency's (USEPA) 1999 "regional haze rule" [64 Fed. Reg. 35714 (July 1, 1999)], certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART).[6] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act (CAA).

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments (CAAA), which first required new source performance standards).

MANE-VU formed the BART workgroup as part of an effort to assist states and tribes as they prepare to comply with the Best Available Retrofit Technology Requirements (BART) of the Regional Haze Rule. To date states have made substantial progress in identifying sources that are BART-eligible, however that is only the first step in the process. Once a source is identified as "BART eligible", an analysis must be conducted to determine what will constitute BART control levels. The Haze Rule requires states to determine the most stringent technologically feasible system of controls that can reasonably be installed at each source eligible for BART. The BART workgroup has developed a list of draft recommendations for the BART control process that will be submitted to the MANE-VU Directors. Feedback on these recommendations will be useful to assist the Air Directors in their review. The recommendations include overall BART policies and specific "presumptive" levels and types of control. These recommendations will serve as a regional foundation for conducting BART engineering reviews on a state-by-state basis. The workgroup recommendations are presented below:

1. ***Any BART-eligible facility may "cap-out" of BART via a permit emission limit, however all permit modifications must be finalized prior to December 16, 2006* in order to eliminate BART-eligibility.*** Caps must limit emissions from BART eligible units below 250 tons per year of any visibility impairing pollutant

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[6] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

* It is not clear from the final rule when a federally enforceable permit limitation would need to be in place in order to avoid BART-eligibility. We are recommending to EPA that they allow permit limits which go into place prior to December 16, 2006. This will enable states to take action to get permit limitations in place and achieve emission limits (though probably not reductions) prior to SIP submission avoiding the need for formal BART determinations. The 2006 date will give states one full year prior to the submission deadline for public notice and hearing processes on a final SIP package.

2. MANE-VU staff continues to support the policy decision made by the MANE-VU Board in June 2004, that ***if a source is eligible for BART, it is subject to BART***. (i.e. no exemptions will be given).

3. ***Regional performance standards or cost thresholds are appropriate*** for many individual categories of BART eligible sources. The attachment contains an initial round of recommended presumptive levels of control for EGUs, industrial boilers and cement kilns. The workgroup may develop additional presumptive levels in the future.

4. ***Remaining useful life*** of a source will be considered in the following way: Sources have the option to ***either control a BART-eligible facility prior to 2013 or accept federally enforceable permit limitation or retirement date prior to December 16, 2006.***

5. ***Control technology in place*** (other than for source categories covered by the attached list of presumptive control levels) ***will likely have to be dealt with on a source by source basis***. (i.e. no regional recommendation)

6. ***Energy and non-air quality environmental impacts will likely have to be dealt with on a source by source basis***. (i.e. no regional recommendation) however the workgroup is still considering regional recommendations for non-air quality environmental impacts.

7. ***If data does not exist*** to accurately determine the installation date for emission unit(s)within a facility ***then the unit will be treated as though it IS within the BART date range unless the facility can provide proof otherwise (i.e., proof that the unit was in operation prior to 1962)***. Many states are having difficulty identifying installation dates for pre-1977 units. All states felt they could easily identify post-1977 units. Therefore, the workgroup supported a policy position that when the state could not accurately determine the "in existence" date, the burden of proof lay with the facility in proving that the unit was installed prior to 1962.

MANE-VU BART Workgroup Recommendations
DRAFT Presumptive Control Levels
Updated September 7, 2006

Non-CAIR EGUs:

- SO_2 – Coal - 95% control or 0.15 lb/MMBtu*
  Oil - 95% control or 0.33 lb/MMBtu (0.3% sulfur content)*
- NO_X
  - in NO_X SIP call area, extend use of controls to year-round
  - 0.1 – 0.25 lb/MMBtu, depending on boiler and fuel type
- PM – 0.02 – 0.04 lb/MMBtu**

CAIR EGUs:

- SO_2 – CAIR requirements
- NO_X – CAIR requirements
- PM – 0.02- 0.04 lb/MMBtu**

If an EGU is only enrolled in CAIR for one or two pollutants, it still must complete an analysis for the remaining visibility impairing pollutants such as particulate matter.

Industrial Boilers

- SO_2 – 90% control, MACT acid gas control level, ICI-RACT, or 0.55 lb/MMBtu (0.5% fuel sulfur limit)
- NO_X
  - 0.1 – 0.4 lb/MMBtu, depending on boiler and fuel type***
- PM – 0.02 - 0.07 lb/MMBtu

Cement Kilns

No common emission threshold has been identified. The following lists, however, recommend control technologies to evaluate.

- SO_2
  - in process removal
  - wet or dry scrubbers
  - conversion from wet kiln to dry kiln
- NO_X
  - Combustion optimization
  - Low NO_X burners
  - Secondary combustion control (SNCR/SCR)
  - Mid-Kiln firing
  - Flame shape adjustment
- PM
  - baghouse
  - electrostatic precipitator
  - baghouse/ESP upgrades of existing controls

*Consistent with EPA presumptive BART for EGUs and OTC Control Strategy

** PM measures are based on front-half (Method 5) particulate matter measures

*** Consistent with OTC Control Strategies and NO_X SIP call emission limits

ATTACHMENT X

BART Analyses for Sources in New Hampshire

BART Analysis for
PSNH Merrimack Station Unit MK2

January 14, 2011
Amended August 26, 2011

BART Analysis for PSNH Merrimack Station Unit MK2

1. INTRODUCTION

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2 is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 MMBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators operate in series to capture particulate matter (PM) in the flue gases. Also, construction is nearing completion on a limestone forced oxidation scrubber system that will reduce sulfur dioxide (SO_2) emissions. Retrofit options for this unit are limited because the facility already has controls in place for these major pollutants of concern. Only a few emission control technologies are compatible with the type of boiler design employed, and space for new retrofits is very limited.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

Because of the current boiler design, the only NO_X emission control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction and selective catalytic reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on coal-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit (EGU) the size of Unit MK2. For SNCR, the total annual cost is estimated to be about $5,110,000, or $593/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be $5,070,000, or $312/ton. Stated costs are for year-round operation.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	12.1	3,880,000	4,780,000	5,110,000	593
SCR	117.8	37,710,000	1,910,000	5,070,000	312

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and 2,243 million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 8,613 tons of NO_X removed for SNCR and an estimated 16,269 tons of NO_X removed for SCR.

Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about $400/ton for year-round operation and about $600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to $530/ton and $790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NO_X RACT requirements.

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

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy. (In the case of Unit MK2, the existing fan was sufficient to accommodate the additional pressure drop.)

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

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

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag.

The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. Estimated PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	23.3-62.1 million	1.1-1.9 million	3.0-7.1 million	100-240
Wet ESP	73-194	23.3-62.1 million	0.6-1.6 million	2.6-6.8 million	90-230
Fabric filter – reverse air	82-194	26.4-62.1 million	1.6-2.4 million	3.8-7.6 million	130-260
Fabric filter – pulse jet	58-194	18.6-62.1 million	2.2-3.1 million	3.7-8.3 million	130-280

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and flue gas flow rate of 1.36 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 29,850 tons of PM removed for ESPs and 29,759 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about \$2.6 million to \$8.3 million, or \$90 to \$280 per ton of PM removed. Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of \$10,000 to \$30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit MK2 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule).

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Coal

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. Usually, for operational reasons, a facility cannot make a complete switch from one fuel type to another. Instead, the facility may be able to blend different fuels to obtain a lower-sulfur mix that emits less SO_2 upon combustion – for example, blending low-sulfur bituminous or subbituminous coal with a high-sulfur bituminous coal. The feasibility of fuel switching or blending depends on the physical characteristics of the plant (including boiler type), and significant modifications to systems and equipment may be necessary to accommodate the change in fuels. Switching to a lower-sulfur coal can affect coal handling and preparation systems, ash handling systems, boiler performance, and the effectiveness of PM emission controls. To meet federal acid rain requirements, many facilities have switched to lower-sulfur coals, resulting in SO_2 emission reductions of 50 to 80 percent.

2.3.1 Potential Costs of SO_2 Controls

PSNH Merrimack Station is required by New Hampshire law to install an FGD system to reduce mercury emissions (with SO_2 removal as a co-benefit) at both Unit MK1 (not a BART-eligible unit) and Unit MK2 (a BART-eligible unit). A company estimate for the project placed the capital cost at $457 million, or $1,055/kW (both amounts in 2008$) to install a wet limestone FGD system. Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MK1 and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost translates to about $1,400 per ton of SO_2 removed.

The project cost is said to be in line with the costs of multiple-unit scrubber installations occurring elsewhere in the country. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

The costs of switching to lower-sulfur coal at PSNH Merrimack Station would rest on the incremental cost of purchasing the lower-sulfur material at prevailing market prices. Even if a lower-sulfur coal is available at reasonable additional cost, operational considerations related to the physical characteristics of Unit MK2 may dictate the choice of coal for this unit. (Only certain types of coal can be used in wet-bottom, cyclone boilers; and lower-sulfur coals have already been tested and adopted for regular use at this facility.) Commodity spot prices for coal vary considerably. For example, from late March to early May 2009, the price spread between Northern Appalachia coal (<3.0 SO_2) and Central Appalachia coal (1.2 SO_2) ranged from $10 to $25 per ton (source: Energy Information Administration, http://www.eia.doe.gov/fuelcoal.html).

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired, wet-bottom, cyclone boiler in the United States. The SCR was designed to meet NO_X Reasonably Available Control Technology (RACT) limits. Specifically, Unit MK2 is subject to a NO_X RACT Order limit of 15.4 tons per calendar day and a second NO_X RACT Order limit of 29.1 tons per calendar day for combined emissions from Units MK1 and MK2. The facility must also meet a less stringent federal acid rain program limit of 0.86 lb NO_X/MMBtu. PSNH has a monetary incentive to surpass the NO_X RACT requirements because further emission reductions allow the utility to accumulate DERs. Actual NO_X emissions for Unit MK2 were reported as 2,871 tons in baseline year 2002.

Since January 2001, the SCR on Unit MK2 has reduced NO_X emissions to between 0.15 and 0.37 lb/MMBtu (calendar monthly average), with a few excursions outside this range. (Note that the existing NO_X RACT limit of 15.4 tons per calendar day is mathematically equivalent to 0.37 lb/MMBtu.) Data available from the period of 1993 to early 1995, prior to operation of the SCR, provide a baseline for uncontrolled NO_X emissions in the range of 2.0 to 2.5

lb/MMBtu. Taken together, this information indicates that Unit MK2 achieves a control level that exceeds 85 percent most of the time and frequently surpasses 90 percent.

3.2 Discussion of Current PM Emissions and Controls

PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. The ESPs have been upgraded with state-of-the-art electronic controls. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/MMBtu and a TSP emissions cap of 3,458.6 tons/year. However, the 0.227 lb/MMBtu rate does not reflect the true capabilities of the ESPs to control particulate emissions. Stack testing on three separate dates in 1999 and 2000 found actual TSP emissions to be 0.043, 0.041, and 0.021 lb/MMBtu after controls. The most recent test, in May 2009, produced an emission rate of 0.032 lb/MMBtu. Total TSP emissions from this unit were 210 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both Unit MK1 and Unit MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. The specific language of the permit states as follows:

> Beginning on July 1, 2013,…SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal)…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,…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...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.

These permit conditions effectively require that actual SO_2 removal efficiencies *exceed* 90 percent on average for Unit MK2. This plant must also meet general regulations for coal-burning devices that limit the sulfur content of the coal to 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period, and 2.8 pounds per million BTU gross heat content at any time. Since 2002, the facility has operated well within these fuel limits. More specifically, PSNH has worked to control coal sulfur content to reduce SO_2 emissions and minimize the purchase of SO_2 allowances. Because the particular boiler design does not permit the burning of straight low-sulfur coal, the company blends coals to bring average sulfur content to a level that is consistent with sustainable boiler operations.

PSNH must also meet a fleet-wide SO_2 emissions cap of 55,150 tons/year effective for all electrical generating units at its Merrimack, Newington, and Schiller Stations. In 2002, actual SO_2 emissions from Unit MK2 were 20,902 tons.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Merrimack Station Unit MK2 was built in 1968. PSNH's commitment to install new emission controls on this unit demonstrates the company's belief that this unit is capable of supplying electricity to the region for many years beyond the present.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

The New Hampshire Department of Environmental Services (NHDES) conducted a CALPUFF modeling analysis to assess the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Visibility can be quantified using deciviews (dv), a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye. NHDES conducted a set of CALPUFF runs for Unit MK2 under controlled and uncontrolled conditions. Before considering the findings of this modeling work, it is useful to review the results of the BART eligibility modeling performed by the Mid-Atlantic/Northeast Visibility Union (MANE-VU).

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit MK2 produce theoretical CALPUFF worst-case impacts of 2.24 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit MK2 exceed all of these exemption levels.

The BART assessment modeling provides a comparison of visibility impacts from current allowable emissions with those from the post-control emission level (or levels) being assessed. Results are tabulated for the average of the 20% worst natural visibility (about 11.7 to 12.4 dv) and 20% worst baseline visibility (about 22.8 dv) modeled days at each nearby Class I area. For any pair of control levels evaluated, the difference in the level of impairment predicted is the degree of improvement in visibility expected.

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

Table 5-1. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls

On the 20% Worst Natural Visibilty Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	1.07	0.83	**0.17**
NOx	Additional 25% with SCR upgrade	0.21	0.18	**0.10**
PM	90% with upgraded controls	0.16	0.12	**0.03**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	**0.26**	**0.20**	0.03
NOx	Additional 25% with SCR upgrade	**0.07**	**0.06**	0.03
PM	90% with upgraded controls	**0.07**	**0.05**	<0.01*

* below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

While the full impact of Unit MK2 was predicted to be as large as 2.24 dv at Acadia National Park under natural conditions, the predicted visibility benefit from a 90% reduction in sulfur emissions at Unit MK2 on the most visibility-impaired days is only 0.26 dv. At first this result may appear to be too low; however, on further examination, it is found that CALPUFF predicts the same amount of sulfate from Unit MK2 reaching Acadia under both best and worst visibility conditions. The difference is that there is greater than an order of magnitude more sulfate coming from other sources on the 20% worst visibility days, raising the background concentrations to much higher levels. Because the deciview scale is logarithmic, the same mass reduction of 0.259 $\mu g/m^3$ of sulfate from this one source results in wide differences in deciview impacts for different background visibility conditions at opposite ends of the range.

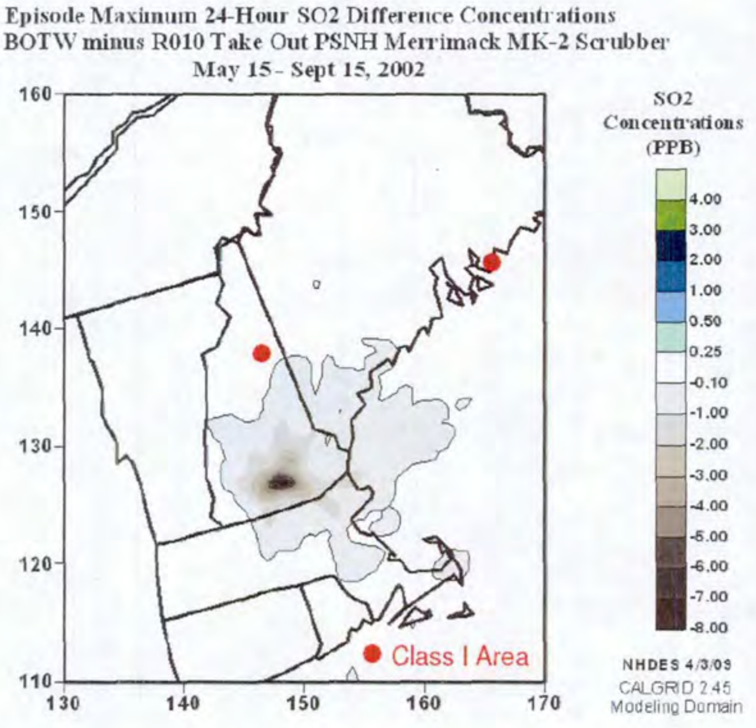
5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) and used MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, the installation of scrubber technology with 90% removal efficiency on Unit MK2 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume; see Figure 5-1) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

Figure 5-1



Episode Maximum 24-Hour SO2 Difference Concentrations
2018 BOTW minus R010 Take Out PSNH Merrimack MK-2 Scrubber
May 15 - Sept 15, 2002

NHDES's use of CALGRID differs somewhat from EPA's preferred methodology. CALPUFF is EPA's preferred model for performing long-range visibility assessments of individual sources to distant Class I areas, in part because it is considered to be a conservative model or one that is capable of estimating worst-case impacts rather than expected impacts. This makes CALPUFF ideally suited to screening BART sources for exemption purposes because it is likely to identify virtually all sources that could provide visibility benefits when their emissions are controlled.

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

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

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Merrimack Station Unit MK2, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

PSNH currently operates an SCR system on Unit MK2. This system was installed in 1994 to meet the requirements of NO_X RACT and the ozone season NO_X budget program. SNCR is the only other control technology available for controlling NO_X emissions from this unit. SCR yields higher NO_X removal rates and is more cost-effective than SNCR. For units that already have seasonally operated SCRs, year-round operation is EPA's presumptive norm for BART. PSNH estimated, in 1998, that the existing SCR system could be operated year-round at a cost of $494 per ton of NO_X removed.

For an early-generation SCR that has received previous retrofits to improve its performance, further upgrades to this NO_X control system appear to be impractical and would yield negligible (generally less than 0.1 dv) improvement in visibility. Additional upgrades would require major redesign and construction at a location where physical space is already constrained. Capital costs would be comparable to installing a new SCR and would achieve only marginal additional reductions in NO_X emissions. Because Unit MK2 has an existing SCR system designed to meet other air program requirements that could be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on this unit.

EPA has provided presumptive BART emission rates that are broadly applicable to power plants larger than 750 MW but are not necessarily representative of smaller EGUs like Unit MK2. In the case of Unit MK2, the cyclone boiler has a relatively high uncontrolled NO_X emission rate ($\geq$2.0 lb/MMBtu); so it follows that the controlled emission rate, even at 90 percent control efficiency, would be above the presumptive norm of 0.10 lb/MMBtu applicable to larger EGUs of its type. The past decade of emissions records for Unit MK2 shows monthly average NO_X emission rates normally ranging between 50 and 100 percent of the RACT limit. The existing NO_X RACT limit of 15.4 ton/day, equivalent to of 0.37 lb/MMBtu*, corresponds to a NO_X control rate of approximately 85 percent.

PSNH has described operational and infrastructural changes that would be needed in order to allow the company to guarantee a NO_X performance level lower than the current effective limit of 0.37 lb/MMBtu (see Supporting Documentation, attached). This could be accomplished by increasing the frequency of maintenance cleanings and accelerating the rate of catalyst replacement to ensure a high level of NOx reduction capability at all times. The four major cost components would be:

1. The direct costs of extra inspections and maintenance cleanings for the air heater and SCR system,
2. The cost of purchased replacement power covering the periods of additional scheduled maintenance outages,
3. The cost of extra catalyst (early catalyst replacement), and
4. The increased cost of purchased replacement power associated with reduced flexibility to operate at partial load.

Calculations performed by PSNH assume a NOx emission rate of 0.8 lb/MMBtu during partial load operation. This relatively high emission rate means that, the lower the emission limit is set, the smaller must be the total time of partial load operation as a percentage of total operating time. As the emission limit is set lower, outage time would necessarily have to increase to prevent excessive emissions (that would otherwise occur under partial load operation). Replacement power at such times would represent an unavoidable cost.

Taking into account all of the described cost factors, PSNH has estimated that a reduction in the NO_X emission limit to 0.30 lb/MMBtu (an effective reduction of 0.07 lb/MMBtu) would have an incremental cost of approximately $800 per ton of NO_X removed and would result in a *potential* incremental emission reduction of about 1,000 tons per year. The indicated cost per ton falls within the generally regarded cost-effective range. At the same time, PSNH has estimated that further reduction of the NOx emission limit to 0.25-0.30 lb/MMBtu would yield diminishing returns, with the incremental cost per ton approximately one order of magnitude higher. NHDES concurs that such additional costs are not justifiable given the fact of negligible visibility benefit. When the historical performance of Unit MK2 is considered alongside the operational factors and estimated costs to achieve a higher performance level, NHDES finds that a NO_X emission rate of 0.30 lb/MMBtu reasonably represents the sustainable performance capabilities of this unit and is also appropriate as a BART control level for NO_X on a 30-day rolling average basis.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates two ESPs in series on Unit MK2. Mechanical collectors (cyclones) are effective only for coarse particle removal and would be impractical as a retrofit for Unit MK2, where the more efficient ESPs already exist. Fabric filters have performance levels

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* The 0.37 lb/MMBtu NO_X emission rate for MK2 is calculated from its maximum heat input rate of 3,473 MMBtu/hr and the applicable NO_X RACT limit of 15.4 tons per day, as follows:

$[(15.4 \text{ tons/day} \times 1 \text{ day/24 hr}) \times 2{,}000 \text{ lb/ton}] \div 3{,}473 \text{ MMBtu/hr} = 0.37 \text{ lb/MMBtu}$

comparable to ESPs and are a suitable PM control technology for power plant emissions. However, fabric filters are also impractical as a retrofit for Unit MK2 under present circumstances: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress.

The existing ESPs were previously upgraded to include state-of-the-art electronic controls. Further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of the aforementioned spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of \$10,000 to \$30,000 per MW. For Unit MK2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.1 dv on the 20 percent worst visibility days) that would be realized.

The current PM emission limit for Unit MK2 is not reflective of the performance capabilities of the existing ESPs. However, the volume of available stack test data is insufficient to establish a conclusive, long-term BART performance level of 0.04 lb/MMBtu or lower for this unit. New Hampshire has adopted a new administrative rule that will hold TSP emissions to a maximum of 0.08 lb/MMBtu but will apply this limitation more broadly than BART requires. The new PM emission limit will affect both of Merrimack Station's coal-fired utility boilers – Unit MK1 (not a BART-eligible facility) and Unit MK2 – as explained below.

In the new rule, Units MK1 and MK2 are placed within a regulatory "bubble" for the purposes of TSP compliance. This arrangement serves both necessity and convenience because the two units will share a common stack. The following procedure was used to calculate the maximum allowable emission rate for the combined source:

1. For BART-eligible Unit MK2, the maximum heat input rating of 3,473 MMBtu/hr was multiplied by MANE-VU's lowest presumptive control level for TSP emissions, 0.02 lb/MMBtu, to obtain an emission rate of 69.46 lb/hr.

2. For non-BART Unit MK1, the maximum heat input rating of 1,238 MMBtu/hr was multiplied by the unit's permitted TSP limit, 0.27 lb/MMBtu, to determine an emission rate of 334.26 lb/hr.

3. The individual emission rates were summed to yield a total maximum emission rate of 403.72 lb/hr. This value was divided by the total maximum heat input rate, 4,711 MMBtu/hr, to obtain the new TSP emission limitation of 0.08 lb/MMBtu (rounded down from 0.086 lb/MMBtu).

By including Unit MK1 in the rule, the allowable TSP emissions from the two coal-fired units combined will be less than the allowable emissions would be if the limit for Unit MK1 remained separate and unchanged, and the limit for Unit MK2 were reduced to 0.04 lb/MMBtu, its approximate performance capability from actual stack test data.[†]

[†] For the bubble concept, the combined emission rate = 0.08 lb/MMBtu × 4,711MMBtu/hr = <u>377 lb/hr</u>. For the stand-alone alternative, the sum of the individual emission rates = (0.04 lb/MMBtu × 3,473 MMBtu/hr) + (0.27 lb/MMBtu × 1,238 MMBtu/hr) = <u>473 lb/hr</u>.

It is concluded that the existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Continued operation of the existing ESPs, controlled to emission rates not exceeding the new emission limit described above, represents BART for PM control on Unit MK2.

6.3 Selecting a Pollution Control Plan for SO_2

PSNH Merrimack Station is installing a flue gas desulfurization system to remove mercury emissions in compliance with New Hampshire law. As a co-benefit, the FGD system is expected to remove more than 90 percent of SO_2 emissions. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (generally applicable to facilities larger than Merrimack Station), the FGD system is considered to be BART for SO_2 control on Unit MK2. (Note that, at an installed cost exceeding $1,000/kW, the FGD system being added to this facility is more expensive than the industry average and might not be viewed as cost-effective if its only purpose were to satisfy BART requirements.)

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Merrimack Station Unit MK2 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to meet or exceed BART requirements as well as changes in progress that are consistent with BART requirements. NHDES has already issued a temporary permit (construction permit) for the installation of the flue gas desulfurization system and is not requiring additional control technology for Merrimack Station at this time in order to comply with BART.

Table 7-1. Summary of BART Determinations for Unit MK2

Pollutant	Current Emission Controls	Additional Emission Controls in Progress	BART Controls	BART Emission Limit
NO_X	SCR	None	SCR	0.30 lb/MMBtu, 30-day rolling average
PM	Two ESPs in series	None	Two ESPs in series	0.08 lb/MMBtu total suspended particulate (TSP)
SO_2	Fuel sulfur limits set at 2.0 lb sulfur/MMBtu (averaged over 3 mos.) and 2.8 lb sulfur/MMBtu at any time	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis; existing fuel sulfur limits to remain in effect	10% of uncontrolled SO_2 emissions, calendar monthly average

NEW HAMPSHIRE BART ANALYSIS: Merrimack Station Unit MK2 (320 MW)

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[7]						
							Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref.
NO_X	SCR (existing)	85%	19,140 [1]	2,871 [2]	16,269		37,710,186	118	1,910,432	5,069,414	312	8
	SNCR	45%	19,140 [1]	10,527	8,613		3,876,771	12	4,781,136	5,105,893	593	8
PM	2 ESPs (existing)	99+%	30,060 [2]	210 [2]	29,850	min.	23,280,363	73	1,086,417	2,571,006	86	9
						max.	62,080,967	194	1,940,030	7,140,553	239	
	Fabric Filters	99%	30,060 [2]	301	29,759	min.	18,624,290	58	2,172,834	3,732,991	125	9
						max.	62,080,967	194	3,104,048	8,304,571	279	
SO_2	Lower-S coal (existing)	40% [3]	—	—	—		—	—	—	—	—	
	FGD	90% [4]	20,902 [5]	2,090	18,812 [6]		457,000,000	1,055	unknown	unknown	unknown	10

[1] Estimated.

[2] 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

[3] Estimated average reduction in fuel sulfur content with use of lower-S coal, resulting in equivalent reduction in SO_2 emissions.

[4] Additional control level on emissions after existing controls have been applied; overall control level with use of lower-S coal is estimated to be 40 + 90(1 - 0.40) = 94%

[5] 2002 (baseline) emissions with use of lower-sulfur coal at ~1.0 % S by weight.

[6] Reductions from baseline emissions.

[7] All cost estimates adjusted to 2008$.

[8] USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

[9] NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

[10] FGD capital cost is PSNH's estimate (2008$) for Units MK1 (113 MW) and MK2 (320 MW) combined.

Merrimack Station Unit MK2: NO$_X$ Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Generation capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	111.48	103.46	33,108,152	2,773,470	0.74	0.69	219,771	0.67	0.65	1,457,518	1,677,289	4,450,759	16,269	274
SNCR	11.04	10.64	3,403,662	285,125	0.16	0.15	49,328	1.46	1.85	4,148,332	4,197,661	4,482,786	8,613	520

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	126.98	117.84	37,710,186	3,158,982	0.84	0.78	250,319	0.76	0.74	1,660,113	1,910,432	5,069,414	16,269	312
SNCR	12.57	12.11	3,876,771	324,757	0.18	0.18	56,185	1.66	2.11	4,724,951	4,781,136	5,105,893	8,613	593

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Merrimack Station Unit MK2: PM Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr
Flue gas flow rate	1,362,620	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	20,439,300	1,712,200	0.25	0.45	953,834	2,666,034	29,850	89
	max.	40.00	54,504,800	4,565,867	0.65	0.60	1,703,275	6,269,142	29,850	210
Wet ESP	min.	15.00	20,439,300	1,712,200	0.15	0.25	545,048	2,257,248	29,850	76
	max.	40.00	54,504,800	4,565,867	0.50	0.50	1,362,620	5,928,487	29,850	199
Fabric Filter - Reverse Air	min.	17.00	23,164,540	1,940,494	0.35	0.70	1,430,751	3,371,245	29,759	113
	max.	40.00	54,504,800	4,565,867	0.75	0.80	2,112,061	6,677,928	29,759	224
Fabric Filter - Pulse Jet	min.	12.00	16,351,440	1,369,760	0.50	0.90	1,907,668	3,277,428	29,759	110
	max.	40.00	54,504,800	4,565,867	0.90	1.10	2,725,240	7,291,107	29,759	245

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	23,280,363	1,950,196	0.28	0.51	1,086,417	3,036,613	29,850	102
	max.	45.56	62,080,967	5,200,523	0.74	0.68	1,940,030	7,140,553	29,850	239
Wet ESP	min.	17.09	23,280,363	1,950,196	0.17	0.28	620,810	2,571,006	29,850	86
	max.	45.56	62,080,967	5,200,523	0.57	0.57	1,552,024	6,752,547	29,850	226
Fabric Filter - Reverse Air	min.	19.36	26,384,411	2,210,222	0.40	0.80	1,629,625	3,839,848	29,759	129
	max.	45.56	62,080,967	5,200,523	0.85	0.91	2,405,637	7,606,160	29,759	256
Fabric Filter - Pulse Jet	min.	13.67	18,624,290	1,560,157	0.57	1.03	2,172,834	3,732,991	29,759	125
	max.	45.56	62,080,967	5,200,523	1.03	1.25	3,104,048	8,304,571	29,759	279

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BART Analysis for PSNH Newington Station Unit NT1

January 14, 2011
Amended August 26, 2011

BART Analysis for
PSNH Newington Station Unit NT1

1. INTRODUCTION

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

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

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

Combustion Controls

Controls on the combustion process can reduce NO_X formation by as much 75 percent. Combustion controls or firing practices include such measures as staged combustion, limiting excess air, providing overfire air, recirculating the flue gases, using low-NO_X burners, and injecting water or steam.

Operating with low excess air involves restricting the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compatible boiler operation. Because less oxygen is introduced into the combustion zone, NO_X formation is inhibited. Adjustments to the air supply may affect normal boiler operation and may reduce operational flexibility. The effectiveness of limiting excess air varies from boiler to boiler, but typical NO_X reductions are 10 to 25 percent from uncontrolled levels.

Overfire air (OFA) is a method where some of the total combustion air is diverted from the burners and injected through ports above the top burner level. This staged combustion reduces fuel-based NO_X formation in the oxygen-deficient primary combustion zone and limits thermal NO_X formation because of the lower peak flame temperature (i.e., combustion occurs over a larger portion of the furnace). For oil-fired boilers, OFA typically reduces NO_X emissions by 15 to 45 percent.

Flue gas recirculation (FGR) involves reinjecting a portion of the cooled flue gas into the combustion chamber. FGR dilutes the oxygen concentration in the combustion zone and depresses peak flame temperature by adding a large amount of cooled gas to the fuel-air mixture, resulting in less thermal NO_X formation. FGR reduces NO_X emissions by about 40 to 60 percent in oil-fired boilers.

Low-NO_X burners (LNB) are designed to control fuel/air mixing and increase heat dissipation. These alternative burners can be installed on new boilers or retrofitted on older units. LNB technology integrates staged combustion in the burner. A typical LNB creates a fuel-rich primary combustion zone, thus lowering the formation of fuel-based NO_X. At the same time, limited combustion air reduces the flame temperature, minimizing the formation of thermal NO_X. Combustion is completed in a lower-temperature, fuel-lean zone. LNB retrofits have been shown to reduce NO_X formation by 30 to 55 percent.

Water or steam can be injected into the boiler combustion zone to reduce the peak flame temperature, with a corresponding reduction in thermal NO_X formation. Water/steam injection can reduce NO_X emissions by as much as 75 percent in gas-fired boilers and slightly less in oil-fired boilers.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) There is limited commercial experience with SNCR from which to judge its effectiveness for oil-fired boilers. NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on some oil-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S. Although there is little experience with SCR systems on oil-fired boilers, SCR retrofits for oil-fired EGUs using the latest technology would be expected to achieve NO_X control efficiencies toward the upper end of this range.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls at Newington Station Unit NT1 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit

(EGU) the size of Unit NT1. For low-NO_X burners, the total annual cost is estimated to be about $830,000, or $1,470 per ton of NO_X removed. With the addition of overfire air, this cost rises to $1,130,000, or $1,600 per ton. For SNCR, the total annual cost is estimated to be $730,000, or $1,030 per ton. For SCR, the total annual cost doubles to $1,410,000; but the unit cost is only moderately higher at $1,180 per ton of NO_X removed. Because Unit NT1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
LNB	21.9	7,900,000	170,000	830,000	1,470
LNB+OFA	29.8	10,700,000	230,000	1,130,000	1,600
SNCR	12.3	3,300,000	450,000	730,000	1,030
SCR	36.7	11,500,000	440,000	1,410,000	1,180

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and 701million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on the following estimates of NO_X removed: 563 tons for LNB; 704 tons for LNB+OFA; 704 tons for SNCR; and 1,196 tons for SCR.

Low-NO_X burners have previously been reported to operate in a cost range of $200 to $500 per ton of NO_X removed (NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005); however, this cost range is likely to be more relevant to larger plants operating at higher capacity factors than Newington Station.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome extra pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy.

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

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

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag. The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit NT1. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	29.3-78.1 million	1.4-2.4 million	3.8-9.0 million	27,000-63,000
Wet ESP	73-194	29.3-78.1 million	0.8-2.0 million	3.2-8.5 million	23,000-60,000
Fabric filter – reverse air	82-194	33.2-78.1 million	2.0-3.0 million	4.8-9.6 million	14,000-29,000
Fabric filter – pulse jet	58-194	23.4-78.1 million	2.7-3.9 million	4.7-10.4 million	14,000-31,000

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. (Note that these costs were developed for coal-fired boilers.) All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and flue gas flow rate of 1.71 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 142 tons of PM removed for ESPs and 335 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $3.2 million to $10.4 million, or $14,000 to $63,000 per ton of PM removed. Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of $10,000 to $30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit NT1 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule). While experience with FGD systems on smaller, oil-fired EGUs is generally lacking, it is anticipated that such installations would perform at a similar level, achieving SO_2 removal efficiencies of 90 percent or greater.

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Fuels

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. For facilities that burn fuel oil, switching to a lower-sulfur fuel may be a cost-effective control option. Switching from high-sulfur residual fuel oil to low-sulfur residual fuel oil or low-sulfur distillate fuel oil is one possible control strategy. For facilities that have the option to replace fuel oil with natural gas or can co-fire with natural gas, increasing the use of natural gas is another effective control strategy. Sulfur dioxide emissions from burning natural gas are negligible in comparison to those from burning fuel oil. When substituting natural gas for fuel oil, the resulting SO_2 emission reductions are roughly proportional to the fraction of natural gas burned on a Btu-equivalent basis.

2.3.1 Potential Costs of SO_2 Controls

There is little or no experience with, or cost data on, flue gas desulfurization at oil-fired power plants. However, the technology is similar to FGD for coal-fired plants. Therefore, the costs of an FGD system for PSNH Newington Station may be crudely approximated by extrapolating from the costs of FGD for PSNH Merrimack Station.

The flue gas desulfurization system at Merrimack Station is being installed to reduce mercury emissions (with SO_2 removal as a co-benefit) at its two coal-fired boilers. These units have a combined generating capacity of 433 MW, or slightly greater than the capacity of Newington Station Unit NT1. The company's capital cost estimate for the wet limestone FGD system is $457 million, or $1,055/kW (both amounts in 2008$), which is said to be in line with project costs for multiple-unit scrubber installations occurring elsewhere in the United States. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

Using the latest Merrimack Station estimate of $1,055/kW for scaling purposes, the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about *twice* the cost of FGD on coal-fired boilers of comparable size (NESCAUM, 2005).

The costs of switching to a low-sulfur fuel oil at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur product at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately $3.3 million per year, or $1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately $6.6 million per year, or also $1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2009 has been below 2002 levels). These results imply that the costs of switching fuel oils may be relatively constant on a $/ton basis as long as supplies are adequate.

Table 2-3 summarizes the approximate costs of flue gas desulfurization and fuel switching as SO_2 control options for PSNH Newington Station Unit NT1. The costs for switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil are listed. At any given time, the actual cost of fuel switching would vary in proportion to the applicable fuel price differential.

Table 2-3. SO_2 Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
FGD	1,055	422,000,000	unknown	unknown	unknown
Switch to 1.0%-S oil	—	—	3,300,000	3,300,000	$1,900
Switch to 0.5%-S oil	—	—	6,600,000	6,600,000	$1,900

Capital cost estimate for FGD is based on reported cost per kilowatt-hour for FGD system at PSNH Merrimack Station. Actual costs for Newington Station could be much higher. O&M costs for fuel switching are based on 2002 annual fuel usage of 44,140,000 gallons and estimated fuel price differential of 7.5 or 15 ¢/gallon for substitution of 1.0%-S or 0.5%-S residual fuel oil, respectively.

In a similar analysis performed independently by PSNH (see attached letter), the company has estimated the costs of fuel switching based on historical fuel prices for the period 2002-2009 as compiled by Platts[‡]. Table 2-4 reproduces the fuel oil prices used by PSNH:

Table 2-4. Historical Fuel Oil Prices, 2002-2009 ($/barrel)

Year	2%S Oil	1%S Oil	0.7%S Oil	0.5%S Oil	0.3%S Oil
2002	21.20	22.45	23.26	23.80	25.25
2003	24.95	27.48	29.26	30.45	32.63
2004	25.25	27.92	30.04	31.46	34.53
2005	37.00	41.00	44.00	46.00	50.10
2006	45.50	46.30	48.46	49.90	54.12
2007	53.70	53.45	56.54	58.60	62.86
2008	75.25	77.80	81.10	83.30	92.16
2009	49.90	50.75	51.98	52.80	55.83

Source: Platts. 2009 data include costs through 9/09.

[‡] Platts, a division of The McGraw-Hill Companies, is a provider of energy information services.

Using this historical fuel price record and PSNH's calculated SO_2 emission reductions from fuel switching, the New Hampshire Department of Environmental Services (NHDES) has prepared alternate estimates of the increased costs of fuel switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil, and other variations, in Table 2-5. Costs are listed in terms of $/barrel, $/hour, and $/ton. This analysis produces somewhat less conservative (lower) estimates of the cost of fuel switching than the $1,900/ton estimate given above. In either analysis, the cost-effectiveness of switching to 0.5%-sulfur residual fuel oil appears reasonable as long as supplies remain stable. Switching to 0.3%-sulfur fuel oil could also prove reasonable in the future if prices were to stay within their recent historical range and future supplies could be assured.

Table 2-5. Costs of Fuel Switching Based on Historical Fuel Oil Prices

Fuel Switch	SO_2 Emission Reduction* (lb/hr)	Increased Cost ($/barrel)		Increased Cost ($/hour)**		$/ton of SO_2 Removed***	
		low	high	low	high	low	high
→ 2% to 1%	***5,228.7***	***0***	***4***	***0***	***2,692***	***0***	***1,030***
1% to 0.7%	1,470.3	1	3.3	673	2,222	414	3,022
0.7% to 0.5%	957.0	1	2.2	673	1,482	586	3,095
0.5% to 0.3%	935.3	3	9	2,020	6,059	2,967	12,957
2% to 0.7%	6,699.0	2	7	1,34	4,712	402	1,407
→ 2% to 0.5%	***7,656.0***	***3***	***9***	***2,019***	***6,058***	***528***	***1,583***
2% to 0.3%	8,591.3	4	17	2,692	11,444	627	2,664

* Calculated reduction, from PSNH letter dated December 4, 2009.

** $/barrel ÷ 42 gal/barrel ÷ 0.153846 MMBtu/gal × MMBtu/hr = $/hr

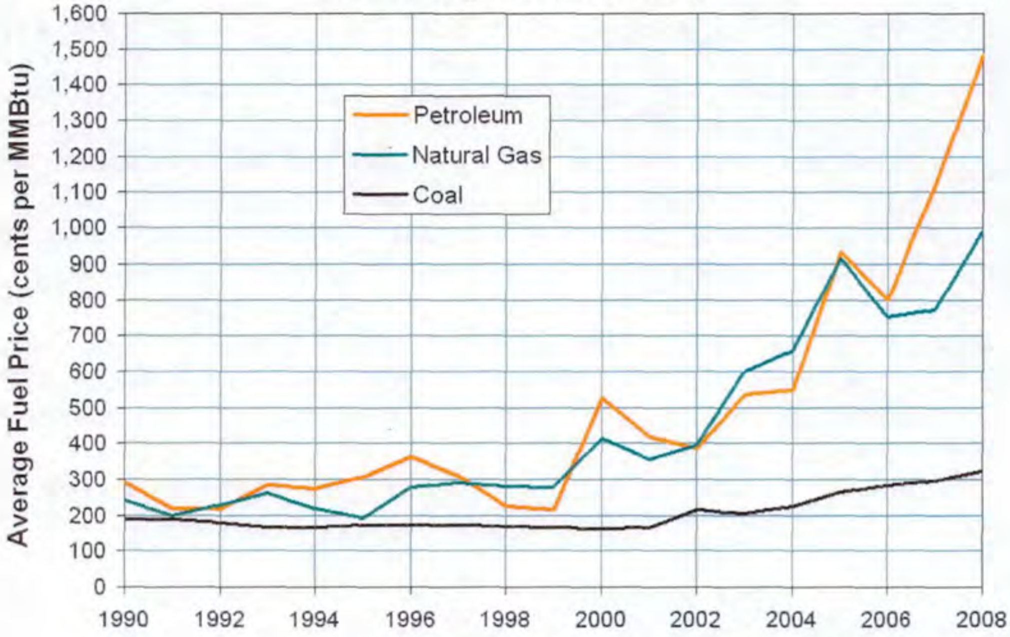
*** $/hr ÷ lb/hr × 2000 lb/ton = $/ton

Besides switching residual fuel oils to reduce SO_2 emissions, other proposed options include replacing 2.0%-S residual fuel oil with low-sulfur distillate fuel oil or natural gas. Although distillate fuel oil is sometimes used during startup of Unit NT1, the boiler is not designed to operate routinely on this fuel; and retrofitting the boiler for this purpose would involve major capital expenditure. Burner replacements to combust distillate fuel oil could exceed $20 to $30 million (approximately $1 to 2 million per burner) in direct capital costs, not including the additional costs of engineering and any required auxiliary equipment.

The cost determinations associated with using natural gas are more complicated. Unit NT1 can be fired with either natural gas or liquid fuel (i.e., residual fuel oil or biofuel), or it can be co-fired with both types of fuel at the same time. However, because of physical limitations to the boiler's design, the unit cannot operate at full capacity when fueled solely by natural gas. In order to reach maximum heat input, the boiler must either use liquid fuel or be co-fired with both fuel types. (Unit NT1 can operate at up to about 50 percent of maximum heat input from natural gas, with no corresponding limitation on liquid fuel.) Firing Unit NT1 entirely with natural gas might be technically feasible but would require more than just burner replacements: it would require modifications to other major boiler components or replacement of the entire boiler. Such measures cannot be economically justified. However, using natural gas – to the extent that Unit NT1 can burn this fuel with existing equipment – remains a viable option as long as the cost of this fuel is competitive with the cost of residual fuel oil and biofuel.

Volatile energy commodity prices in recent years and the uncertainty of future fuel prices make it difficult to provide a useful estimate of the cost of substituting natural gas for residual fuel oil. As seen in Figure 2-1, past prices of natural gas and petroleum fuels, on a BTU-equivalent basis, exhibit similar trends; but the price differentials show wide variation from year to year. Consequently, no cost estimate for this fuel switching option is presented.

Figure 2-1. Comparison of Fossil Fuel Prices for Electric Generation in New England (1990-2008)



Data source: Energy Information Administration, Form EIA-923, "Power Plant Operations Report."
http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

PSNH Newington Station Unit NT1 currently operates with low-NOx burners, an overfire air system, and water injection to minimize NO_X formation. For compliance with NO_X RACT requirements, the facility's existing air permit limits NO_X emissions from this unit to a daily average of 0.35 lb/MMBtu when burning oil and 0.25 lb/MMBtu when burning a combination of oil and gas. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NO_X emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NO_X RACT limits. Actual NO_X emissions from this unit were 943 tons in 2002.

3.2 Discussion of Current PM Emissions and Controls

Unit NT1 has an electrostatic precipitator to capture PM emissions. In an EPA inspection report on this unit from December 15, 1989, a table of design values for the ESP listed a particulate removal efficiency of 93 percent. It is unknown whether the stated efficiency is representative of actual long-term performance. The facility's air permit (TV-OP-054, March 9, 2007; administrative amendment, December 17, 2007) sets an emission limit of 0.22 lb/MMBtu total suspended particulate matter (filterable TSP). The single available stack test on Unit NT1 measured a controlled TSP emission rate of 0.058 lb/MMBtu, which is well below the permit limit. The tested emission rate lies within the expected range for a properly operating ESP at a plant like Newington and may serve as a better measure of performance than any stated efficiency for this control device. Actual TSP emissions from Unit NT1 were 198 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

Sulfur dioxide emissions are partially controlled at PSNH Newington Station by existing limits on fuel oil sulfur content. Permitted fuel sulfur limits are 2.0% sulfur by weight for No. 6 fuel oil and 0.4% sulfur by weight for No. 2 fuel oil. Unit NT1 does not have an individual limitation on sulfur dioxide emissions but is subject to an annual cap of 55,150 tons of SO_2 for all electrical generating units at PSNH's Merrimack, Newington, and Schiller Stations combined. Actual SO_2 emissions from Unit NT1 were 5,226 tons in 2002. The average sulfur content of No. 6 fuel oil burned that year was 1.2% by weight, which is typical of values from the most recent decade. In 2009, the average was 1.0%.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Newington Station Unit NT1 was built in 1969. However, because this facility runs primarily on fuel oil, its remaining useful life may depend more on future commodity supplies/prices and other external factors than on the longevity of plant equipment.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

NHDES performed a set of CALPUFF model runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. The same methodologies used for the CALPUFF modeling work for Merrimack Station Unit MK2 were applied to the modeling for Newington Station Unit NT1.

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit NT1 produce theoretical CALPUFF worst-case impacts of 1.22 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit NT1 exceed all of these exemption levels. The CALPUFF-predicted visibility benefits from BART controls on 20% worst natural and 20% worst baseline visibility days are presented in Table 5-1.

As seen in the table, more benefit would result generally from SO_2 emission reductions than NOx emission reductions. This finding reinforces MANE-VU's early determination that SO_2 was the primary target pollutant for maximizing visibility improvements. NO_X, while also an important visibility impairing pollutant, reacts with ammonia less preferentially than does SO_2 and is also less hydrophilic than SO_2. As a result, NO_X has a lower rate of formation of haze-causing particles and impairs visibility less effectively than a similar mass of SO_2.

Table 5-1. CALPUFF Modeling Results for Newington Station Unit NT1:
Visibility Improvements from BART Controls

On the 20% Worst Natural Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	0.57	0.45	**0.09**
	1.0%-S residual fuel oil (50% sulfur reduction*)	0.30	0.24	**0.05**
	0.5%-S residual fuel oil (75% sulfur reduction*)	0.46	0.36	**0.07**
	0.3%-S residual fuel oil (85% sulfur reduction*)	0.52	0.40	**0.08**
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	0.47	0.37	**0.08**
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	*<0.05*	*0.03*	_**<0.01**_***
NOx	SNCR (25% NOx reduction**)	0.11	0.10	**0.04**
	SCR (78% NOx reduction**)	0.34	0.30	**0.12**
PM	Baghouse (85% PM reduction**)	0.05	0.04	**0.01**

On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	**0.13**	**0.10**	<0.01***
	1.0%-S residual fuel oil (50% sulfur reduction*)	**0.07**	**0.06**	<0.01***
	0.5%-S residual fuel oil (75% sulfur reduction*)	**0.11**	**0.09**	0.01
	0.3%-S residual fuel oil (85% sulfur reduction*)	**0.13**	**0.10**	0.01
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	**0.11**	**0.09**	0.01
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	_**0.01**_	_**0.01**_	*<0.01****
NOx	SNCR (25% NOx reduction**)	**0.04**	**0.03**	0.01
	SCR (78% NOx reduction**)	**0.11**	**0.10**	0.03
PM	Baghouse (85% PM reduction**)	**0.02**	**0.02**	<0.01***

* from maximum permitted level

** from baseline level with existing controls

*** below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of switching to lower-sulfur fuel for this unit. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline.

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, switching to lower-sulfur fuel oil for Unit NT1 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by about 1.4 $\mu g/m^3$. Reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement at the affected Class I areas.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Newington Station Unit NT1, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

Use of low excess air reduces NO_X emissions but can often result in greater PM and/or CO emissions. Many of the NO_X reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of low-NOx burners, overfire air, and water injection; so the application of low excess air would be redundant in this case. Flue gas recirculation reduces the peak flame temperature in much the same way as overfire air and has the additional benefit of reducing the oxygen content in the combustion zone, leading to further reductions in NO_X formation. Because Unit NT1 operates with an existing overfire air system, and because this boiler has already been modified by the installation of natural gas lances, FGR is economically impractical and might also be physically infeasible.

The NO_X emission reductions being achieved at Unit NT1 through the use of combustion control technologies are a substantial improvement over no controls. Retrofitting the facility with SCR or SNCR would reduce NO_X emissions by an additional 300 to 700 tons per year. Despite the sizeable emission reductions that SCR or SNCR would provide, with annualized costs of \$0.7 to \$1.3 million, neither technology option could be implemented cost-effectively. Note that these dollar amounts do not include the significant additional costs of redesigning Newington Station's layout to address spatial constraints. Also, the estimated costs are based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-

2009, it is difficult to justify additional technology retrofits to reduce NO_X emissions at this facility today. This conclusion is reinforced by the small improvement in visibility that might be obtained with such retrofits on the few occasions when meteorological conditions would indicate maximum impacts.

Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NT1 and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment. However, the issue is not so much the magnitude of ammonia slip, toxicity, or visibility impairment as the fact that ammonia slip would occur at all. On balance, this is a relatively minor negative to be weighed in the context of other factors.

Based on all of these considerations, NHDES finds that SCR and SNCR are not cost-effective as Best Available Retrofit Technology for NO_X control at this facility and will not be evaluated further. The existing NO_X controls, which include low-NOx burners, overfire air, and water injection, are determined to fulfill BART requirements for Newington Station Unit NT1.

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

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Although it may be technically feasible to improve performance of the existing ESP through some form of upgrade, it is difficult to justify any major capital expense at this facility in light of its recent operating history. Since 2006, the plant's capacity factor has been below 10 percent. In consideration of the facts that Unit NT1 already operates a fully functional ESP, that additional capital outlay for PM control cannot be economically justified at this time, and that any resulting benefit to visibility would be negligible, it is determined that the existing ESP fulfills BART requirements.

The single available stack test on this unit indicates that the ESP yields controlled TSP emission rates in the vicinity of 0.06 lb/MMBtu versus a currently permitted rate of 0.22 lb/MMBtu. The extent of the data record is insufficient to support consideration of a BART performance level more restrictive than the existing permit limit. The facility's Title V operating permit requires that a compliance stack test for PM emissions be performed on Unit NT1 before the permit expires on March 31, 2012. NHDES will review the stack test results to ascertain the unit's performance and incorporate any new limit into a permit amendment by the permit expiration date, as appropriate. The permit expiration date precedes the effective date of proposed BART control measures by fifteen months.

6.3 Selecting a Pollution Control Plan for SO_2

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

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

When not firing exclusively on natural gas, Newington Station Unit NT1 has traditionally burned No. 6 fuel residual fuel oil at 2.0 percent (nominal) sulfur content. From 2002 to 2009, the actual average annual sulfur content of the fuel oil ranged between 1.03 and 1.54 percent by weight, with no significant trend (average fuel sulfur content was 1.21 percent in 2002). For New Hampshire's BART analysis of this plant, the following fuel sulfur values were assumed:

Nominal %S (permit limitation)	Assumed Actual %S (chemical assay)
2.0	1.2
1.0	0.8
0.5	0.4

Under these assumptions, switching from 2.0 %S (nominal) to 1.0 %S (nominal) residual fuel oil would produce a one-third reduction in sulfur dioxide emissions, and switching to 0.5 %S (nominal) residual fuel oil would produce a two-thirds reduction in sulfur dioxide emissions at this facility.

The proposed fuel switching could be accomplished without capital expense and would have predictable costs tied directly to fuel consumption and fuel price differentials. The cost per ton would be no more than about $1,900 (historical fuel prices suggest a range of $0 to $2,000 per ton). At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008$) for switching to 1.0% or 0.5% residual fuel oil would be about $3.3 or $6.6 million (equivalent to $0.0047 or $0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

While fuel availability is always a consideration, supplies should not be a significant factor in obtaining fuels whose sulfur content is as low as 0.5 percent. Residual fuel oil at 1.0% sulfur is already widely distributed within the region; and there is greater assurance today of the availability 0.5%-sulfur residual fuel oil than in 2008, when New Hampshire began

drafting its BART determinations. Maine, Massachusetts, New Jersey, and other states within MANE-VU are moving toward or already require the use of 0.5%-sulfur residual fuel oil, thus ensuring the presence of a regional market for this commodity.
NHDES considered the possible use of 0.3%-sulfur residual fuel oil for Unit NT1; but this fuel has had only very limited use within the northern New England region, and its future availability and price remain uncertain. More specifically, the fact that some plants in Connecticut are using 0.3%-sulfur residual fuel oil today does not guarantee the availability of this fuel in northern New England, which obtains its bulk oil shipments through different ports.

For Unit NT1, the possible use of low-sulfur residual fuel oil is complicated by the plant's low capacity factor and existing fuel stocks and storage facilities. The plant now has a sizeable quantity of higher-sulfur residual fuel oil in storage tanks on site. Because there is no practical way to offload and replace the existing inventory with a lower-sulfur residual fuel oil, the existing stock of higher-sulfur fuel oil would have to be used up before requiring that Unit NT1 be fired exclusively with low-sulfur fuel oil. Also, it is anticipated that the plant will continue to have a low utilization rate and capacity factor in the coming years (its capacity factor was less than 7 percent in 2009). Given this scenario, depletion of the existing stock of residual fuel oil could take more than a year, or substantially longer if the facility co-fires with natural gas to reduce sulfur dioxide emissions.

EPA has suggested greater use of natural gas and/or low-sulfur distillate fuel oil for Unit NT1 in place of residual fuel oil. The substitution of No. 2 distillate fuel oil for No. 6 residual fuel oil would not be practical for this facility for two major reasons: the high cost of burner replacements needed to implement this option, and the plant's low utilization rate and capacity factor. Unit NT1 would produce relatively few kilowatt-hours of generation through which to recover capital costs.

Greater use of natural gas is a reasonable option when its price is competitive with that of residual fuel oil. Recent years have witnessed sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. While the future price and availability of natural gas remain difficult to discern, the market for natural gas is expected to expand amid global concerns about carbon emissions and a visible renaissance in gas exploration and development.

Unit NT1 has considerable operational flexibility with respect to fuel selection. The boiler can be fired with either natural gas or liquid fuel as the only fuel, or it can be co-fired with both fuel types simultaneously. However, because of physical limitations to the boiler's design, the unit can operate at no more than about 50 percent of maximum heat input when fueled solely by natural gas. There is already a natural incentive for PSNH to operate Unit NT1 with natural gas as much as possible whenever the price of this fuel is competitive with or less than the price of liquid fuels.

In recognition of the dual-fuel capability of Unit NT1, NHDES has developed for this facility a requirement by rule establishing a new sulfur dioxide emission limitation of 0.50 lb/MMBtu[§] applicable to any fuel type or mix. The recently adopted rule (Attachment GG)

[§] This limit is calculated using USEPA's published AP-42 emission factor for SO_2 of 150(S) lb SO_2/1000 gallons. Assuming 0.5% fuel sulfur content by weight and a heating value of 150,000 Btu/gallon for No. 6 fuel oil, the SO_2 emission rate would be $150 \times 0.5 = 0.075$ lb/gallon, and the SO_2 emission factor would be 0.075

will allow the facility the flexibility to burn natural gas and/or fuel oil in any feasible ratio, depending on market conditions.

New Hampshire's new rule will cause a substantial reduction in SO_2 emissions from Unit NT1 regardless of fuel type while rendering unnecessary any need to speculate on the direction of relative fuel supplies and prices. For the first regional haze progress report, due no later than December 17, 2012, NHDES will review fuel usage, fuel supplies, fuel prices, and plant utilization/capacity factors to determine whether the fuel sulfur limitation described above is still appropriate as BART control for Unit NT1. Should the review indicate a different BART control level, the facility's Title V operating permit will be amended as necessary before its expiration date of March 31, 2012, fifteen months prior to the effective date of proposed BART control measures. The use of low- or ultra-low-sulfur residual fuel oil will be reconsidered as part of this review. Looking beyond 2012, a possible further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all residual fuel oils throughout the region by 2018 (refer to "Statement of the Mid-Atlantic/ Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," June 20, 2007, included in Attachment E).

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Newington Station Unit NT1 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to fulfill BART requirements as well as new operating conditions consistent with BART requirements. A more stringent sulfur dioxide emission limitation, established by a rule change, will require the facility to reduce average fuel sulfur content through appropriate adjustments to its fuel mix.

Table 7-1. Summary of BART Determinations for Unit NT1

Pollutant	Current Emission Controls	BART Controls	BART Emission Limit
NO_X	Low-NOx burners, overfire air, and water injection	Low-NOx burners, overfire air, and water injection	0.35 lb/MMBtu (oil) and 0.25 lb/MMBtu (oil/gas), daily avg. (= RACT limit)
PM	ESP	ESP	0.22 lb/MMBtu total suspended particulate (TSP)
SO_2	2.0% sulfur content limit on residual fuel oil; 0.4% sulfur content limit on distillate fuel oil	SO_2 emission limitation of 0.50 lb/MMBtu, applicable to any fuel type or mix	0.50 lb/MMBtu, 30-day rolling average

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lb/gallon ÷ 150,000 BTU/gallon × 10^6 = 0.5 lb/MMBtu.

NEW HAMPSHIRE BART ANALYSIS: Newington Station Unit NT1 (400 MW)

Pollutant	Emission Control Technology	Approx. Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[6]					
						Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref./Note
NO$_X$	Combustion Controls (existing)	33%	1,407 [1]	943 [2]	464	—	—	—	—	—	
	LNB (typical)	40%	1,407 [1]	844	563	7,905,617	20	167,052	829,306	1,473	7
	LNB+OFA (typical)	50%	1,407 [1]	704	704	10,732,574	27	228,215	1,127,283	1,602	7
	SCR	85%	1,407 [1]	211	1,196	11,510,100	37	441,685	1,405,886	1,175	7
	SNCR	50%	1,407 [1]	704	704	3,298,475	12	451,026	727,339	1,034	7
PM	ESP (existing)	42%	338 [2]	196 [2]	142	—	—	—	—	—	
	Fabric Filters	99%	338 [2]	3	335	min. 23,426,952 max. 78,089,840	59 195	2,733,144 3,904,492	4,695,620 10,446,078	14,033 31,218	8
SO$_2$	2.0%-S oil (existing)	0% [3]	5,226 [2]	—	—	—	—	—	—	—	
	Switch to 1.0%-S oil	33% [4]	5,226 [2]	3,484	1,742	—	—	—	3,310,808	1,901	9
	Switch to 0.5%-S oil	67% [5]	5,226 [2]	1,742	3,484	—	—	—	6,621,615	1,901	10
	FGD	90%	5,226 [2]	523	4,703	422,000,000	1,055	unknown	unknown	unknown	11

[1] Estimated.

[2] 2002 (baseline) emissions reported in NHDES data summary as derived from facility's annual emissions statement.

[3] Actual average fuel sulfur content was ~1.2% in 2002. Over period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

[4] Based on an assumed average fuel sulfur content of 0.8%.

[5] Based on an assumed average fuel sulfur content of 0.4%.

[6] All cost estimates adjusted to 2008$.

[7] USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

[8] NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

[9] Stated costs represent premium for purchasing 1.0%-S oil at estimated price differential of 7.5¢/gal.

[10] Stated costs represent premium for purchasing 0.5%-S oil at estimated price differential of 15¢/gal.

[11] Based on $/kW estimated capital cost for comparable controls at Merrimack Station.

Newington Station Unit NT1: NO$_X$ Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data)

**Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	19.24	17.4	6,940,840	581,434	0.29	0.26	104,618	0.06	42,048	146,666	728,100	563	1,293
LNB+OFA	26.12	23.6	9,422,804	789,348	0.40	0.36	144,300	0.08	56,064	200,364	989,713	704	1,406
SCR	32.20	25.26	10,105,443	846,533	0.99	0.78	310,695	0.11	77,088	387,783	1,234,316	1,196	1,032
SNCR	10.80	7.24	2,895,939	242,593	0.17	0.11	45,584	0.50	350,400	395,984	638,577	704	907

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	21.91	19.76	7,905,617	662,254	0.33	0.30	119,160	0.07	47,893	167,052	829,306	563	1,473
LNB+OFA	29.75	26.83	10,732,574	899,068	0.46	0.41	164,358	0.09	63,857	228,215	1,127,283	704	1,602
SCR	36.68	28.78	11,510,100	964,201	1.13	0.88	353,882	0.13	87,803	441,685	1,405,886	1,196	1,175
SNCR	12.30	8.25	3,298,475	276,313	0.19	0.13	51,920	0.57	399,106	451,026	727,339	704	1,034

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Note: Cost estimates for LNB and LNB+OFA are based on referenced values for coal-fired plants; actual costs could be greater for oil- or gas-fired units.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Newington Station Unit NT1: PM Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr
Flue gas flow rate	1,714,000	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

2004$

Control Technology	Capital	Total Capital	Total Annualized Capital	Fixed O&M	Variable O&M	Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/acfm	$	$/yr	$/yr-acfm	$/yr-acfm	$/yr	$/yr	tons/yr	$/ton
Dry ESP	min. 15.00	25,710,000	2,153,727	0.25	0.45	1,199,800	3,353,527	142	23,616
	max. 40.00	68,560,000	5,743,271	0.65	0.60	2,142,500	7,885,771	142	55,534
Wet ESP	min. 15.00	25,710,000	2,153,727	0.15	0.25	685,600	2,839,327	142	19,995
	max. 40.00	68,560,000	5,743,271	0.50	0.50	1,714,000	7,457,271	142	52,516
Fabric Filter - Reverse Air	min. 17.00	29,138,000	2,440,890	0.35	0.70	1,799,700	4,240,590	335	12,673
	max. 40.00	68,560,000	5,743,271	0.75	0.80	2,656,700	8,399,971	335	25,103
Fabric Filter - Pulse Jet	min. 12.00	20,568,000	1,722,981	0.50	0.90	2,399,600	4,122,581	335	12,320
	max. 40.00	68,560,000	5,743,271	0.90	1.10	3,428,000	9,171,271	335	27,408

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Total Capital	Total Annualized Capital	Fixed O&M	Variable O&M	Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/acfm	$	$/yr	$/yr-acfm	$/yr-acfm	$/yr	$/yr	tons/yr	$/ton
Dry ESP	min. 17.09	29,283,690	2,453,095	0.28	0.51	1,366,572	3,819,667	142	26,899
	max. 45.56	78,089,840	6,541,586	0.74	0.68	2,440,308	8,981,893	142	63,253
Wet ESP	min. 17.09	29,283,690	2,453,095	0.17	0.28	780,898	3,233,993	142	22,775
	max. 45.56	78,089,840	6,541,586	0.57	0.57	1,952,246	8,493,832	142	59,816
Fabric Filter - Reverse Air	min. 19.36	33,188,182	2,780,174	0.40	0.80	2,049,858	4,830,032	335	14,434
	max. 45.56	78,089,840	6,541,586	0.85	0.91	3,025,981	9,567,567	335	28,592
Fabric Filter - Pulse Jet	min. 13.67	23,426,952	1,962,476	0.57	1.03	2,733,144	4,695,620	335	14,033
	max. 45.56	78,089,840	6,541,586	1.03	1.25	3,904,492	10,446,078	335	31,218

Newington Station Unit NT1: SO_2 Controls

SO_2 Control Cost Calculations for Switching from #6 Fuel Oil @ 2.0% S to Lower-Sulfur Fuel Oils @ 1.0 or 0.5% S:

Fuel Type	Maximum (Nominal) Fuel Sulfur[1]	Actual Fuel Sulfur	Annual Fuel Usage[4]	Annual SO_2 Emissions	Switch to Lower-S Fuel	Annual SO_2 Emission Reductions[7]	Blended Fuel Price Differential[8]		SO_2 Control Cost
	%S by wt	%S by wt	gal/yr	ton/yr	%S by wt	ton/yr	¢/gal	$/yr	$/ton removed
#6 Residual Oil	2.0	1.2 [2]	44,144,100	5,226 [5]	—	—	—	—	—
#6 ULS Residual Oil	1.0	0.8 [3]	44,144,100	3,484 [6]	2.0 to 1.0%	1,742	7.5 [9]	$3,310,808	$1,901
#6 ULS Residual Oil	0.5	0.4 [3]	44,144,100	1,742 [6]	2.0 to 0.5%	3,484	15.0 [10]	$6,621,615	$1,901

[1] Maximum allowable sulfur content of specified fuel.

[2] Actual average sulfur content of fuel burned in 2002. In the period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

[3] Assumed average sulfur content of specified fuel as assayed.

[4] *Actual fuel usage in 2002.*

[5] Actual 2002 emissions from CEM data.

[6] Estimated emissions based on stated fuel usage and estimated average sulfur content of specified fuel.

[7] Estimated emission reductions after switch to specified lower-sulfur fuel.

[8] *Estimated price difference between residual oil @ >1.0%S and residual oil @ ≤1%S, based on EIA fuel price data for all U.S. locations, 1983-2008.*

[9] Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.8%S actual (1.0% nominal).

[10] Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.4%S actual (0.5% nominal).

SO_2 Control Cost Calculations for Flue Gas Desulfurization:

As an approximation, assume that FGD capital cost for Newington Station would be comparable to that for Merrimack Station on a $/kW basis.

Merrimack Station has an estimated capital cost of $1,055/kW, based on PSNH's 2008 estimate of $457 million for Unit MK1 (113 MW) and Unit MK2 (320 MW) combined.

Newington Station Unit NT1 has a generating capacity of 400 MW (=400,000 kW).

Estimated capital cost for FGD on Unit NT1 = 400,000 kW × $1,055/kW = $422,000,000.

Enclosure to Letter from PSNH to DES ARD, dated 12/4/09

NOTE: This sheet is a re-creation of PSNH's tables, with formulas inserted and additional calculations. All changes and additions to the original are shown in blue.

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	AP-42** SO2 lb/1000gal	AP-42*** SO2 lb/mmbtu	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr	Fuel Switch	increased cost/barrel****		increased cost/hr*****		$/ton SO2 Reduced	
								low	high	low	high	low	high
2.0	314.0	2.041	2.288	4,350	9,952.8								
1.0	157.0	1.021	1.086	4,350	4,724.1	5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
0.7	109.9	0.714	0.748	4,350	3,253.8	1,470.3	1% to 0.7%	$1.00	$3.30	$673.21	$2,221.61	$414	$3,022
0.5	78.5	0.510	0.528	4,350	2,296.8	957.0	0.7% to 0.5%	$1.00	$2.20	$673.21	$1,481.07	$586	$3,095
0.3	47.1	0.306	0.313	4,350	1,361.6	935.3	0.5% to 0.3%	$3.00	$9.00	$2,019.64	$6,058.93	$2,967	$12,957
				4,350		5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
				4,350		6,699.0	2% to 0.7%	$2.00	$7.00	$1,346.43	$4,712.50	$402	$1,407
				4,350		7,656.0	2% to 0.5%	$3.00	$9.00	$2,019.64	$6,058.93	$528	$1,583
				4,350		8,591.3	2% to 0.3%	$4.00	$17.00	$2,692.86	$11,444.65	$627	$2,664

(A) % sulfur in the fuel oil
(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal
(C) Maximum gross heat input rate from permit
(D) SO2 lb/hr emission rate, calculated = B * C
(E) Lbs of SO2 reduced per hour

** Source: USEPA, Compilation of Air Pollutant Emission Factors, AP-42, 5th Ed., Vol. 1. Section 1.3 - Fuel Oil Combustion (9/98)
*** Based on fuel heating value of 153,846 BTU/gal
**** From historical fuel cost table, approximate.
***** $/barrel ÷ 42 gal/barrel ÷ 0.153846 mmBTU/gal × mmBTU/hr = $/hr

	Actual Fuel Use	Historical Fuel Cost				
	#6 oil (barrels)	2%S Oil ($/barrel)	1%S Oil ($/barrel)	0.7%S Oil ($/barrel)	0.5%S Oil ($/barrel)	0.3%S Oil ($/barrel)
2002	1,051,050	$21.20	$22.45	$23.26	$23.80	$25.25
2003	3,425,217	$24.95	$27.48	$29.26	$30.45	$32.63
2004	3,099,258	$25.25	$27.92	$30.04	$31.46	$34.53
2005	2,027,172	$37.00	$41.00	$44.00	$46.00	$50.10
2006	392,922	$45.50	$46.30	$48.46	$49.90	$54.12
2007	529,092	$53.70	$53.45	$56.54	$58.60	$62.86
2008	201,172	$75.25	$77.80	$81.10	$83.30	$92.16
2009	118,246	$49.90	$50.75	$51.98	$52.80	$55.83

Historical fuel cost data from Platts 2002-2009.
2009 data includes costs through 9/09 only.

*Estimates calculated illustrate cost increases based on assumptions relied upon.

chm
12/08/09

Supporting Documentation for BART Analyses

- PSNH Correspondence, December 4, 2009
- PSNH Correspondence, July 9, 2010
- PSNH Correspondence, August 16, 2010
- PSNH Correspondence, December 15, 2010

Public Service of New Hampshire

PSNH Energy Park
780 North Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P.O. Box 330
Manchester, NH 03105-0330
(603) 634-2236
Fax (603) 634-2213
macdojm@psnh.com

The Northeast Utilities System

John M. MacDonald
Vice President - Generation

December 4, 2009

Mr. Robert R. Scott, Director
Air Resources Division
Dept. of Environmental Services
29 Hazen Drive, PO Box 95
Concord, NH 03302-0095

Public Service Company of New Hampshire
Request for Additional Information for Determination of
Best Available Retrofit Technology (BART) for the NH Regional Haze SIP

Dear Mr. Scott:

In response to your request, dated November 17, 2009, for additional information necessary to finalize the NH Department of Environmental Services, Air Resources Division's response to comments received from the U.S. Environmental Protection Agency and Federal Land Managers specific to DES' Best Available Retrofit Technology (BART) demonstration, Public Service Company of New Hampshire is submitting the enclosed information.

As you know, PSNH did not submit written comments specific to DES' BART determination presented at the public hearing on June 24, 2009, because PSNH was in agreement with that determination. PSNH is interested in understanding the basis of any significant changes to the BART determination and would raise objection to overly stringent BART limits that provide minimal environmental benefit yet increase costs and expose PSNH's generating facilities to permit exceedances during the course of normal operation of the units.

Incremental Cost Estimates of SO2 Reductions at Newington Unit NT1

In order to estimate incremental costs associated with varying grades of oil, PSNH evaluated historical fuel cost data provided by Platts for the period of 2002 through September 2009. Considering the inevitable inaccuracies in trying to predict future fuel prices, PSNH has calculated incremental cost estimates for illustrative purposes using the more recent historical fuel cost data (2005-2009).

As illustrated on the enclosed spreadsheet, PSNH has estimated the incremental costs, on a dollar per ton basis, of sulfur dioxide reductions at Newington Station, Unit NT1 to be as follows:

2% sulfur content by weight to 1% sulfur content by weight	$1,030 per ton SO2 reduced
1% sulfur content by weight to 0.7% sulfur content by weight	$2,949 per ton SO2 reduced
0.7% sulfur content by weight to 0.5% sulfur content by weight	$7,203 per ton SO2 reduced
0.5% sulfur content by weight to 0.3% sulfur content by weight	$12,957 per ton SO2 reduced

Assumptions Used to Produce Estimated Incremental Costs

The assumptions used to estimate incremental costs include historical fuel prices, maximum gross heat input rate of Unit NT1, SO2 emission rates in lb/mmBtu and lb/hr for each grade of fuel, and tons of SO2 reduced. Capacity factor of Unit NT1 is not necessary to calculate incremental costs on a dollar per ton reduced basis. The SO2 emission rates were derived from the sulfur content of the fuel, the heating value of the fuel, and the maximum gross heat input rate of Unit NT1. The tons of SO2 reduced were calculated using the delta in SO2 emissions between each fuel type on a lb/hr basis which was calculated using the SO2 lb/mmBtu emission rate for each grade of fuel and the maximum gross heat input rate of Unit NT1 as contained in Newington Station's Title V Operating Permit, TV-OP-054.

Additional Costs Associated with Fuel Storage Upgrades at Newington Station

At the present time, PSNH is hopeful that the current fuel storage and delivery system, including configuration and storage capacity, is adequate to handle varying grades of oil if required in the future. As a result, PSNH has not calculated additional costs associated with fuel storage upgrades.

MK Unit #2 Boiler and SCR Operations

The SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. As an example, Merrimack Unit 2 typically has 10 to 15 outages per year, in addition to approximately 8 low load operating periods per year. The timing of these conditions is not predictable and this estimate of occurrences provided reflects historical performance. Examples of low load situations include, but are not limited to: forced and planned outage start ups and shutdowns, loss of one of any equipment pair where both pieces of equipment are necessary for full load operation and the loss of one results in half load operation (such as Forced Draft Fans, Condensate Pumps), loss of the Main Boiler Feed Pump, loss of coal feeders, condenser waterbox cleaning, etc. Any condition which requires the unit be at loads below 230 mw net, causing the temperature to be below the SCR permissive will result in the SCR not able to be put in service. This load point may increase with the new, more efficient HP/IP turbine.

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

As part of normal service, the SCR catalyst becomes coated with flyash. Blinding of the catalyst with flyash can cause the SCR process control settings (often referred to as the setpoint) to have to be increased (less NOx conversion), as the reagent distribution becomes less uniform and as less catalyst is exposed to the flue gas. The SCR is cleaned as needed during outages, and sootblowers are used on line.

Reagent injection grid nozzles, being in the flue gas path, can become fouled with deposits. This can affect reagent distribution, compounding the effect of a fouled catalyst, for example. The reagent injection grid is cleaned, as needed, during outages. Also, reagent delivery disruption can occur and on-site storage is limited.

Also as a catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emission because the SCR has four layers of catalyst, staggered in age. However, it will compound the effect of a fouled catalyst, for example.

The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU.

The SCR is unable to perform continually at its maximum capability due to these concerns. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions.

In closing, PSNH would like to reiterate its opinion that changes to DES' BART determination that result in more stringent emissions limitations create concerns relative to increased costs and decreased operational flexibility.

Please contact Laurel L. Brown, Senior Environmental Analyst – Generation, at 634-2331 if you would like additional information or would like to meet to discuss the enclosed information further.

Sincerely,

John M. MacDonald
Vice President – Generation

Enclosure

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr		increased cost/barrel		increased cost/hr		$/ton SO2 Reduced
						low	high	low	high	
2.0	2.288	4,350	9,952.8							
1.0	1.086	4,350	4,724.1	5,228.7	2% to 1%	0	$ 4.00	0	$ 2,692.86	$ 1,030
0.7	0.748	4,350	3,253.8	1,470.3	1% to 0.7%	$ 1.00	$ 3.30	$ 673.21	$ 2,167.75	$ 2,949
0.5	0.528	4,350	2,296.8	957.0	0.7% to 0.5%	$ 1.00	$ 2.20	$ 673.21	$ 3,446.86	$ 7,203
0.3	0.313	4,350	1,361.6	935.3	0.5% to 0.3%	$ 3.00	$ 9.00	$ 2,019.64	$ 6,058.93	$ 12,957

(A) % sulfur in the fuel oil

(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal

(C) Maximum gross heat input rate from permit

(D) SO2 lb/hr emission rate, calculated = B * C

(E) Lbs of SO2 reduced per hour

	Actual Fuel Use	Historical Fuel Cost				
	#6 oil (barrels)	2%S oil ($/barrel)	1%S oil ($/barrel)	0.7%S oil ($/barrel)	0.5%S oil ($/barrel)	0.3%S oil ($/barrel)
2002	1,051,050	$ 21.20	$ 22.45	$ 23.26	$ 23.80	$ 25.25
2003	3,425,217	$ 24.95	$ 27.48	$ 29.26	$ 30.45	$ 32.63
2004	3,099,258	$ 25.25	$ 27.92	$ 30.04	$ 31.46	$ 34.53
2005	2,027,172	$ 37.00	$ 41.00	$ 44.00	$ 46.00	$ 50.10
2006	392,922	$ 45.50	$ 46.30	$ 48.46	$ 49.90	$ 54.12
2007	529,092	$ 53.70	$ 53.45	$ 56.54	$ 58.60	$ 62.86
2008	201,172	$ 75.25	$ 77.80	$ 81.10	$ 83.30	$ 92.16
2009	118,246	$ 49.90	$ 50.75	$ 51.98	$ 52.80	$ 55.83

Historical fuel cost data from Platts 2002-2009

2009 data includes costs through 9/09 only.

* Estimates calculated illustrate cost increases based on assumptions relied upon.

Public Service of New Hampshire

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The Northeast Utilities System

~~CONFIDENTIAL~~, Released per Nov 3, 2010 Letter to PSNH

Rcvd via e-mail on July 16, 2010

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NEW HAMPSHIRE

JUL 16 2010

AIR RESOURCES DIVISION

July 9, 2010

Michele Roberge
Administrator, Permitting and Environmental Health Bureau
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
PO Box 95
Concord, NH 03302-0095

~~CONFIDENTIAL BUSINESS INFORMATION~~

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Ms. Roberge:

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits and the Newington (NT1) fuel oil sulfur content for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers and the associated costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP

1. Operating Temperature of SCR

As previously provided, the SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. For example, Merrimack Unit 2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are less than the permissive temperature rendering the SCR inoperable. The timing of these events is not predictable; the estimate of occurrences provided reflects historical performance.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;

- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

2. Malfunction and Fouling of the SCR and/or Associated Equipment

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also as part of normal service, the SCR performance degrades over time. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading will lead to more frequent maintenance outages. Reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of a fouled catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, it will compound the effect of a fouled catalyst and can result in the SCR being unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU. The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU.

With these short-term challenging operational conditions, PSNH's greatest concern is ensuring consistent compliance. We have reviewed historical data and concluded that start-ups and shut downs can significantly impact both a calendar month and a rolling 30-day average emission rate by up to 0.04 lb NOx/mmBTU. If there is more than 1 outage during the averaging period, the impact to the average emission rate could be as high as 0.08 lb NOx/mmBTU. To allow for this potential operating occurrence, Merrimack Station would need to operate to maintain a much lower average NOx rate. Reviewing the historical monthly averages, this leaves little margin for typical operating fluctuations in NOx controls. For example, if a unit is off for a longer period of time, there are less valid operating days available to be included in average rate. This analysis is particularly interesting, because in this specific scenario, the total tons of emissions are less than full load operation for the same averaging period, but could have a high emission rate. An extreme example of this scenario was observed in August 2009 when the monthly average emission rate was 0.813 lb NOx/mmBTU and yet total emissions for that month were approximately 1 ton. This was primarily due the unit operating only a short amount of time in that month.

3. Potential Costs Associated with Proposed Reduction in NOx emission rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater cleanings will be required more frequently because of increased loading of the SCR. This scenario results in additional maintenance costs and replacement power costs associated with the required outages.

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of ~ $30/mwhr difference between the cost of Merrimack Station and the market cost. This number can vary greatly depending on energy market prices.

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Number of outages per year	Total Cost per Year
Short (3 days)	$720,000	1	$720,000
		2	$1,440,000
		3	$2,160,000
		4	$2,880,000
Mid (4.5 days)	$1,100,000	1	$1,100,000
		2	$2,200,000
		3	$3,300,000
Long (6 days)	$1,400,000	1	$1,400,000
		2	$2,800,000

If air heater washings were routinely necessary to comply with a step change in the NOx rate, the cost per ton of NOx reduction would be extremely costly, as illustrated below. This cost can increase greatly if an air heater cleaning was completed during a high priced market.

Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental tons per year	Incremental tons per day
0.37	5628.34		
0.34	5171.99	456.35	1.25

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Incremental tons per year	Cost per Ton
Short (3 days)	$720,000	456.35	$1,578
Mid (4.5 days)	$1,100,000	456.35	$2,410
Long (6 days)	$1,400,000	456.35	$3,068

Examples of other compliance measures that would be necessary include accelerating the catalyst replacement in the SCR management plan. Currently, one layer of catalyst is exchanged every 2 years. To revise this plan by exchanging one layer every year would result in a project expense of approximately $2 million every other year. Increasing the frequency of catalyst replacement would result in approximately $12 million over the period 2013 thru 2025. This revised replacement plan would not likely result in additional total reduced tons of NOx for the year, but rather help manage the brief periodic increased emission rates associated with the events described above.

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time--and thus do not result in the emission of a significant amount NOx emissions. For example, the flexibility of partial load operation during high demand periods is important to the electrical reliability of the grid and can significantly protect customers from high energy costs during these peak events. It would not be in the public interest to require the unit to come off line since such action would be extremely costly to both reliability and to customers. A half day of no operation when energy prices are over $100mwh will be $250,000, $350,000 or greater; a cost that would yield a NOx reduction of only approximately 10 – 15 tons.

This discussion demonstrates that the implementation of a calendar month and rolling 30 day lb/mmbtu NOx emission rate can result in significant cost to our customers with little environmental benefit. To avoid permit exceedences due to a short-term NOx rate excursion, would require running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages.

Replacement power cost associated with outages:

	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	$30	$239,040	$15,936
	$40	$318,720	$21,248
	$50	$398,400	$26,560
2 days	$30	$478,080	$15,936
	$40	$637,440	$21,248
	$50	$796,800	$26,560

*assumes saving of 15 tons per day ..

As you are aware, Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable, affordable power, but to do that successfully, we do require operational flexibility. It is critical to understand that such operational flexibility will ensure consistent compliance with the monthly average emission rate while not significantly increasing total NOx emissions.

Newington Station- additional fuel oil information

In your June 15, 2010 email, you also requested information regarding Newington Station's current oil stocks, storage capacity, fuel usage rates, and operational considerations and costs associated with switching to lower sulfur fuels required by the NH Regional Haze SIP. That information is provided below.

Please describe the current oil stocks (type and quantity) and storage capabilities.

Newington Station has the capacity to store approximately 732,500 barrels (31 million gallons) of fuel oil in four separate above ground storage tanks (identified as NT-1, NT-2, SR-2, and SR-3). Currently, these four tanks contain approximately 485,000 barrels (20 million gallons) of No. 6 fuel oil with an average sulfur concentration of approximately 1%.

How many hours of operation would this supply at current usage rates? What are the rates that this estimate is based on?

Due to various economic conditions, including the rising cost of No. 6 fuel oil, lower natural gas prices and electric demand, Newington Station has burned only a limited volume of oil in the past couple years. Current conditions are not expected to change considerably in the short term, therefore, Newington does not anticipate consuming a significant volume of oil in the next couple of years.

It is difficult to assess how long it would take to deplete this fuel oil inventory since fuel oil usage is dependent on market conditions and the demand for electricity. Newington Station will choose the fuel or blend of fuel (oil, natural gas, or natural gas and oil) based on the desired electrical output and the cost of fuel. As you are aware, Newington Station will use the most cost effective fuel to maintain its electric costs for the customer.

In an effort to understand how this inventory relates to future operating conditions, PSNH has looked at different operating scenarios to estimate the length of time it may take to deplete this inventory. The scenarios include different operating loads, a fuel mix of 75% natural gas and 25% fuel oil, and an operating capacity factor of 5% (see table below). Although, PSNH can not reliably predict with any certainty how Newington Station will operate in the next couple years, for purposes of this evaluation, PSNH has assumed an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, 75% natural gas/25% oil blend, and a capacity factor of 5%.

Based on current fuel oil inventory levels, and the scenario presented above, Newington Station would deplete its existing fuel supply in 16 years.

MW	Btu/kWh	Btu/gal Oil	Capacity Factor %	BBl/yr	75% gas/25% oil BBl/yr	Projected depletion of current inventory (yrs)
400	10,793	153,846	5	292,645	73,161	7
150	11,750	153,846	5	119,533	29,883	16
100	13,860	153,846	5	93,951	23,488	21
60	16,560	153,846	5	67,352	16,838	29

Note:
Assuming an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, a 75%/25% gas/oil blend, and a capacity factor of 5%, the current inventory would be depleted in 16 years. This scenario is Newington Station's best estimate based on current operating history.

What are the specific operational considerations in switching to 0.3% S oil that do or do not make it feasible and costly?

PSNH understands that the Regional Haze SIP will require Newington Station to burn 0.5% or 0.3 % sulfur oil as part of its compliance strategy as early as 2013. In order to prepare for this requirement, Newington Station would need to have the available capacity to store the lower sulfur oil. Due to a variety of factors that affect the availability and cost of natural gas, PSNH believes it would be necessary to empty one of the larger bulk fuel oil storage tanks, at a minimum, to provide the storage capacity of the lower sulfur fuel. Our largest tanks (NT1 and NT-2) currently contain approximately 160,000 barrels each of fuel oil. Based on the likely operating scenario presented above, it will take more than 5 years to empty one of the larger tanks.

In this scenario, Newington would either need to operate and utilize the on-hand fuel or sell some of its current inventory if an acceptable process could be identified. It is difficult to estimate what the cost to PSNH would be if this were required, since the value of this oil in 3 years is unknown.

PSNH currently knows of no way other than consuming oil in the unit to dispose/deplete our current inventory. Although offloading oil from the tanks to a barge or ship is being considered, Newington's oil terminal was designed to accept deliveries of oil from fuel vessels and was not designed to load vessels from the oil tanks. Newington Station also does not have the capability for loading trucks from the oil tanks. Any risk to personnel safety or the environment would need to be fully eliminated to consider a transfer of oil to a vessel or truck. Therefore, at this point, it is assumed that Newington Station would be required to burn the oil in the unit at a potential incremental cost to NH customers. Consistent with the numbers above, to burn 160,000 barrels of oil to empty one of the larger tanks, the unit would have to operate an equivalent of 24 hours/day for approximately 10 days at 400 MWs. Also, as stated above, due to economic conditions, Newington Station has been reserved to protect customers from high priced market excursions. If we assume consumption of the inventory of oil is required, then it will be necessary for Newington to operate at rates higher than market rates. In this case, based on an incremental cost of $80 per MWH, the total cost to customers will be approximately $8 million. This is a significant cost to customers which has no associated environmental benefit.

Blending this higher sulfur fuel with lower sulfur fuel or natural gas over time is a more cost effective option and will not result is greater emissions as compared to a targeted depletion effort described in the above scenario. Although it is possible to consider the depletion of current fuel oil inventories by blending with natural gas, natural gas is not always available and could not be relied upon as a sole compliance option.

What are the estimated costs of making the switch; both capital and operating costs?

As presented in our earlier December 4, 2009 letter, the cost to PSNH in going from a 1% sulfur oil to a 0.5% sulfur oil could be as high as $42/bbl (based on fuel oil prices from 2005-2009). Similarly, the cost to PSNH in going from 1% sulfur oil to 0.3% sulfur oil could be as high as $51/bbl. Using the same operating scenario presented above, this equates to an additional cost to PSNH customers of $1.2 million/year for the use 0.5% sulfur fuel and $1.5 million/year for the use 0.3%.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Technical Business Manager – Generation

cc:
Sheila Burke, Generation Staff
Tara Olson, Newington Station

August 16, 2010

Released
Per Nov 3, 2010
Letter fr
PSNH

~~CONFIDENTIAL BUSINESS INFORMATION~~

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

SUPPLEMENTAL INFORMATION to PSNH's July 16 Letter, Response to Request for Additional Information re: BART

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shutdowns, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated. In most cases the timing of these events is not predictable.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

A more stringent limit could result in the unnecessary shutdown of the unit rather than operating at partial load. An example of this scenario has occurred in the past when a critical pump failed which restricted full load operation. While the pump was repaired the unit remained operating but at a reduced capacity, the duration of this event was approximately 240 hours. PSNH's customers received significant benefit from this partial load operation. Replacement power costs associated with this type of event are shown in the Table 1.

> **Replacement Power Costs:** The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu
Assumes 0.64 tons per hr

Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$0
100 hr	132 MW	200 MW	$ 600,000	$0
50 hr	132 MW	200 MW	$ 300,000	$0

Table 1b. Cost Associated with limited De-rate Flexibility at 0.34 lb/MMBtu
Assumes 0.59 ton per hr

Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Un-avoided Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$10,169
100 hr	132 MW	200 MW	$ 600,000	$10,169
50 hr	132 MW	200 MW	$ 300,000	$10,169

The opportunity for partial load operation during high demand periods would be even more costly to both reliability and to customers. The example mentioned above resulted in a long duration of partial load operation but it is important to note that during periods of high energy prices a much shorter event could also have significant cost. For example, assuming a $100 per MWh market price, operating at 200MW partial load for a period of 12-hours would avoid $240,000 of replacement power cost. During this period a NOx reduction of approximately 7 tons would be realized which equates to $34,000 per ton NOx. Under some of these scenarios partial load operation would be eliminated to ensure consistent compliance with the proposed NOx limit reduction.

2 – Maintenance Impacts

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact a calendar month average emission rate. To account for these events PSNH operates NOx control equipment to maintain a NOx emission rate of approximately 0.25 lb/MMBtu calendar month average. In order to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate, PSNH targets a 0.15 lb/MMBtu difference between the average NOx emission rate and the specific limit. Further limitations would impact operation and increase incremental maintenance and capital cost.

In addition to boiler operation and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also, as part of normal service, the SCR performance degrades overtime. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading could lead to more frequent maintenance outages. It is anticipated that a minimum of three additional SCR cleanings and air heater washes would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed NOx limit. Cleanings are expected cost between $30,000 and $100,000 as noted below in item 3. Replacement power costs associated with the necessary maintenance outages are also described in item 3 below.

Additionally, reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of blinded catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, increased loading of the SCR catalyst would be necessary to maintain compliance with the proposed reduction in NOx limit and accelerate catalyst degradation. For example, the SCR is unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency.

Each catalyst layer has an anticipated functional life of 8 years and each layer is staggered in age to accommodate replacing one layer every 24 –months. Further NOx limitation would increase loading of the SCR and could result in accelerated catalyst degradation requiring premature replacement. This would result in a loss of investment. Even if minor catalyst degradation occurred reducing the catalyst useful life from 8 years to 7.5 years the replacement schedule would need to be adjusted. The change in replacement schedule is necessary because catalyst replacement projects must coincide with MK2's overhaul schedule which is on a 12-month cycle. PSNH would incur a loss of investment of approximately $143,000 annually due to the early replacement. It is also important to note that the revised replacement plan would result in minimal reductions to the total reduced tons of NOx for the year, but rather be put in place to avoid the periodic increased emission rates at the end of the catalyst life. As shown below in Table 2, PSNH believes minimal catalyst replacement and maintenance cost are associated with the 0.37 lb/MMBtu rates provided certain exceptions for start-up and shutdown and malfunctions.

Table 2. Incremental Maintenance and Capital Cost				
Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

3 –Replacement Power Costs associated with the Proposed Reduction in NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. It is anticipated that at least one additional 4.5 day (mid) maintenance outage would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed limit. In addition to the maintenance outage additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. Potential Emission Summary (8760 hrs)		
Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental reduction in <u>Potential</u> emissions tons per year
0.37	5628.34	0
0.34	5171.99	456

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 5. Impact of 0.34 lb/MMBtu Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	\$720,000
Mid (4.5 days)	\$1,100,000
Long (6 days)	\$1,400,000

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time thus do not result in the emission of a significant amount of NOx emissions. To meet the proposed rates of 0.34 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above.

Also, with out exceptions for short term operational conditions additional incremental costs may be incurred when considering a calendar month averaging period. PSNH may be forced to delay start-up to maintain a 0.34 lb/MMBtu calendar month average. It is important to note that start-up shutdowns, and partial load operating scenarios may bias a lb/MMBtu rate but typical result in low tonnage emission total. To manage for this situation it may be necessary for PSNH to adjust the current operating strategy by delaying start-ups or to prevent a short operating periods during the calendar month. Table 6., below illustrates the potential cost with delaying an outage start-up.

Table 6. Replacement power cost associated with delayed start-up			
	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	\$30	\$239,040	\$15,936
	\$40	\$318,720	\$21,248
	\$50	\$398,400	\$26,560
2 days	\$30	\$478,080	\$31,872
	\$40	\$637,440	\$42,496
	\$50	\$796,800	\$53,120

*assumes saving of 15 tons per day

4 - Summary of Analysis

Merrimack Station has had a program in place to reduce NOx emissions for the past 15 years. The reductions in total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. It is critical to understand adjusting the NOx rate will significantly increase the incremental costs of compliance without significantly decreasing total NOx emissions. This effort will have virtually no effect on MK2's actual emissions and is focused on limiting MK2's potential emission which results in eliminating operational flexibility and increasing operating costs. Table 7. below is a summary of the incremental costs that PSNH will incur when considering the 0.34 lb/MMBtu proposed NOx emission rate.

Table 7. Summary of Additional Predicted Annual Cost

Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Loss of Investment of SCR Catalyst per year	Un-avoidable Replacement Power cost (Partial Load) @ 240 hrs	Increase Maintenance (Cost of Air heater and SCR Maintenance) 3 per year	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater 2days (One day each for two outages)	Incremental reduction in <u>Potential</u> tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0.22	$0	$0	$0	$0	$0	0	$0	$0
0.34	0.19	$143,000	$1,440,000	$195,000	$1,100,000	$478,080	456	$3,356,080	$7,359

This analysis demonstrates that the implementation of a 0.34 lb/MMBtu or more stringent rate will result in significant cost to our customers with little environmental benefit. This is true because a lb/MMBtu rate could result in running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact Lynn Tillotson at 634-2440 or Sheila Burke at 634-2512.

cc:
Elizabeth H. Tillotson, TBM, Generation Staff
Sheila Burke, Generation Staff
Tara Olson, Newington Station

Public Service
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The Northeast Utilities System

December 15, 2010

Robert Scott
Director
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
PO Box 95
Concord, NH 03302-0095

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Mr. Scott:

As requested in your December 8, 2010 letter, PSNH provides the following additional information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP.

Merrimack Station Unit #2:

Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

This submittal will analyze the 0.30 lb/MMBtu emission rate averaged on a 30-day rolling basis as well as the impact of a more stringent limit. A 30-day rolling average is defined as the arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating day[1]. This definition is consistent with November 22, 2010 comments provided by EPA pertaining to the draft rule.

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[1] *Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. (40 CFR 60 Subpart Da)

The summary of the analysis is provided in the following table, all supporting calculations and basis for this determination are detailed in the items below.

Summary of Analysis			
Emission Limit (lb/MMBtu)	Incremental reduction in **Potential** tons per year[2]	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0	$0	$0
0.30	1,065	$880,000	$826
0.25 – 0.30	380	$2,888,000	$7,600

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

The ability to manage these events is beneficial to our customers. Adequate flexibility allows the high cost of replacement power to be minimized. Limiting operational flexibility could result in the unnecessary shutdown of the unit rather than operating at partial load. Tables 1a. and 1b. below demonstrate the replacement power cost associated with a 0.30 lb/MMBtu, 30-day rolling average emission rate. The opportunity for partial load operation during high demand periods would be even more valuable to both reliability and to customers.

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[2] Incremental reduction of Potential emissions is the calculated mean of the 0.25-0.30 range.

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu
Assumes 0.64 tons per hr

Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
240 hr	132 MW	200 MW	$1,440,000
100 hr	132 MW	200 MW	$600,000
50 hr	132 MW	200 MW	$300,000

Table 1b. Cost Associated with limited De-rate Flexibility at 0.30 lb/MMBtu
Assumes 0.51 ton per hr

Un-Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Un-avoided Replacement Power Cost
240 hr	132 MW	200 MW	$1,440,000
Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
100 hr	132MW	200 MW	$600,000
50 hr	132MW	200 MW	$300,000

The table is based on a steady state NOx emission rate of 0.22 lb/MMBtu and a NOx emission rate of 0.8 lb/MMBtu during partial load operation. The maximum number of days MK2 can operate in a partial load is 4.2 days (100 hrs) when considering a 0.30 lb/MMBtu 30-day rolling emission limit.

It should be noted previous submittals did not consider the rolling averaging method, because the existing Data Acquisition and Handling System (DAHS) is not configured for this averaging period. Based on EPA comments of the proposed Env-A 2300 Rule, PSNH has consulted the software vendor which supplies the DAHS and is reviewing the best available option to manage this averaging period. Current method of achieving this is through a new "Smart Reporting" software trial program. PSNH is confident in working with the vendor that the rolling average period will be achievable. Preliminary information suggests that implementing the new software has an estimated cost of $10,000 and an annual recurring cost of $2,000.

2 – Maintenance Impacts

Calendar Month Analysis (Previously Submitted):

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact average emission rates. PSNH's current method of operation to account for these events is to operate NOx control equipment to maintain an emission rate of approximately 0.25 lb/MMBtu calendar month average to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate. This method of operation results in approximately a 0.15 lb/MMBtu difference between the average NOx emission rate and the limit, this allows for operational flexibility as described above (i.e. start-up, shutdown, partial load operation etc). Further limitations based on a calendar month would impact operation and increase incremental maintenance and capital cost. For complete breakdown of the costs represented in Table 2a. and a calendar month analysis reference PSNH's August 16, 2010, submittal.

Table 2a. Incremental Maintenance and Capital Cost

Emission Limit (lb/MMBtu)	**Calendar** Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

30-Day Rolling Average analysis:

In addition to the above analysis and based on EPA comments to the draft rule and DES's request for additional information, PSNH further analyzed the impact of changing its current method which is based on a calendar month average and reviewed a 30-day rolling emission limit, as well as the incremental cost associated with this limit. PSNH agrees with EPA that the 30-day rolling average method addresses flexibility for start-up, shutdown, emergency and malfunction. However, additional flexibility is necessary to maintain short term partial load capability.

PSNH has determined that a 0.30 lb/MMBtu emission rate on a 30-day rolling average will accommodate reasonably anticipated operating scenarios while achieving approximately 20% reduction in potential emissions. The maintenance costs that will be incurred by complying with this limit is estimated to be $30,000 per year, and can be attributed to additional cleaning and inspection of the SCR and air heater. PSNH also analyzed more stringent limits and determined costs similar to those represented in Table 2a above would be incurred. The increase cost associated with a more stringent limit can be attributed to the cascading effect of increased loading of the SCR.

Increased loading of the SCR results in the following conditions each more impactful as loading increases. More detail associated with these conditions can be found in the August 16, 2010, PSNH submittal.

1) Blinding of Catalyst;
2) More Frequent Maintenance Outages;
3) Fouled reagent distribution nozzles;
4) Accelerated catalyst derogation; and
5) Loss of Investment of catalyst.

Table 2b Incremental Maintenance and Capital Cost based on 30-day Rolling Average			
Emission Limit (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	$0	$0	$0
0.30	$0	$30,000	$30,000
0.25-0.30	$143,000	$195,000	$338,000

As noted in condition 2 above there will likely be additional maintenance outages to ensure optimum SCR performance. Replacement power costs that customers would incur from an additional maintenance outage are described in Item 3.

3 – Replacement Power Costs associated with more stringent limit than 0.30 lb/MMBtu NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with events as described above.

Increased maintenance costs to maintain peak NOx reduction capability could be signifcant. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. In addition to the maintenance outages additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. Impact of more stringent Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	$720,000
Mid (4.5 days)	$1,100,000
Long (6 days)	$1,400,000

Replacement Power Costs: The table uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

It should be reiterated to meet more stringent emission rate than 0.30 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above in Table 5.

4 - Summary of Analysis

Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. Table 4. below is a detailed summary of the incremental costs that PSNH will incur when considering the 0.30 lb/MMBtu proposed NOx emission rate and a more stringent limit.

Table 4. Summary of Additional Predicted Annual Cost[3]

Emission Limit (lb/MMBtu)	**Unavoidable** Replacement Power cost (Partial Load) @ 240 hrs	New DAHS Implementation	Increase Maintenance (Cost of Air heater and SCR Maintenance 3 per year	Loss of investment of the SCR Catlyst	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater (Two days)	Incremental reduction in **Potential** tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	$0	$0	$0	$0	$0	$0	0	$0	$0
0.30	$840,000	$10,000	$30,000	$0	$0	$0	1,065	$880,000	$826
0.25-0.30	$1,440,000	$10,000	$165,000	$143,000	$1,100,000	$0	380	$2,888,000	$7,600

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[3] Values represented in Table 4 are net values.

PSNH understand the cost per ton of complying with the 0.30 lb/MMBtu calculated on a 30-day rolling average is under the BART threshold and is willing to accept this limit, which results in approximately 20% reduction of MK2's potential NOx emissions. This analysis demonstrates that the implementation of a more stringent limit than 0.30 lb/MMBtu will result in significant cost to our customers with little environmental benefit. With running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H Tillotson

Elizabeth H. Tillotson
Technical Business Manager – Generation

cc:
Sheila Burke, Generation Staff
David Cribbie, Generation Staff

ATTACHMENT Y

Assessment of Reasonable Progress for Regional Haze In MANE-VU Class I Areas

FINAL

Assessment of Reasonable Progress for Regional Haze In MANE-VU Class I Areas

Methodology for Source Selection, Evaluation of Control Options, and Four Factor Analysis

Prepared for:

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July 9, 2007

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List of Acronyms

AFGD	Advanced Flue Gas Desulfurization
BACM	Best Available Control Measure
BART	Best Available Retrofit Technology
BLM	Bureau of Land Management
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CO_2	carbon dioxide
DOE	Department of Energy
EGU	Electric Generating Unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
ICI	Industrial, Commercial, Institutional
IPM®	Integrated Planning Model
kW	kilowatt
kWh	kilowatt-hour
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X Burner
LSD	Lime Spray Drying // Low Sulfur Diesel
LSFO	Limestone Forced Oxidation

List of Acronyms - continued

MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MEL	Magnesium Enhanced Lime
MM	million
MMBTU	Million British Thermal Units
MRPO	Midwest Regional Planning Organization
MW	Megawatt
NESCAUM	Northeast States for Coordinated Air Use Management
NO_X	nitrogen oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O&M	Operation and Maintenance
OFA	Over-fire Air
PADD	Petroleum Administration for Defense District
PM	Particulate Matter
PM_{10}	Particulate Matter with diameter 10 micrometers or less
$PM_{2.5}$	Particulate Matter with diameter 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measure
RACT	Reasonably Available Control Technology
RWC	Residential Wood Combustion
SACR	Selective Auto-catalytic Reduction
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SO_2	sulfur dioxide
SOFA	Separated Over-fire Air
ULSD	Ultra Low Sulfur Diesel

EXECUTIVE SUMMARY

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as "the prevention of any future, and the remedying of any existing, impairment of visibility…", and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved. RPGs are to be established for the final year in the planning period, which in the case of the first SIP is 2018.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The MANE-VU baseline year for the emission inventory is 2002 and for monitoring is 2000-2004. The next task is to identify key pollutants affecting visibility impairment at each Class I area. The major pollutant contributing to visibility impairment in MANE-VU has been shown to be sulfate.

In order to determine the key source regions and source types affecting visibility impairment at each Class I area, a contribution assessment was prepared by NESCAUM for MANE-VU. Major contributors were identified by ranking emissions sources, comparing Q/d (emission impact over distance), and modeling visibility impacts. Source apportionment and other analyses documented in MANE-VU's contribution assessment showed that several source categories have impacts on visibility at MANE-VU Class I areas.

The largest contribution to visibility impairment at most sites was from burning of coal, primarily utility and industrial combustion sources in MANE-VU and nearby States. At forested rural sites, biogenic organics are a moderate to large contributor to visibility impairment, but other sources of secondary organics also contribute. Wood smoke and ammonium nitrate were identified as small to moderate contributors.

Based on information from the contribution assessment and additional emissions inventory analysis, MANE-VU selected the following source categories for analysis in this project:

- Coal and oil-fired Electric Generating Units, (EGUs);
- Point and area source industrial, commercial and institutional boilers;
- Cement kilns;
- Lime kilns;
- The use of heating oil; and
- Residential wood combustion

This document presents the results of an analysis of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to reduce emissions from the above source categories in order to make reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

- Cost,
- Compliance timeframe,
- Energy and non-air quality environmental impacts, and
- Remaining useful life for affected sources.

The "four factor" analysis was applied to control options identified for each of the selected source categories. Cement kilns and lime kilns are analyzed together due to the similarity of the two source categories.

The table below presents a summary of the four factor analysis for the source categories analyzed. Detailed information on control technologies assessed in this effort is presented in the main body of this document.

Table I Summary of Results from the Four Factor Analysis

Source Category	Primary Regional Haze Pollutant	Average Cost in 2006 dollars (per ton of pollutant reduction)	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
Electric Generating Units	SO_2	IPM* v.2.1.9 predicts $775-$1,690 $170-$5,700 based on available literature	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, reduction in electricity production capacity, wastewater issues	50 years or more
Industrial, Commercial, Institutional Boilers	SO_2	$130-$11,000 based on available literature	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years
Cement and Lime Kilns	SO_2	$1,900-$73,000 based on available literature	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	$550-$750 based on available literature. There is a high uncertainty associated with this cost estimate.	Currently feasible. Capacity issues may influence timeframe for implementation of new fuel standards	Increases in furnace/boiler efficiency, Decreased furnace/boiler maintenance requirements	18-25 years
Residential Wood Combustion	PM and VOC	$0-$10,000 based on available literature	Several years - dependent on mechanism for emission reduction	Reduce greenhouse gas emissions, increase efficiency of combustion device	10-15 years

* Integrated Planning Model (IPM®) application by ICF for MANE-VU

This report also contains information on current and planned controls at 20 specific non-EGU sources and 30 specific EGU sources identified by MANE-VU to consider control strategies already in place or planned by 2018.

CHAPTER 1

INTRODUCTION

BACKGROUND

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as "the prevention of any future, and the remedying of any existing, impairment of visibility…", and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved. RPGs are to be established for the final year in the planning period, which in the case of the first SIP is 2018.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The MANE-VU baseline year for the emission inventory is 2002 and for monitoring is 2000-2004. The next task is to identify key pollutants affecting visibility impairment at each Class I area. The major pollutant contributing to visibility impairment in MANE-VU has been shown to be sulfate.

In addition to the planned reductions that will be included as part of the State SIPs for regional haze, federal programs will also have significant benefits in reducing regional haze by 2018 and beyond. A list of EPA's national and regional rules as well as voluntary programs that will assist in the reduction of fine particle pollution are as follows:

- Clean Air Interstate Rule (CAIR)
- The Acid Rain Program
- NO_X SIP Call
- 2004 Clean Air Nonroad Diesel Rule
- 2007 Clean Diesel Trucks and Buses Rule
- Tier 2 Vehicle Emission Standards and Gasoline Sulfur Program
- Emission standards for other engines (highway and non-highway use)
- National Clean Diesel Campaign
- The Great American Woodstove Changeout

More information and links to the programs listed above can be found on the following website: http://www.epa.gov/pm/reducing.html

DETERMINATION OF EMISSION SOURCE CATEGORIES AND INDIVIDUAL SOURCES MOST RESPONSIBLE FOR REGIONAL HAZE IN MANE-VU CLASS I AREAS

Particles in the $PM_{2.5}$ size range are directly responsible for visibility reduction. Figure 1.1 generated by NESCAUM from analysis of monitoring data shows the components of $PM_{2.5}$ mass at the seven Class I areas of concern on the 20% worst visibility days during the period from 2000-2004. These components of $PM_{2.5}$ are directly responsible for visibility reduction.

Figure 1.1

NESCAUM, 2006. "2000-2004 Visibility Rankings and Glide Paths.ppt." PowerPoint Presentation developed by Gary Kleiman.

From Figure 1.1, it is apparent that sulfate is the largest contributor to $PM_{2.5}$ mass at the Class I areas of concern. The second largest contributor to $PM_{2.5}$ mass is organic carbon (OC). Nitrates, elemental carbon (EC), soil, and sea salt also contribute to $PM_{2.5}$ mass.

Source apportionment and other analyses documented in MANE-VU's contribution assessment indicated that a number of source categories have impacts on visibility at MANE-VU Class I areas. The largest contribution to visibility impairment at most sites was SO_2 from coal-combustion, primarily utility and industrial sources in MANE-VU and nearby States. At forested rural sites, biogenic organics are a moderate to large contributor to visibility impairment but other sources of secondary organics also contribute. Wood smoke and ammonium nitrate were identified as small to moderate contributors (see Appendix B of the Contribution Assessment).

The contribution assessment also included an analysis of haze-associated pollutant emissions. "SO_2 is the primary precursor pollutant for sulfate particles. Sulfate particles commonly account for more than fifty percent of particle light extinction at northeastern Class I areas on the clearest days and for as much as or more than eighty percent on the haziest days." The assessment noted that point sources dominate SO_2 emissions in the MANE-VU region. Point source emissions sources primarily consist of stationary combustion sources for generating electricity, industrial power, and heat. Commercial and residential heating constitute another important source category in MANE-VU States. An analysis of the largest sources in the region also indicates that a few large kilns are among the largest SO_2 sources in the region.

Figures 1.2 and 1.3 show the top emissions source categories of $PM_{2.5}$ and SO_2 from Version 3 of the 2002 MANE-VU emissions inventory. The largest SO_2 source categories are the largest contributors to visibility impairment in MANE-VU.

Figure 1.2 MANE-VU 2002 Version 3 Annual Emissions Inventory Top $PM_{2.5}$ Primary Source Categories

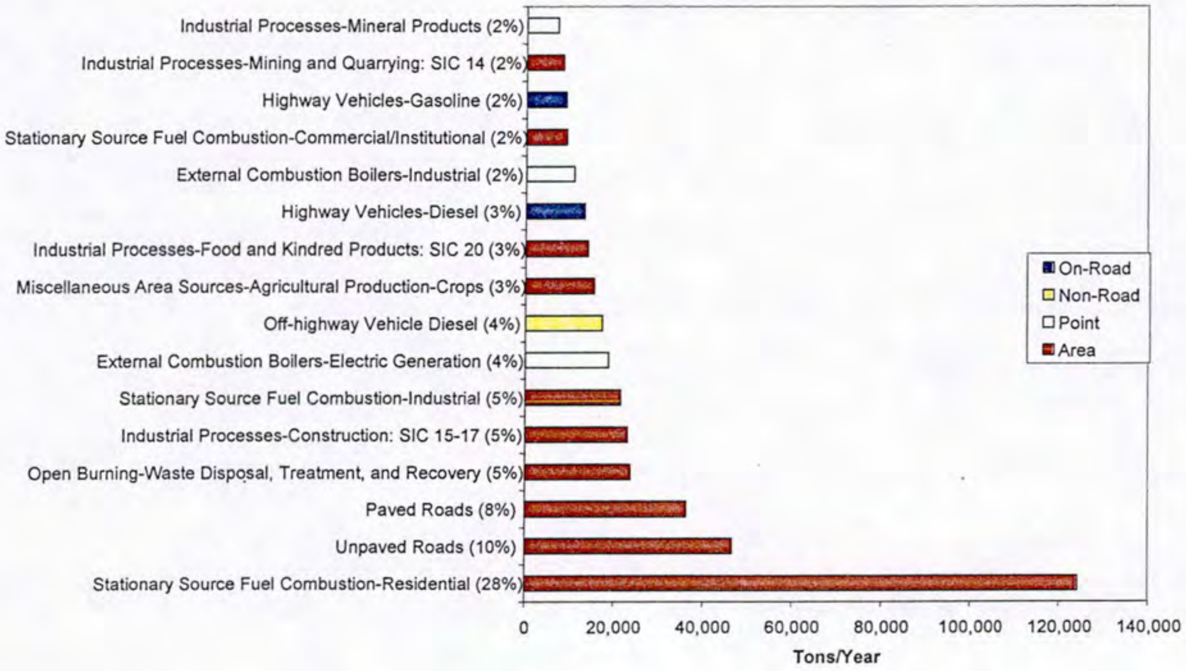
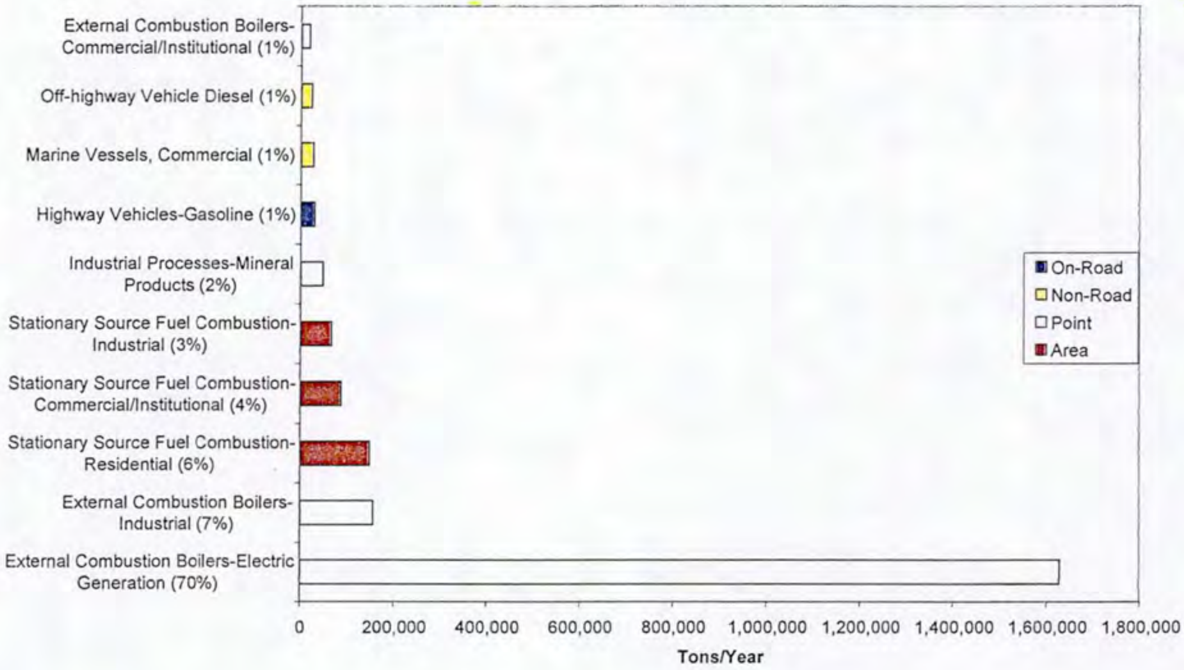


Figure 1.3 MANE-VU 2002 Version 3 Annual Emissions Inventory Top SO_2 Source Categories



Description of Individual Source Identification Process and Modeling

The following discussion describes the data and procedures that were used to identify the individual sources with the greatest impact on regional haze in MANE-VU Class I areas. The individual sources included in this report (see Chapters 3, 5, and 7) were determined by identifying the sources with the maximum predicted 24-hour sulfate ion impact.

From 2004 to 2006, the Vermont Department of Environmental Conservation (VTDEC) participated in MANE-VU RPO planning activities by performing regional scale screening modeling of pollutants known to contribute to regional haze at Class I areas in the MANE-VU region. The model used by VTDEC was the CALPUFF model run on a domain including most of the eastern United States. Both point and area sources were modeled for the entire year 2002, and variable hourly CEMS emission data were used for all the largest 750+ EGUs in the domain. Model results were primarily intended to be used in conjunction with other source/receptor modeling methods as part of the technical underpinning of the document, *Contributions to Regional Haze in the Northeast and Mid-Atlantic United States: Mid-Atlantic/Northeast Visibility Union (MANE-VU) Contribution Assessment*, prepared by NESCAUM for MANE-VU and dated August 2006. This document contains more detailed discussion of the approach used to develop inputs for the modeling platform, the model setup, and its validation. It can be found at the following link: http://www.manevu.org/Document.asp?fview=Reports#

Starting in 2006, through its participation on two MANE-VU RPO workgroups, (the BART Workgroup and the Reasonable Progress Workgroup), which were charged with developing technical support information for regional haze plans for the MANE-VU Class I areas, VTDEC made available some of the EGU source modeling results previously generated during its work on the contribution assessment report cited above. VTDEC also performed new point source modeling with the same CALPUFF modeling platform for a number of additional large point sources identified by the workgroups, primarily non-EGUs. The new point source modeling was performed for sources that did not have CEMS hourly emission data. This new modeling performed specifically for the workgroups differed in this fundamental way from the modeling of large EGUs with available CEMS hourly emission data which had been done for the contribution assessment. All new non-EGU point source modeling performed with CALPUFF by VTDEC for the BART and Reasonable Progress Workgroups utilized a constant average hourly emission rate (annual tons/8760) for the year 2002 based on emissions provided by the individual States in which the sources were located. Except for a more complete set of discrete receptors covering each Class I area, all other inputs and settings of the CALPUFF modeling system, including the NWS Observation-based CALMET created wind-fields, were exactly the same as used in the contribution assessment modeling work.

For the Reasonable Progress Workgroup, VTDEC assembled the results of its earlier individual CEMS-based stack modeling of EGUs into tables which listed the maximum 24-hr (calendar day) sulfate ion impact predicted at any receptor in each Class I area due to the emissions from each individual EGU modeled (more than 750). Because the largest contributing pollutant to visibility impairment in all the MANE-VU Class I areas is the sulfate ion, the Reasonable Progress Workgroup felt that ranking point sources based on this maximum 24-hour impact alone would be an appropriate way to prioritize their relative potential for improving visibility and making reasonable progress at these areas. Once the maximum 24-hr sulfate ion impacts modeled for 2002 were ranked from greatest to smallest by EGU, the top impacting EGUs were identified for each of the Class I areas.

In order to examine and prioritize potentially controllable non-EGU large point sources of SO_2 located both within MANE-VU and external to MANE-VU, the Reasonable Progress Workgroup examined the 2002 NEI based on SIC code selections. Selected stack points for sources selected were modeled individually using the stack parameters and the constant annual average emission rate of SO_2 only. VTDEC converted the annual total tons of SO_2 reported by the state to the NEI for that stack point into an average hourly emission rate and ran the CALPUFF model for the 194 largest points identified in three lists supplied by Delaware. The selection of points to model was based first on a selection of the top 100 emitting points modeled from a group of several hundred ICI boilers (list 1) and Cement and Lime Kilns (list 2) identified by SCC code and extracted from the 2002 NEI database. Later this list of 100 stack emission points to model was expanded by adding the top 94 stack points not previously included in the ICI and kiln lists, but identified by more inclusive selection criteria based on SCC codes (list 3) and ranked by annual SO_2 emissions.

The maximum predicted 24-hour sulfate ion impact from each of the 194 non-EGUs modeled were combined into an ordered table showing the largest impacting non-EGU at top and the least impacting non-EGU at the bottom for each Class I area. A similar ordered table was created showing the annual average sulfate ion impacts of these 194 non-EGU stack points. The top non-EGUs impacting each Class I area were then selected from the top of each list.

The ranked listings for EGUs represent the EGUs most likely to produce the largest sulfate ion impact at each Class I area on a 24-hour basis. The EGU modeled results were based on variable hourly SO_2 emissions from the CEMS data submitted by the sources themselves. For the EGUs, the modeled stack ID for which the hourly SO_2 emission was reported might be a single electric generating unit or it might be a combination of two or more individual electric generating units operating at a plant and emitting from the same stack. The CALPUFF modeling was done on the emission rate supplied for the particular hour of the year 2002 and did not determine whether that emission was from a single EGU or from a combination of several at a plant. Therefore, to identify which particular unit at a plant reporting multiple units emitting from a single stack is responsible for the specific impact due to that hourly emission, would require more information than was available to VTDEC. The reported impact is from the stack and the distribution among units combined in that stack's CEMs data cannot be determined from the modeling results.

For the non-EGU points modeled, there is a slight probability that emissions modeled may have been only from a particular "process" level in the NEI database structure. There may have been more than one process reported for the same emission point during the year 2002 so that a sum of two or more process annual emissions should be modeled and summed for the entire unit level emission control potential to be identified. The top modeled impacts are simply the top for each area based on the 194 separate stack points modeled with each individual annual average emission rate supplied from one of the three NEI selected listings VTDEC received.

APPROACH TO DEMONSTRATING REASONABLE PROGRESS

Based on the contribution assessment, including modeling and emissions inventory analysis, MANE-VU selected the following source categories for analysis in this project:

- Coal and oil-fired Electric Generating Units, (EGUs);
- Point and area source industrial, commercial and institutional boilers;
- Cement kilns;
- Lime kilns;
- The use of heating oil; and
- Residential wood combustion

This document presents the results of an analysis of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to demonstrate reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

- Cost,
- Compliance timeframe,
- Energy and non-air quality environmental impacts, and
- Remaining useful life for affected sources.

The "four factor" analysis is applied to control options identified for the selected source categories. The analysis of cement kilns and lime kilns was combined into one section due to the similarity of the two sources.

Category analyses are presented for electric generating units (EGUs), industrial, commercial, and institutional (ICI) boilers, cement kilns, lime kilns, distillate-oil fired heating units, and residential wood combustion. Only sulfur dioxide (SO_2) emissions are considered for the first five categories. The SO_2 emitted from sources in these five source categories comprised approximately 90% of all SO_2 emitted from within MANE-VU in 2002. For residential wood combustion, the analysis is presented for particulate matter. $PM_{2.5}$ emissions from this source were 28% of the total $PM_{2.5}$ emitted from within MANE-VU in 2002. Biomass burning causes both direct emissions of primary particles and emissions of volatile organics which can contribute to the formation of secondary organic carbon particles. Organic carbon is typically the second-largest contributor to regional haze in the MANE-VU region.

For EGUs, ICI boilers, and kilns control options include fuel switching, fuel preparation, *in-situ* modifications, and add-on controls. Because of the similarity in available control options, cement and lime kilns have been combined into one category. For oil-fired heating oil, the only control option considered is reduction in sulfur content in the fuel oil. For residential wood combustion and outdoor wood-fired boilers, we have included descriptions of alternative technologies for replacement and emission reduction.

Additionally, we have assembled current and planned controls for the 20 specific non-EGU and 30 EGU sources based on information from State agencies and Integrated Planning Model (IPM®). The purpose of selecting these sources is to find out whether the sources that have the greatest impacts on Class I areas near MANE-VU in 2002 are already controlled or will be controlled by 2018. In many cases, States have supplied a schedule of planned controls for these facilities, which we have included in tabular form in this report. In the case of EGUs, we obtained information from the States and from modeled projections developed using Integrated Planning Model (IPM®).

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Vermont Air Quality Planning. Personal communications regarding description of the source identification and modeling process from Paul Wishinski (802-241-3862, paul.wishinski@state.vt.us) via E-mail on April 4, 2007.

NESCAUM, 2006. *Contributions to Regional Haze in the Northeast and Mid-Atlantic United States*. Prepared by NESCAUM for MANE-VU, August, 2006.

CHAPTER 2

SOURCE CATEGORY ANALYSIS: ELECTRIC GENERATING UNITS (EGUs)

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that the principal contributor to visibility impairment in Class I MANE-VU areas and Class I areas affected by emissions from sources within MANE-VU is SO_2 from EGUs. Roughly 70% of the 2.3 million tons of SO_2 emissions in the 2002 emissions inventory (2002 MANE-VU Emissions Inventory Version 3) were from EGUs, making them the largest source category contributing to regional haze in terms of total visibility impairing emissions and in terms of number of facilities.

Boilers at EGUs burn various fuels to produce heat for steam production which is then used to drive turbine generators for electricity production. The primary fuel combusted in EGU boilers in the eastern United States is coal from mines in the Midwest and Appalachia. Coal from this region generally contains 2-4% sulfur. The sulfur contained in the coal is emitted as SO_2 from the boiler. Coal obtained from western States is generally lower in sulfur, with a sulfur content of <1%.

Nationally, 90% of the SO_2 emissions from the EGUs are from coal-fired electric utility boilers. These coal-fired utility boilers are also the largest sources of NO_X and PM emissions, which also contribute to regional haze. All coal-fired electric utility power plants in the United States use control devices to reduce PM emissions. Additionally, many of the boilers are required to use controls for SO_2 or NO_X emissions depending on site-specific factors such as the properties of the coal burned, when the power plant was built, and the area where the power plant is located. According to the EPA Clean Air Markets Division, (Personal communication with Mr. Peter Kokopeli, EPA – CAMD on April 3, 2007), as of January 1, 2006, the percentage of coal-fired EGU capacity in the United States with SO_2 and/or NO_X control devices (as a percentage of heat input), were as follows:

2% of coal-fired EGU capacity had SO_2 control only;
57% of coal-fired EGU capacity had NO_X control only;
32% of coal-fired EGU capacity had SO_2 and NO_X controls;
9% of coal-fired EGU capacity had no SO_2 or NO_X controls.

As 66% of coal-fired EGU capacity, (as a percentage of heat input), have no SO_2 controls, there is room for significant reductions in emissions of SO_2. There is currently a trend towards improving control of SO_2 through installation of additional controls and making other process and fuel changes. The four factor analysis of potential control scenarios for EGUs contained in this chapter addresses the control options and costs, time requirements, energy and non-air impacts, and source life associated with these controls.

Although PM and NO_X from coal-fired utility boilers contribute to regional haze, the MANE-VU contribution assessment conducted by NESCAUM determined that SO_2 from power plants was the largest contributor to regional haze in the MANE-VU Class I areas. Therefore, the focus of this control option analysis for coal-fired boilers is on SO_2 controls. Effects of the SO_2 control options on PM and NO_X emissions are addressed where applicable, to ensure that the impact on emissions of these pollutants is considered for planning purposes.

In addition to coal combustion, some EGUs in MANE-VU States also burn fuel oil and/or natural gas. However, the EGU sources with the greatest impact on MANE-VU Class I areas were all coal-fired units. Emissions of SO_2 from natural gas combustion are negligible, but SO_2 emissions from fuel oil combustion are directly proportional to the sulfur content of the fuel. The cost of switching from a high sulfur distillate fuel oil to a lower sulfur distillate fuel oil is addressed in Chapter 8 of this report.

The SCCs applicable to coal-fired utility boilers include SCCs beginning 1-01-001-XX, 1-01-002-XX, and 1-01-003-XX.

EVALUATION OF CONTROL OPTIONS

Effective post-combustion SO_2 controls for EGUs and particularly coal-fired boilers are well understood and have been applied to a large number of sources over the years in response to regulations in the form of NSPS, PSD/NSR, State RACT Rules and the Title IV Acid Rain Program. Additional SO_2 reductions are anticipated as a result of the Clean Air Interstate Rule (CAIR), which was finalized on May 12, 2005.

In addition to post-combustion controls that can be applied to reduce emissions of SO_2 from coal-fired boilers, there are other strategies that can be used to reduce emissions of SO_2. Examples of such strategies include switching to a fuel with a lower sulfur content, and coal cleaning prior to combustion. Methods of SO_2 control applicable to coal-fired boilers are listed in Table 2.1 with a brief description of the control option, applicability, and range of performance. A more detailed description of the control option and an analysis of the four factor assessment for reasonable progress follow the table.

MACTEC assembled the list of available SO_2 control options for the EGU source category given in Table 2.1 from available documentation. Note that the estimated performance of each control option varies greatly and depends on a variety of site specific factors, including the boiler type. Examples of three major types of coal-fired boiler include fluidized bed combustors, stoker boilers, and pulverized coal boilers. In addition to these three types of coal-fired boilers there are many subcategories of boilers, characterized by their specific design. Control devices designed for these types of boilers vary in terms of cost as well as estimated performance.

Table 2.1 SO_2 Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired EGUs currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired EGUs	Virtually eliminate SO_2 emissions by switching to natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired EGUs	20-25% reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	Applicable to all coal-fired EGUs	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references:

1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options, STAPPA-ALAPCO*, March 2006.

Switch to Low Sulfur Coal

Fuel switching encompasses several different control options. Often it is not possible to completely switch from one type of fuel to another. One option is blending lower-polluting fuels with baseline fuels to reduce overall emissions. For example, many coal-fired boiler operators blend lower sulfur subbituminous coals with high sulfur bituminous coals to reduce SO_2 emissions. In other cases, bituminous coals with a lower sulfur content can be substituted for high sulfur bituminous coal.

The feasibility of fuel switching depends partly on the characteristics of the plant and the particular type of fuel change being considered. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to subbituminous coal may present greater challenges and costs. In some instances, fuel switching will require significant investment and modifications to an existing plant. Switching to a lower sulfur coal can affect coal handling systems, boiler performance, PM control effectiveness and ash handling systems. In any case, fuel switching or blending has been a key strategy used by EGUs to comply with the federal Acid Rain Program. Overall SO_2 reductions estimated from switching to low-sulfur coal range from 50-80%.

Switch to Natural Gas

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions, but it is currently uneconomical to consider this option for base load EGUs due to the fuel quantity necessary and the price of natural gas. The price of natural gas and coal are variable, but in terms of heating value, the price of natural gas over the past several years has been several times higher than coal. According to information published on the EIA website, in January 2007 the price of natural gas was approximately four times higher than coal according to average monthly costs of fuel delivered to electricity producers during that month.

Coal Cleaning

According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, coal cleaning or washing is a widely practiced method of reducing impurities in coal, particularly sulfur. Reducing the sulfur content of the fuel used in the boiler reduces the SO_2 emissions proportionally. Coal cleaning has been shown to reduce SO_2 emissions by 20-25%, while increasing the heating value of the fuel. Additional removal can be achieved through advanced chemical washing techniques, but no detailed information on these techniques was available.

Conventional (physical) coal washing techniques remove ash and sulfur from coal by crushing the fuel and separating the components in a liquid bath, such as water. The lighter coal particles float to the top of the bath for recovery, while the heavier impurities sink to the bottom for removal.

Coal sulfur exists in two forms, inorganic and organic. The inorganic sulfur in coal called pyrite is primarily in the form of ferrous sulfate ($FeSO_4$). Because it is not chemically bound within the coal, 40-50% of this pyrite can be removed through coal washing. The organic form of sulfur is chemically bound in the molecular structure of the coal itself and cannot be physically washed out. Organic sulfur accounts for between 35-75% of the total sulfur in Illinois Basin coals in the example given by STAPPA-ALAPCO. Depending on the percentage of the sulfur in a given coal sample which exists in the form of pyrite, varying amounts of the total sulfur can be removed.

Although there are benefits associated with coal washing, there are limitations associated with this technology. The 20-25% SO_2 reduction is beneficial, but post-combustion controls have been shown to reduce SO_2 emissions by greater percentages. Also, solid and liquid wastes are generated using the washing process and must be addressed.

Flue Gas Desulfurization (FGD) - Wet

There are three types of FGD scrubbers: wet, spray dry, and dry. According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, EPA reports that 85% of the FGD systems in the

United States are wet systems. Twelve percent of the FGD systems are spray dry systems, and 3% are dry systems. The operating parameters, impacts on capacity factor, and costs of each SO_2 removal method are different. Capacity factor is the amount of energy a facility generates in one year divided by the total amount it could generate if it ran at full capacity.

SO_2 in the flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. These processes are called "wet FGD systems". Most wet FGD systems are based on using either limestone or lime as the alkaline source. At some of these facilities, fly ash is mixed with the limestone or lime. Several other scrubber system designs (e.g., sodium carbonate, magnesium oxide, dual alkali) are used by a small percentage of the total number of boilers.

The basic wet limestone scrubbing process is simple and is the type most widely used for control of SO_2 emissions from coal-fired electric utility boilers. Limestone sorbent is inexpensive and generally available throughout the United States. In a wet limestone scrubber, the flue gas containing SO_2 is brought into contact with limestone/water slurry. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge, mostly calcium sulfite hemihydrate and gypsum, is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct. Integrated Planning Model (IPM®) used by EPA to predict future EGU control strategies assumes that this technology will be used to control SO_2 from coal-fired boilers that are 100 MW or larger, that combust bituminous coal with 2% or higher sulfur content by weight. Integrated Planning Model (IPM®) documentation refers to the specific scrubber technology as Limestone Forced Oxidation, (LSFO), and assumes 95% SO_2 removal using this technology. Data and documentation obtained for use in this report are from Integrated Planning Model (IPM®) version 2.1.9.

The wet lime scrubber operates in a similar manner to the wet limestone scrubber. In a wet lime scrubber, flue gas containing SO_2 is contacted with hydrated lime/water slurry; the SO_2 is absorbed into the slurry and reacts with hydrated lime to form an insoluble sludge. The hydrated lime provides greater alkalinity (higher pH) and reactivity than limestone. However, lime-scrubbing processes require disposal of large quantities of waste sludge.

Another wet scrubber technology used to control emissions of SO_2 from EGUs is Magnesium Enhanced Lime, (MEL). This technology is available to coal-fired boilers from 100 MW to 550 MW in capacity, that combust bituminous, sub-bituminous or lignite coal with less than 2.5% sulfur content by weight. Integrated Planning Model (IPM®) assumes that MEL provides 96% SO_2 removal.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31-97%, with an average of 78%. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95%. For both types of wet scrubbers, operating parameters affecting SO_2 removal efficiency include liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of calcium sorbent to SO_2. Periodic maintenance is needed because of scaling, erosion, and plugging problems. Recent advancements include the use of additives or design changes to promote SO_2 absorption or to reduce scaling and precipitation problems.

Flue Gas Desulfurization (FGD) – Spray Dry

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubber) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). For the spray dryer absorber process, the combustion gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 to 180 °C (250 to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate sludge as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas, along with fly ash, and are collected in a PM collection device. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices, especially fabric filters. This process produces dry reaction waste products for easy disposal.

The primary operating parameters affecting SO_2 removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To increase overall sorbent use, the solids collected in the spray dryer and the PM collection device may be recycled. The SO_2 removal efficiencies of existing lime spray dryer systems range from 60-95%.

Lime Spray Drying (LSD) is a dry SO_2 scrubber technology applied in Integrated Planning Model (IPM®) runs for coal-fired boilers 550 MW or larger that combust bituminous, subbituminous or lignite coal with sulfur content between 0.4% and 2% sulfur by weight. Integrated Planning Model (IPM®) assumes that LSD provides 90% SO_2 removal.

Flue Gas Desulfurization (FGD) –Dry

For the dry injection process, dry powdered lime (or another suitable sorbent) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO_2 removal efficiencies of existing dry injection systems range from 40-60%.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EGUs

Each of the control options presented in Table 2.1 is evaluated in this section according to the four factors for determining reasonable progress as required by Section 169A(g)(1) of the Clean Air Act and 40 CFR 51.308(d)(1)(i)(A). The information provided in this section is intended to be used by the States in setting Reasonable Progress Goals for reducing regional haze in the MANE-VU Class I areas.

Cost of Compliance

For EGUs, EPA used Integrated Planning Model (IPM®) to predict which units will install controls at what costs and which units will buy credits. Integrated Planning Model (IPM®) predicts a least-cost solution to meet power production demands within emissions constraints. Emissions may be reduced by fuel-switching, use of controls or by using power from a cleaner unit. The RPOs made some Integrated Planning Model (IPM®) runs to determine which units will install controls to comply with the EPA CAIR rule. Additionally, MANE-VU investigated an even more stringent "CAIR Plus" strategy using Integrated Planning Model (IPM®). In Chapter 3, the parsed results (projections disaggregated to the unit level), available for the CAIR Plus strategy are used to help estimate costs for specific EGUs. It should be noted that Integrated Planning Model (IPM®) is an industry-wide model, and the control costs output from the model represent the industry-wide average cost of control that can be expected based on a set industry-wide emission reduction. Integrated Planning Model (IPM®) results can also be viewed as the predicted cost of control at a model plant. The costs of control at individual facilities are dependent on a number of factors and cannot be determined for any specific individual facility from Integrated Planning Model (IPM®) results.

Table 2.2 contains the marginal costs of SO_2 emission reductions, also known as the SO_2 allowance price, for MANE-VU Base Case CAIR, (MARAMA_5c), and CAIR Plus, (MARAMA 4c), Integrated Planning Model (IPM®) runs. These costs include the capital costs of new investments, fuel costs, and the operation and maintenance costs of power plants. For both the CAIR and CAIR Plus run, Integrated Planning Model (IPM®) installed scrubbers to meet the demand for SO_2 reduction while meeting the demand for electricity. Integrated Planning Model (IPM®) also installed NO_X controls, but the cost of achieving the NO_X emissions reductions was provided independently from SO_2 controls. Application of SO_2 controls such as use of cleaner and lower-sulfur coals or post combustion controls such as wet scrubbers generally help to reduce PM emissions in addition to SO_2. SO_2 controls generally do not affect PM or NO_X emissions.

Table 2.2 Marginal Costs of Emission Reductions (Allowance Prices) Calculated by Integrated Planning Model (IPM®) for the CAIR Base Case and CAIR Plus Runs (2006 $/ton)

Pollutant	CAIR Base Case (MARAMA_5c)						CAIR Plus Policy Case (MARAMA_4c)					
	2008	2009	2010	2012	2015	2018	2008	2009	2010	2012	2015	2018
SO_2	774	837	905	979	1,141	1,338	975	1,055	1,139	1,233	1,437	1,684

Table reference:
Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources; May 30, 2007.
Note – A conversion factor of 1.2101 was used to convert the dollar values from 1999 to 2006 www.inflationdata.com

The CAIR Plus strategy requires additional SO_2 and NO_X control beyond EPA's CAIR program. ICF's report on the CAIR and CAIR Plus Integrated Planning Model (IPM®) runs titled: *Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning*

Model (IPM®), states that the power sector opts for a technology strategy for complying with the CAIR Plus proposal requirements. In the CAIR Plus analysis, the CAIR Plus region requires the installation of an additional 19.5 GW of scrubbers and 77.8 GW of SCR by 2012. These controls represent a 30% increase in scrubbers and 185% increase in SCRs in 2012 compared to the Integrated Planning Model (IPM®) CAIR run. By 2018, the cumulative installation of scrubbers is 17% higher and the installation of SCR is 98% higher for the CAIR Plus run compared to the CAIR run. The resulting SO_2 and NO_X emissions from the CAIR and CAIR Plus Integrated Planning Model (IPM®) runs are listed for MANE-VU in Table 2.3.

Table 2.3 NO_X and SO_2 Emissions from the Electric Power Sector (Thousand Tons)

	2008 SO_2 | NO_X	2009 SO_2 | NO_X	2010 SO_2 | NO_X	2012 SO_2 | NO_X	2015 SO_2 | NO_X	2018 SO_2 | NO_X
CAIR Base Case (MARAMA_5c)	802 | 386	650 | 272	518 | 213	463 | 209	410 | 202	394 | 199
CAIR Plus Policy Case (MARAMA_4c)	735 | 376	556 | 228	396 | 159	376 | 162	312 | 153	271 | 146

Table reference:
Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources; May 30, 2007.

Cost of Switching to Low Sulfur Coal

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following two main reasons:

1. The cost of low-sulfur coal compared to higher sulfur coal
2. The cost of necessary boiler or coal handling equipment modifications

The cost of low-sulfur coal compared to higher sulfur coal is not only related to the "dollar per ton" cost of the coal, but also related to the heating value of the coal.

Recent data from the Energy Information Administration show the average price of coals from various locations together with estimated heating values and sulfur content. The prices of coal indicated in Tables 2.4 and 2.5 do not include the cost of delivery.

The energy-based cost of each of the coals listed in Table 2.4 is approximately the same, with the exception of coal from the Powder River Basin. Powder River Basin coal has a significantly lower heating value than the other four varieties of coal, but on an energy basis, it is still approximately one third the cost of the other coals listed. Since Powder River Basin coal contains significantly less sulfur, it would seem that this coal would be the best fuel for boilers trying to incorporate a lower sulfur coal. Unfortunately, due to the lower heating value of the coal, boilers that are configured to burn coal with a higher heating value can only use a small percentage of this low-sulfur coal (no higher than 15% Powder River Basin coal). The only way to burn higher percentages of the Powder River Basin coal would be to extensively retrofit the boilers or suffer from poor boiler performance and other operating difficulties. Such retrofits should be reviewed in light of current Prevention of Significant Deterioration (PSD) permitting regulations to ensure that all such requirements are met and that emissions do not increase. The coal prices included in Table 2.4 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Table 2.4 Recent Average Coal Prices from Various Locations in the U.S. (12/2006) ($/ton)

	Central Appalachia (Bituminous)	**Northern Appalachia (Bituminous)**	**Illinois Basin (Bituminous)**	**Powder River Basin (Subbituminous)**	**Uinta Basin (Low-S Bituminous)**
Coal Heating Value (BTU/lb)	12,500	13,000	11,000	8,800	11,700
Sulfur Content (%)	1.2	<3	5	0.8	0.8
Cost/ton ($)	$47.25	$43.00	$33.33	$9.85	$36.00

Table reference:
EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

The two types of coal used for fuel in EGU boilers in the United States are bituminous and subbituminous coals. Bituminous coals have varying amounts of sulfur, but the sulfur content of bituminous coal is generally higher than subbittuminous coal. Traditionally, many EGU boilers have been designed to combust bituminous coal because of the higher carbon content and heating value.

Table 2.5 shows the average 2005 cost data from the Energy Information Administration for bituminous and subbituminous coal. The purpose of this information is to demonstrate the difference in cost of these coals based on their heating value. Assuming a heat content for bituminous coal of 12,000 BTU/lb and 10,000 BTU/lb for subbituminous coal allows the calculation of the cost of the coal on an energy basis. The coal prices included in Table 2.5 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Table 2.5 Average U.S. Bituminous and Subbituminous Coal Prices (2006 dollars/ton)

Fuel	**Average Price per Ton**	**Average Price per MMBTU**
Bituminous Coal	$38.00	$1.58
Subbituminous Coal	$8.96	$0.44

Table reference:
EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
Note – A conversion factor of 1.0323 was used to convert the dollar values from 2005 to 2006
www.inflationdata.com

Switching to subbituminous coal can reduce SO_2 emissions by up to 80%, but changes must be made to the boilers to compensate for the lower heating value of the subbituminous coal. Much of the difference in fuel price is due to the difficulty in using subbituminous coal in boilers designed to combust bituminous coal. The 2006 STAPPA-ALAPCO document, *Controlling Fine Particulate Matter Under the Clean Air Act*, states that "fuel substitution is not feasible for sources where the substitution would require excessive retrofits or would entail substantial performance losses."

Cost of Coal Cleaning

The World Bank reports that the cost of physically cleaning coal varies from \$1 to \$10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases the costs were found to be between \$1 and \$5 per ton of coal cleaned. Based on the recent prices of coal from Tables 2.4 and 2.5, this cost represents a 2-15% increase in the cost of coal.

In addition to lowering the emissions from coal combustion, coal cleaning also increases the heating value of the fuel. This lowers the transportation cost of the fuel per unit of energy, offsetting the costs associated with the coal washing. It is not clear whether this has been taken into account in the cost information provided by the World Bank.

Cost of Flue Gas Desulfurization (FGD) – Wet

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with wet FGD is around \$410 per ton of SO_2 reduced when combusting high-sulfur coal. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 90%. Assuming the same boiler and SO_2 control efficiency, but firing low-sulfur coal, the cost per ton is slightly more expensive at \$510 per ton of SO_2 controlled. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

A similar cost estimation from the same STAPPA-ALAPCO document provides information for boilers in the size range of >4,000 MMBTU/hr (~ 1,200 MW) and <4,000 MMBTU/hr achieving >90% SO_2 removal efficiency. These cost estimates demonstrate the initial and ongoing costs of installing wet scrubbers. For units >1,200 MW, the capital costs are between \$380-\$850/MW; operation and maintenance costs (O&M) range from \$7-\$27/MW; and the ultimate cost effectiveness is shown to be from \$230-\$570/ton SO_2 removed. For boilers <1,200 MW, the capital costs are between \$850-\$5,100/MW; operation and maintenance costs (O&M) range from \$28-\$68/MW; and the ultimate cost effectiveness is shown to be from \$570-\$5,700/ton SO_2 removed. This information demonstrates a strong cost effectiveness advantage realized by installing control devices on the larger emission units. (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com)

In another independent analysis of control costs, Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Two wet scrubber (wet FGD) control technologies are discussed in Integrated Planning Model (IPM®)

background documentation; (1) Limestone Forced Oxidation (LSFO), and (2) Magnesium Enhanced Lime (MEL). Both of the scrubber control technologies are applicable to distinct unit sizes and coal types, but there is no indication in the parsed Integrated Planning Model (IPM®) results as to which type of scrubber has been applied by the model. Both scrubber technologies are assumed to achieve a SO_2 removal percentage of 95% or greater. According to Integrated Planning Model (IPM®) documentation, the costs used by Integrated Planning Model (IPM®) for these control technologies were developed by EPA and presented in a document titled *Emissions: A Review of Technologies*, (EPA-600/R-00-093), October 2000 prepared by EPA's Office of Research and Development. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. The range of various scrubber costs is included in Attachment 1. Using the data in Attachment 1 and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using these control technologies vary from approximately \$300-\$1,100 per ton of SO_2 removal, (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com).

Cost of Flue Gas Desulfurization (FGD) – Spray Dry

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with spray dry FGD is around \$420 per ton of SO_2 reduced. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 90%. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

EPA reports in a 2005 document titled *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*, that conventional Spray Dry FGD systems can cost from \$155-\$237 per kW, have fixed operation and maintenance costs ranging from \$1.55-\$7.25 per kW-yr, and variable operation and maintenance costs from 0.2-0.7 mills/kWh. These costs are associated with a 300 MW plant. (Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)

A similar cost estimation from STAPPA-ALAPCO, 2006 provides information for boilers in the size range of >2,000 MMBTU/hr (~600 MW) and <2,000 MMBTU/hr achieving from 80-90% SO_2 removal efficiency. These cost estimates provide the initial and ongoing costs of installing wet scrubbers. For units >600 MW, the capital costs are between \$140-\$510/MW; operation and maintenance costs range from \$14-\$34/MW; and the ultimate cost effectiveness is shown to be from \$170-\$340/ton SO_2 removed. For boilers <600 MW per hour, the capital costs are between \$510-\$5,100/MW; operation and maintenance costs (O&M) range from \$34-\$1,020/MW; and the ultimate cost effectiveness is shown to be from \$570-\$4,550/ton removed. As was the case with wet scrubbers, this information demonstrates a strong cost effectiveness advantage realized by installing control devices on the larger emission units. (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com)

Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type.

(http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Lime Spray Dry (LSD) technology is one form of SO_2 control applied by Integrated Planning Model (IPM®). LSD is assumed to achieve a SO_2 removal percentage of 90%. According to Integrated Planning Model (IPM®) documentation, the costs used by Integrated Planning Model (IPM®) for these control technologies were developed by EPA and presented in a document titled *Emissions: A Review of Technologies*, (EPA-600/R-00-093), October 2000 prepared by EPA's Office of Research and Development. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. The range of various scrubber costs is included in Attachment 1. Depending on boiler size, boiler capacity factor, and coal sulfur content, the fixed capital costs range from \$142 to \$183/kW, while fixed operation and maintenance costs (O&M) range from \$5 to \$7/kW-yr and variable O&M costs range from 1.9 to 2.4 mills/kWh. Assuming the typical costs in Attachment 1, an EGU rated 800 MW, a capital cost investment of \$156/kW or \$125 million would be expected. Fixed O&M and variable O&M costs would be approximately \$6/kW-yr and 2.2 mills/kWh respectively and would depend on the EGU annual output. This cost could be expected to reduce SO_2 emissions by 90%. The cost and performance calculations were primarily a function of heat rate, capacity, and sulfur content. Using the data in Attachment 1 and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using this control technology varies from approximately \$480-\$600 per ton of SO_2 removal, (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com).

Cost of Flue Gas Desulfurization (FGD) – Dry

The cost of flue gas desulfurization varies depending on a number of factors including the size of the boiler, SO_2 reduction requirements, boiler capacity factor, and fuel sulfur content. Taking these factors into account, the typical cost effectiveness of a 1,000 MMBTU/hr (~300MW) coal-fired boiler equipped with dry FGD is around \$693 per ton of SO_2 reduced when combusting high-sulfur coal. This cost is based on a boiler capacity factor of 83% and SO_2 removal efficiency of 40%. Assuming the same boiler and SO_2 control efficiency, but firing low-sulfur coal, the cost per ton is slightly higher at \$764 per ton of SO_2 controlled. (*Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006) (Converted from 2003 to 2006 dollars using a conversion factor of 1.0959 www.inflationdata.com)

The 2005 EPA document titled, *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*, shows that advanced dry FGD systems can cost from \$50-\$150 per kW, have fixed operation and maintenance costs ranging from <\$1 -\$3 per kW-yr, (based on 1-2% of capital), and variable operation and maintenance costs from 0.2-0.7 mills/kWh. Assuming an SO_2 reduction percentage of 40%, capacity factor of 85%, coal sulfur content of 1.5%, and coal heat content of 12,000 BTU/lb and applying a standard engineering economics analysis (Attachment 2), the costs of SO_2 removal using this control technology varies from approximately \$250-\$850 per ton (Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)).

Summary of SO_2 Reduction Costs

The cost of SO_2 reductions on a per ton basis for EGUs is dependent on the cost (and availability) of fuels, boiler size and type, equipment retrofit costs, the desired emission reduction, and other site specific factors. Although these factors can cause the cost of the reductions to be well above or below the industry average, a summary of estimated ranges for SO_2 reductions is included in Table 2.6 for FGDs. Sufficient data were not available to calculate a range of costs with reasonable certainty for fuel switching or coal cleaning. Within the range of estimated costs for a given boiler size, the low end of the SO_2 reduction cost is generally associated with a high boiler capacity factor. The reason for this is due to the high capital costs and fixed operation and maintenance costs of the control device. With higher boiler capacity factors, the control device is able to reduce more tons of SO_2, which effectively reduces the per ton cost of the reduction.

Table 2.6 Estimated Cost Ranges for SO_2 Control Options for Coal-fired EGU Boilers (2006 dollars/ton of SO_2 Reduced)

Technology	Description	Performance	Cost Range (2006 dollars/ton of SO_2 Reduced)
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal	Potential reduction in coal costs, but possibly offset by expensive retrofits and loss of boiler efficiency
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Virtually eliminate SO_2 emissions by switching to natural gas	Unknown – cost of switch is currently uneconomical due to price of natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	20-25% reduction in SO_2 emissions	2-15% increase in fuel costs based on current prices of coal
Flue Gas Desulfurization (FGD) – Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	30-95%+ reduction in SO_2 emissions	\$570-\$5,700 for EGUs <1,200 MW \$330-\$570 for EGUs >1,200 MW
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	60-95%+ reduction in SO_2 emissions	\$570-\$4,550 for EGUs <600 MW \$170-\$340 for EGUs >600 MW
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	40-60% reduction in SO_2 emissions	\$250-\$850 for EGUs ~300 MW

Table references:

1. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html
2. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
3. STAPPA-ALAPCO. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*; March 2006.

4. U.S. EPA. EPA-600/R-05/034; *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*; March 2005.
5. U.S. EPA. Integrated Planning Model (IPM®) background documentation located on website: http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html
6. *Final Draft Report - Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®), ICF Resources*; May 30, 2007.
7. World Bank Organization. Information located on website: http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/aqsocc.stm

Time Necessary for Compliance

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the previous Phase I of the NO_X SIP Call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase I of the NO_X SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a maximum of 2 years after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a maximum of 3 years is adequate for the installation of post combustion controls.

For post-combustion controls, site-specific information must be supplied to vendors in order to determine the actual time needed for installation of a given control. Large scale implementation of control devices within the EGU sector, particularly in a short time period, may require consideration of impacts on regional electricity demands. Integrated Planning Model (IPM®) has allowed for these and other impacts in determining the least cost approach to emission reductions, however, there is a great deal of uncertainty associated with modeled results in comparison to real-world applications of control strategies.

For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

Energy and Non-Air Impacts

Fuel switching and cleaning may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). Additionally, these SO_2 control methods can create fuel supply problems if several large customers of various types of coal suddenly make changes in purchasing patterns. The main impact would be on the stability of fuel prices. It is not likely that this would be a persistent problem.

Another impact of fuel switching is that the modifications required for switching from one fuel to another may require a unit to be examined for major NSR permitting requirements. This is true even for modifications required for addition of controls since the modifications could trigger the definition of a "significant modification" under NSR/PSD.

Fuel switching between types and geographic sources of coal and installation of control devices can significantly effect mercury emissions. Data from EPA's Mercury Information Collection Request (ICR) revealed that many power plants have existing mercury capture as a co-benefit of air pollution control technologies for NO_X, SO_2 and PM. This includes capture of particulate-bound mercury in PM control equipment and capture of soluble ionic mercury in wet FGD systems. Additional data have also shown that the use of SCR for NO_X control enhances oxidation of elemental mercury to the soluble ionic form, resulting in increased removal in the wet FGD system for units burning bituminous coal. Overall the ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous coal-fired plants. Other factors that influence mercury emissions from coal combustion are chlorine content of the coal and fly ash composition.

FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage. According to Integrated Planning Model (IPM®) background documentation, wet FGD systems reduce the capacity of the EGU by 2.1%. This means that the scrubber reduces the amount of electricity for sale to the grid by 2.1%. The main effect of this reduction is the increased cost of energy production.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Remaining Useful Life of the Source

Available information for remaining useful life estimates of EGU boilers indicates a wide range of operating lifetimes, depending on size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of regulations over the years has resulted in retrofitting that has ultimately increased the expected life span of many EGUs. The lifetime of an EGU may be extended through repair, repowering, or other strategies if the unit is more economical to run than to replace with power from other sources. This may be particularly likely if the unit serves an area which has limited transmission capacity available to bring in other power.

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CHAPTER 3

ANALYSIS OF SELECTED ELECTRIC GENERATING UNITS (EGUs)

EGU FACILITY CONTROLS

The Vermont Department of Environmental Conservation (VTDEC) used the CALPUFF model to estimate sulfate ion impacts from large EGUs and determine the major EGUs and process units (boilers) at the EGUs that contribute to visibility impairment in Class I MANE-VU areas and Class I areas affected by emissions from sources within MANE-VU (See Chapter 1, for more details). Modeling was based on 2002 SO_2 emissions, and the results of the modeling showed the SO_2 emissions of the 100 highest emitting EGUs and the contribution of these sources toward the SO_2 concentration in each of the Class I areas. Proximity of the individual sources to Class I areas and variations in meteorology on the 20% worst visibility days resulted in varying impacts from individual sources on each Class I area. In subsequent discussions with MARAMA and the Reasonable Progress Workgroup, MACTEC was directed to focus on the emissions from the top 30 individual sources for this analysis. The 30 individual sources are located at 23 distinct facilities. The location of the 23 EGU facilities of interest is included in Figure 3.1.

Since EGUs are the largest emitters of SO_2 in the United States and have the greatest impact on haze in the MANE-VU Class I areas, it is particularly useful to determine what controls have recently been applied at these facilities (since the 2002 emission inventory). Also important is information about controls that are currently being applied at facilities, or are planned for addition in the future.

MACTEC gathered information from two primary sources of data for analysis of controls to be applied at the 30 EGUs.

1. Integrated Planning Model (IPM®) results from the MANE-VU CAIR Plus (MARAMA 4c) run.
2. Information from State agencies with facilities in the list of the top 30 individual sources. We requested EGU permit information, information about SO_2 controls recently implemented or planned at the facility and any available information on BART, consent decrees, or other regulations that will impact EGU control devices.

The MANE-VU CAIR Plus model results represent an estimate of the additional controls that might be installed under a more stringent cap and trade program in the Eastern U.S. The comparison of this estimate to the known planned controls for these 30 key EGUs is intended to give an idea of whether a stricter cap would in fact result in great controls at these sources.

Figure 3.1

EGU Facilities with the Greatest Visibility Impacts in Mid-Atlantic North Eastern Class I Areas

Note: Some facilities are too close to differentiate on the map

INTEGRATED PLANNING MODEL (IPM®) ANALYSIS

For EGUs, EPA used the Integrated Planning Model (IPM®) to estimate which units will install controls at what costs and which units will buy credits. The RPOs also made some Integrated Planning Model (IPM®) runs to determine which units will install controls to comply with the EPA CAIR rule. Additionally, an even more stringent "CAIR Plus" strategy was investigated using the Integrated Planning Model (IPM®). The parsed results which include modeled control scenarios for individual EGUs were used to help determine costs for EGUs, and ultimately estimate the marginal cost of SO_2 reductions for the model planning years of 2009, 2012, and 2018.

MACTEC obtained information from the CAIR Plus Policy Case, (MARAMA_4c) for the years 2009, 2012, and 2018 for the 30 EGUs. The information obtained included unit design capacity, SO_2 emissions, assumed existing controls, and controls to be applied as calculated by the Integrated Planning Model (IPM®). The information was available for each of the individual years, (2009, 2012, and 2018). Also available were the resulting changes in design capacity due to controls, production output, or other factors from Integrated Planning Model (IPM®). The parsed model data do not supply specific design information pertaining to the scrubber size, costs, or other related information for individual units. It is only possible to determine the year that the scrubber is due to be installed on individual process units. Information from the CAIR Plus Integrated Planning Model (IPM®) run is included in Table 3.1. Integrated Planning Model (IPM®) projections in Table 3.1 are not intended to be interpreted literally, but only as an example of the least-cost results from one set of inputs to the model. Also, the controls applied by Integrated Planning Model (IPM®) may differ from planned controls at the facility. For information on planned controls at these facilities, please see Table 3.2

Table 3.1 Integrated Planning Model (IPM® version 2.1.9) CAIR Plus Projections for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

State	Facility ID	Facility	Primary Emissions Point Descriptions	Point #	2002 SO_2 Total (Tons)[1]	2018 SO_2 Total (Tons)[2]	SO_2 Reduction (2002-2018) (Tons/Year)[3]	% SO_2 Reduction (2002-2018)[3]	Design Capacity[4]	Existing Control[4]	MANE_VU CAIR Plus Projection[5]
TN	D03406C10	Johnsonville	Coal - wall fired; dry bottom boiler	10	108,789	46,000	63,000	58%	15,688 MMBTU	Cold-side ESP; LNB	SCR by 2012
OH	D028404	Conesville	Coal - tangential; dry bottom boiler	4	92,340	7,000	85,000	92%	764 MW	Cold-side ESP; LNB + OFA + BOOS	SCR and Scrubber by 2009
PA	D031361	Keystone	Coal - tangential; dry bottom boiler	1	87,709	5,000	83,000	94%	8,010 MMBTU	Cold-side ESP + SCR; LNB; OFA	Scrubber by 2009
OH	D02872C04	Muskingum River	Coal - cyclone; wet bottom boiler	4	24,484	1,000	23,000	96%	205 MW to 201 MW by 2012	Cold-side ESP; OFA	SCR and Scrubber by 2012
PA	D03179C01	Hatfield's Ferry	Coal - wall fired; dry bottom boiler	1	55,695	13,000	43,000	77%	5,766 MMBTU	Cold-side ESP + SNCR; LNB	None
OH	D02876C01	Kyger Creek	Coal - wall fired; wet bottom boiler	1	13,789	1,000	13,000	93%	13,789 MMBTU	Cold-side ESP + SCR; OFA	Scrubber by 2012
WV	D03935C02	John E. Amos	Coal - wall fired; dry bottom boiler	2	31,465	6,000	25,000	81%	7,020 MMBTU	Cold-side ESP + SCR; LNB	Scrubber
PA	D031362	Keystone	Coal - tangential; dry	2	62,890	4,000	59,000	94%	8,010 MMBTU	Cold-side ESP + SCR; LNB; OFA	Scrubber by 2009
IN	D01010C05	Wabash River	Coal - wall fired; dry bottom boiler	5	9,380	1,000	8,000	89%	95 MW	Cold-side ESP + Cyclone; LNB + OFA	SNCR by 2009
PA	D031491	Montour	Coal - tangential; dry bottom boiler	1	61,005	4,000	57,000	93%	744 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
NC	D080421	Belews Creek	Coal - wall fired; dry bottom boiler	1	57,848	3,000	55,000	95%	1,096 MW	Cold-side ESP + SCR; LNB	Mercury control
WV	D03948C02	Mitchell	Coal - wall fired; dry bottom boiler	2	29,532	6,000	24,000	80%	7,020 MMBTU	Cold-side ESP + SCR + Wet Scrubber; LNB	None
PA	D031222	Homer City	Coal - wall fired; dry bottom boiler	2	55,346	3,000	52,000	95%	6,792 MMBTU	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
PA	D031492	Montour	Coal - tangential; dry bottom boiler	2	50,441	4,000	46,000	92%	729 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
MD	D01571CE2	Chalk Point	Coal - wall fired; dry bottom boiler	2	23,537	2,000	22,000	92%	335 MW	Cold-side ESP; LNB	SCR and Scrubber by 2009
MI	D01733C12	Monroe	Coal - cell fired; dry bottom boilers	1 & 2	48,563	28,000	21,000	42%	770, 785 MW	Cold-side ESP + SCR; LNB	None
PA	D031221	Homer City	Coal - wall fired; dry bottom boiler	1	45,745	3,000	43,000	93%	607 MW	Cold-side ESP + SCR; LNB + OFA	Scrubber by 2009
NC	D080422	Belews Creek	Coal - wall fired; dry bottom boiler	2	45,236	3,000	42,000	93%	1,096 MW	Cold-side ESP + SCR; LNB	Mercury control
WV	D039432	Fort Martin	Coal - wall fired; dry bottom boiler	2	45,890	5,000	41,000	89%	4,634 MMBTU	Cold-side ESP + SNCR; LNB + OFA	Scrubber by 2012
WV	D039431	Fort Martin	Coal - tangential; dry bottom boiler	1	45,228	5,000	40,000	89%	4,460 MMBTU	Cold-side ESP + SNCR; LNB + OFA	Scrubber by 2012
WV	D039353	John E. Amos	Coal - wall fired; dry bottom boiler	3	44,030	9,000	35,000	80%	11,900 MMBTU	Cold-side ESP + SCR; LNB	Scrubber

Table 3.1 Integrated Planning Model (IPM® version 2.1.9) CAIR Plus Projections for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

State	Facility ID	Facility	Primary Emissions Point Descriptions	Point #	2002 SO_2 Total (Tons)[1]	2018 SO_2 Total (Tons)[2]	SO_2 Reduction (2002-2018) (Tons/Year)[3]	% SO_2 Reduction (2002-2018)[3]	Design Capacity[4]	Existing Control[4]	MANE_VU CAIR Plus Projection[5]
OH	D0283612	Avon Lake	Coal - wall fired; dry bottom boiler	12	41,872	6,000	36,000	86%	6,040 MMBTU	Cold-side ESP	Scrubber by 2009; SCR by 2012
VA	D037976	Chesterfield	Coal - tangential; dry bottom boiler	6	40,923	4,000	37,000	90%	6,650 MMBTU	Cold-side ESP; LNB + OFA	SCR and Scrubber by 2012
PA	D082261	Cheswick	Coal - tangential; dry bottom boiler	1	42,018	5,000	37,000	88%	550 MW	Cold-side ESP + SCR ; LNB + OFA	Scrubber by 2009
OH	D028281	Cardinal	Coal - cell fired; dry bottom boilers	1	39,894	2,000	38,000	95%	600 MW to 587 MW in 2012	Cold-side ESP + SCR; LNB	Scrubber by 2012
MD	D015731	Morgantown	Coal - tangential; dry bottom boiler	1	37,757	3,000	35,000	92%	570 MW	Cold-side ESP; LNB +OFA	SCR and Scrubber by 2009
OH	D028667	W H Sammis	Coal - wall fired; dry bottom boiler	7	33,720	3,000	31,000	91%	593 MW to 818 MW in 2012	Cold-side ESP + SNCR; LNB	Scrubber in 2009; Coal to IGCC in 2012
MD	D015732	Morgantown	Coal - tangential; dry bottom boiler	2	32,587	3,000	30,000	91%	570 MW	Cold-side ESP; LNB +OFA	SCR and Scrubber by 2009
MA	D016193	Brayton Point	Coal - wall fired; dry bottom boiler	3	19,451	3,000	16,000	85%	5,800 MMBTU	Cold-side ESP; LNB + OFA	SCR, Scrubber, Mercury Control by 2009
NJ	D023781	B L England	Coal - cyclone; wet bottom boiler	1	10,080	1,000	9,000	90%	129 MW	Cold-side ESP; + SNCR; OFA	None

Note: CEMS hourly data was used in the modeling of the emission units, not annual emissions. Also, a single emission unit at a generating plant may represent two or more emission units at that plant emitting from the same stack point. (Refer to the detailed explanation in the Introduction section of this report).

Table references:

1. 2002 SO_2 total for the emission point from RPO emission inventory
2. Integrated Planning Model (IPM®) CAIR Plus projected 2018 SO_2 total for the emission point (rounded to nearest 1,000 tons)
3. Approximate reduction in SO_2 emissions for 2018 Integrated Planning Model (IPM®) versus 2002 RPO emission inventory (rounded to nearest 1,000 tons)
4. Information from Integrated Planning Model (IPM®) and RPO emission inventories
5. Information from Integrated Planning Model (IPM®) CAIR Plus Scenario

Integrated Planning Model (IPM®) background documentation defines a range of control efficiencies, costs, and applicability based on unit size and coal type. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html) Three scrubber control technologies are discussed briefly in Integrated Planning Model (IPM®) background documentation; 1. Limestone Forced Oxidation (LSFO), 2. Magnesium Enhanced Lime (MEL) and 3. Lime Spray Dryer (LSD). Each of the three scrubber control technologies are applicable for distinct unit sizes and coal types, but there is no indication in the parsed Integrated Planning Model (IPM®) results as to which type of scrubber has been applied by the model. All three scrubber technologies are assumed to achieve a SO_2 removal percentage of 90% or greater. The range of various scrubber costs is included in Attachment 1. Depending on boiler size, boiler capacity factor, and coal sulfur content, the fixed capital costs range from \$140 to \$580/kW, while fixed operation and maintenance costs (O&M) range from \$5 to \$24/kW-yr and variable O&M costs range from 1.0 to 2.4 mills/kWh. Assuming the typical costs in Attachment 1, an EGU rated 500 MW, (the approximate average of the 30 units included in this analysis), a capital cost investment of \$216/kW or \$110 million would be expected. Fixed O&M and variable O&M costs would be approximately \$11/kW-yr and 2.0 mills/kWh, respectively and would depend on the EGU annual output. This cost could be expected to reduce SO_2 emissions by greater than 90%. A typical SO_2 reduction from a 500 MW unit (assuming a minimum of 90% reduction), based on the 30 units included in this analysis would be from 4,000 to 40,000 tons annually. (Converted from 1999 to 2006 dollars using a conversion factor of 1.2101 www.inflationdata.com)

INFORMATION OBTAINED FROM STATE AGENCIES

The 30 EGUs analyzed here are already subject to a variety of existing emission control requirements, including CAIR, BART, mercury controls, the NO_X SIP call, and EPA's acid rain control program. Therefore, it is expected that at least some of the 30 EGUs will already be adding control by 2018.

To investigate this possibility, MACTEC contacted State agencies with facilities in the list of the top 30 individual sources. We requested EGU permit information, information about SO_2 controls recently implemented or planned at the facility, and any available information on BART, consent decrees, or other regulations that will impact EGU control devices. The information we have obtained is included in Table 3.2.

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Johnsonville[1, 2, 3]	TN	108,789	Coal-fired Boilers 01-10 for steam & electricity generation. The units are pulverized coal, dry-bottom boilers without fly ash reinjection. Units 1-6 are Combustion Engineering tangentially-fired boilers. Units 7-10 are Foster Wheeler wall fired boilers. All boilers exhaust through a common stack.	43-0011-01-10	15,688 MMBTU/hr	ESP	Combustion of low-sulfur fuel (since 2002) SCR by 2018	2018 SO_2 emissions will be approximately 51,000 tpy
Conesville[4]	OH	92,340	Unit 4 Main Boiler - Combustion Engineering model 7868 pulverized coal-fired, dry-bottom boiler	B004	7,960 MMBTU/hr	ESP	FGD and SCR by 8/18/09	N/A
Keystone (aka Reliant Energy Northeast Mgmt/Keystone Power Plant)[5]	PA	87,709	Boiler 1 w/low NO_X burner	1 (031)	8,717 MMBTU/hr	Cold-side ESP SCR	FGD	Alternate operation: SCR System Boiler 1
Muskingum River[6]	OH	24,484	Unit 3 Main Boiler - Babcock and Wilcox model RB-248 (custom) coal-fired, cyclone boiler	B004	2,150 MMBTU/hr	ESP	None planned	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Hatfield's Ferry[5]	PA	55,695	Babcock & Wilcox Boiler #1 that burns bituminous coal (227 tons/hr) and No. 2 fuel oil (1,384 gal/hr)	1 (031)	5,766 MMBTU/hr	Cold-side ESP	FGD	N/A
Kyger Creek[6]	OH	13,789	Unit #1 Boiler- Babcock and Wilcox pulverized coal-fired, wet-bottom boiler	B001	1,850 MMBTU/hr	ESP	SCR, FGD operational by 1/01/09	N/A
John E. Amos[7,8]	WV	31,465	Dry-bottom wall-fired coal boiler	2	800 MW, 7,020 MMBTU/hr	ESP Low NO_X burners SCR	FGD (12/2008)	Vents through CS012
Keystone (aka Reliant Energy Northeast Mgmt/Keystone Power Plant)[5]	PA	62,890	Boiler 2 w/low NO_X burner	2 (032)	8,717 MMBTU/hr	Cold-side ESP SCR	FGD	Alternate operation: SCR System Boiler 2
Wabash (aka Duke Energy Indiana, Inc. - Wabash River Generating Station)[9, 10]	IN	9,380	Wall fired coal electric utility boiler (pulverized – dry bottom) constructed in 1956 using No. 2 fuel oil as ignition fuel	5	1,096.2 MMBTU/hr	Low- NO_X burner (NO_X) ESP (PM)	None	Stack is equipped with CEM for SO_2

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Montour (aka PPL Montour, LLC – Montour Steam Electric Station)[5]	PA	61,005	CE Boiler – Unit #1 that burns bituminous coal and No. 2 fuel oil	1 (031)	7,317 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Belews Creek (aka Duke Power's Belews Creek Plant)[11]	NC	57,848	Coal-fired electric utility boiler constructed in 1974	1	1,120 MW	None	Scrubbers (2008)	Expected rate under their compliance plan for the Clean Smokestacks Act is 0.150 lbs SO_2/MMBTU. Expected emissions SO_2 for 2013 and later is 5,512 tpy.
Mitchell[7, 12]	WV	29,532	Dry-bottom wall-fired coal boiler	2	800 MW, 7,020 MMBTU/hr	ESP Low NO_X burners	FGD (1/2007); SCR (4/2007)	Vents through CS012
Homer City (aka Homer City OL/Homer City Generation Station[13]	PA	55,346	Boiler No. 2 (Unit 2)	2 (032)	6,792 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Montour (aka PPL Montour, LLC – Montour Steam Electric Station)[5]	PA	50,441	CE Boiler – Unit #2 that burns bituminous coal and No. 2 fuel oil	2 (032)	1,239 MMBTU/hr	Cold-side ESP SCR	FGD	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Chalk Point[15, 16]	MD	23,537	Steam Unit 2 is a wall fired, dry bottom, supercritical boiler base loaded unit. The primary fuel is coal with natural gas and No. 2 oil used for ignition.	2	342 MW	Low NO_X burners ESP SACR LNBs & SOFA (NO_X)	SCR and FGD (2009/2010 timeframe)	Unit covered under the MD Healthy Air Act
Monroe (aka Detroit Edison – Monroe Power Plant)[16]	MI	48,563	4 cell burner boilers (Boiler Unit Nos. 1, 2, 3, and 4) constructed in the late 1960s (1968-1969) and modified in 1994	EG01 EG02 EG03 EG04	3,000 MW (total)	Dry wire ESP (SO_3) FGD (Units 3 & 4) @ 97% CE	May put scrubbers on Units 1 & 2 later	If additional scrubbers are added, a SO_2 reduction of 97% is anticipated
Homer City (aka Homer City OL/Homer City Generation Station[13]	PA	45,745	Boiler No. 1 (Unit 1)	1 (031)	6,792 MMBTU/hr	Cold-side ESP SCR	FGD	N/A
Belews Creek (aka Duke Power's Belews Creek Plant)[11]	NC	45,236	Coal-fired electric utility boiler constructed in 1975	2	1,120 MW	None	Scrubbers (2008)	Expected rate under their compliance plan for the Clean Smokestacks Act is 0.150 lbs SO_2/MMBTU. Expected emissions SO_2 for 2013 and later is 4,639 tpy.

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Fort Martin[7, 8]	WV	45,228	Tangentially-fired coal boiler	1	552 MW, 4,460 MMBTU/hr	ESP Low NO_X burners SNCR Trim	FGD (4Q 2009)	N/A
Fort Martin[7, 8]	WV	45,890	Wall-fired coal boiler	2	55 MW, 4,634 MMBTU/hr	ESP Low NO_X burners SNCR Trim	FGD (1Q 2010)	N/A
John E. Amos[7, 8]	WV	44,030	Dry-bottom wall-fired coal boiler	3	1,300 MW, 11,900 MMBTU/hr	ESP Low NO_X burners SCR	FGD (12/2007)	N/A
Avon Lake[6]	OH	41,872	Boiler #12 - Pulverized coal-fired, dry bottom, boiler	B012	6,040 MMBTU/hr	ESP	SCR and FGD operational by 2010	N/A
Chesterfield (aka Chesterfield Power Station)[17]	VA	40,923	Combustion Engineering tangentially-fired coal boiler equipped with startup burners	6 (ES-6A)	6,650 MMBTU/hr	SCR ESP Stage combustion coal burners	FGD (95% CE under construction, operational 2008)	The unit is restricted to burn 2,330,160 tons/yr of coal at an annual average heating value of 12,500 BTU/lbs
Cheswick (aka Cheswick Power Station)[18]	PA	42,018	Tangentially-fired "main" boiler that burns bituminous coal (primary fuel), natural gas, and synfuel	1	5,500 MMBTU/hr (coal & synfuel) 1,000 MMBTU/hr (NG)	Low NO_X burners SCR ESP w/flue gas conditioning (PM)	FGD (98% CE planned)	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Cardinal[6, 12]	OH	39,894	Unit 1 Main Boiler - Babcock and Wilcox, pulverized coal-fired, dry bottom, cell burner boiler	B001	527 MMBTU/hr	ESP	FGD (2/2008)	N/A
Morgantown[14, 15]	MD	37,757	Combustion Engineering, Inc., Unit Boiler No. 1 - steam generating coal-fired utility boiler installed in 1967 which primarily combusts Eastern Bituminous coal containing no more than 2% sulfur by weight and secondary fuel is No. 6 oil containing no more than 2% sulfur by weight	1 (F-1)	5,317 MMBTU/hr	ESP SO_3 injection Low NO_X burners	SCR and FGD (2009/2010 timeframe)	Stacks equipped with SO_2, NO_X, CO_2, and ultrasonic flow monitors. Unit covered under the MD Healthy Air Act.
W H Sammis[6]	OH	33,720	Coal Fired Boiler No.1 - Foster-Wheeler pulverized coal-fired, dry-bottom boiler	B007	1,822 MMBTU/hr	Fabric filter	ESP FGD operational 12/31/09 SNCR Operational 06/06	N/A

Table 3.2 Point Source Information for the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)[a]	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Morgantown[14, 15]	MD	32,587	Combustion Engineering, Inc., Unit Boiler No. 2 - steam generating coal-fired utility boiler installed in 1967 primarily combusts Eastern Bituminous coal w/ no more than 2% sulfur by weight and secondary fuel is No. 6 oil w/ no more than 2% sulfur by weight	1 (F-2)	5,317 MMBTU/hr	ESP SO_3 injection Low NO_X burners	SCR and FGD (2009/2010 timeframe)	Stacks equipped with SO_2, NO_X, CO_2, and ultrasonic flow monitors. Unit covered under the MD Healthy Air Act.
Brayton Point[19]	MA	19,451	Water tube boiler	3 (EU3)	5,655 MMBTU/hr	ESP w/flue gas conditioning (PCD-3)	Fuel sulfur content (2011) FGD (2011)	BART recommended controls for SO_2 are 95% control or 0.15 lb/MMBTU (coal), 0.33 lb/MMBTU (0.3% fuel sulfur limit) (oil)
B L England[20, 21]	NJ	10,080	Wet-bottom, cyclone coal boiler	1	129 MW	ESP SNCR	None	The facility will either close by 2012 or install scrubbers on all coal-fired units. One scrubber is already installed and the other unit would get a 95% CE –minimum, but unclear if this unit is already controlled.

[a] 2002 SO_2 total for the emission point from RPO emission inventory.

[1] Tennessee Department of Environment and Conservation, Division of Air Pollution Control. Personal communication regarding Johnsonville facility from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 1, 2007.

[2] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comment regarding Johnsonville facility received from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 30, 2007.

[3] MACTEC, Inc., "Documentation of the Base G 2002 Base Year, 2009 and 2018 Emission Inventories for VISTAS", January, 2007.

[4] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communications regarding Conesville facility from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mail on February 20 and 21, 2007.

[5] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Keystone, Hatfield's Ferry, and Montour facilities from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7, 2007.

[6] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communication regarding Muskingum, Kyger Creek, Avon Lake, Cardinal, and WH Sammis facilities from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mail on February 20, 2007.

[7] West Virginia Division of Air Quality. Personal communication regarding John. E. Amos, Mitchell, and Fort Martin facilities from Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) via E-mail on February 17, 2007.

[8] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding John E. Amos, Mitchell, and Fort Martin and facilities received from Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) via E-mail on March 30, 2007.

[9] Indiana Department of Environmental Management, Office of Air Quality. Personal communication regarding Wabash facility between Mr. Jay Koch (317-233-0581, JKOCH@idem.IN.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[10] Indiana Department of Environmental Management, Office of Air Quality. Personal communications regarding Wabash facility from Mr. Jay Koch (317-233-0581, JKOCH@idem.IN.gov) via E-mail on February 1 and 5, 2007.

[11] North Carolina Department of Environment and Natural Resources, Division of Air Quality. Personal communications regarding Belews Creek facility from Ms. Sheila Holman (919-715-0971, shelia.holman@ncmail.net) via E-mail on February 1 and 2, 2007.

[12] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Mitchell and Cardinal facilities received from Mr. David J. Long, P.E. of American Electric Power (614-716-1245, djlong@aep.com) via E-mail on March 29, 2007.

[13] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Homer City facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7 and 8, 2007.

[14] Maryland Department of the Environment. Personal communication regarding Chalk Point and Morgantown facilities from Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) via U.S. mail on February 9, 2007.

[15] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Chalk Point and Morgantown facilities received from Mr. Brian Hug (410-537-4125, bhug@mde.state.md.us) via E-mail on March 14, 2007.

[16] Michigan Department of Environmental Quality, Air Quality Division. Personal communication regarding Monroe facility from Ms. Teresa Walker (517-335-2247, walkertr@michigan.gov) via E-mail on February 7, 2007.

[17] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Chesterfield facility from Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) via E-mail on February 9, 2007.

[18] Allegheny County Health Department. Personal communications regarding Cheswick facility from Ms. Jayme Graham (412-578-8129, JGraham@achd.net) via E-mail on February 2, 2007.

[19] Massachusetts Department of Environmental Protection. Personal communications regarding Brayton Point facility from Mr. Donald Squires (617-292-5618, Donald.Squires@state.ma.us) via E-mail on February 2 and 7, 2007.

[20] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding B.L. England facility between Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[21] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding B.L. England facility from Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) via E-mail on February 1, 2007.

Table 3.3 presents a side by side comparison of the predicted control information from Tables 3.1 and 3.2. The existing control information available from Integrated Planning Model (IPM®) data was in disagreement with the information reported by the States for many of the EGUs. Since controls at the EGUs may have changed recently [since Integrated Planning Model (IPM® v.2.1.9)], Table 3.3 reports existing control information obtained from the States for this report. The information on proposed or planned controls obtained from the States reflects that 26 of the 30 EGUs included in this study plan to install SO_2 control (FGD/scrubber), or switch to a lower sulfur coal prior to 2018. SO_2 reduction estimates from the States were only available for some of the EGUs, but reflect a significant reduction in SO_2 for those units for which an estimate was supplied.

Regarding the control information from Integrated Planning Model (IPM®) CAIR Plus results, Integrated Planning Model (IPM®) predicts that 21 of the 30 EGUs will install SO_2 in the CAIR Plus scenario. Additionally, Integrated Planning Model (IPM®) predicts a reduction in SO_2 at all 30 EGUs included in this study, including the 9 units for which no SO_2 control is added. The SO_2 reductions estimated by Integrated Planning Model (IPM®) are said to be achieved through a number of compliance strategies in addition to control, such as fuel switching, plant retirements, plant dispatch, and new builds. Additional information on all Integrated Planning Model (IPM®) compliance strategies and well as information on NO_X reductions are available in Integrated Planning Model (IPM®) documentation available on EPA's website and in the ICF report titled: *Final Draft Report – Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®).*

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM®) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	Point #	2002 SO_2 (tons)	Existing Controls (based on information from State)	Facility/State Proposed/Planned Controls {% SO_2 reduction}	IPM® Predicted Controls (CAIR Plus) {% SO_2 reduction}
Johnsonville	TN	10	108,789	ESP	Low sulfur fuel since 2002; SCR by 2018 {53% reduction in SO_2}	SCR by 2012 {58% reduction in SO_2}
Conesville	OH	4	92,340	ESP	FGD and SCR by 8/18/09 {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
Keystone	PA	1	87,709	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {94% reduction in SO_2}
Muskingum River	OH	4	24,484	ESP	None planned {SO_2 reduction assumed 0%}	SCR and Scrubber by 2012 {96% reduction in SO_2}
Hatfield's Ferry	PA	1	55,695	Cold-side ESP	FGD {SO_2 reduction unavailable}	None {77% reduction in SO_2}
Kyger Creek	OH	1	13,789	ESP	SCR, FGD operational by 1/01/09 {SO_2 reduction unavailable}	Scrubber by 2012 {93% reduction in SO_2}
John E. Amos	WV	2	31,465	ESP; Low NO_X burners; SCR	FGD by 12/2008 {SO_2 reduction unavailable}	Scrubber {81% reduction in SO_2}

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM$^{\circledR}$) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	Point #	2002 SO_2 (tons)	Existing Controls (based on information from State)	Facility/State Proposed/Planned Controls {% SO_2 reduction}	IPM$^{\circledR}$ Predicted Controls (CAIR Plus) {% SO_2 reduction}
Keystone	PA	2	62,890	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {94% reduction in SO_2}
Wabash River	IN	5	9,380	Low NOX burners; ESP	None planned {SO_2 reduction assumed 0%}	SNCR by 2009 {89% reduction in SO_2}
Montour	PA	1	61,005	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {93% reduction in SO_2}
Belews Creek	NC	1	57,848	None	Scrubbers (2008) {90% reduction in SO_2}	Mercury control {95% reduction in SO_2}
Mitchell	WV	2	29,532	ESP; Low NO_X burners	FGD (1/2007); SCR (4/2007) {SO_2 reduction unavailable}	None {80% reduction in SO_2}
Homer City	PA	2	55,346	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {95% reduction in SO_2}
Montour	PA	2	50,441	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {92% reduction in SO_2}
Chalk Point	MD	2	23,537	Low NO_X burners; ESP; SACR LNBs & SOFA	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
Monroe	MI	1 & 2	48,563	Dry wire ESP; FGD	Possible addition of scrubbers {97% SO_2 reduction if controlled}	None {42% reduction in SO_2}
Homer City	PA	1	45,745	Cold-side ESP; SCR	FGD {SO_2 reduction unavailable}	Scrubber by 2009 {93% reduction in SO_2}
Belews Creek	NC	2	45,236	None	Scrubbers (2008) {90% reduction in SO_2 }	Mercury control {93% reduction in SO_2}
Fort Martin	WV	2	45,890	ESP, Low NO_X burners; SNCR Trim	FGD (4Q 2009) {SO_2 reduction unavailable}	Scrubber by 2012 {89% reduction in SO_2}
Fort Martin	WV	1	45,228	ESP, Low NO_X burners; SNCR Trim	FGD (1Q 2010) {SO_2 reduction unavailable}	Scrubber by 2012 {89% reduction in SO_2}
John E. Amos	WV	3	44,030	ESP, Low NO_X burners; SCR	FGD (12/2007) {SO_2 reduction unavailable}	Scrubber {80% reduction in SO_2}
Avon Lake	OH	12	41,872	ESP	SCR and FGD operational by 2010 {SO_2 reduction unavailable}	Scrubber by 2009; SCR by 2012 {86% reduction in SO_2}
Chesterfield	VA	6	40,923	SCR; ESP; Stage combustion burners	FGD operational 2008 {95% reduction in SO_2}	SCR and Scrubber by 2012 {90% reduction in SO_2}
Cheswick	PA	1	42,018	Low NOX burners; SCR; ESP w/flue gas conditioning	None {SO_2 reduction assumed 0%}	Scrubber by 2009 {88% reduction in SO_2}
Cardinal	OH	1	39,894	ESP	FGD (2/2008) {SO_2 reduction unavailable}	Scrubber by 2012 {95% reduction in SO_2}

Table 3.3 Comparison of Controls Predicted by Integrated Planning Model (IPM®) CAIR Plus Results versus Proposed/Planned Control Additions by the State/Facility (by 2018) at the Top 30 EGUs Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	Point #	2002 SO_2 (tons)	Existing Controls (based on information from State)	Facility/State Proposed/Planned Controls {% SO_2 reduction}	IPM® Predicted Controls (CAIR Plus) {% SO_2 reduction}
Morgantown	MD	1	37,757	ESP; SO_3 injection; Low NO_X burners	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {92% reduction in SO_2}
W H Sammis	OH	7	33,720	Fabric filter	ESP and FGD operational 12/31/09; SNCR operational 6/06 {SO_2 reduction unavailable}	Scrubber in 2009; Coal to IGCC in 2012 {91% reduction in SO_2}
Morgantown	MD	2	32,587	ESP; SO_3 injection; Low NO_X burners	SCR and FGD (2009/2010 timeframe) {SO_2 reduction unavailable}	SCR and Scrubber by 2009 {91% reduction in SO_2}
Brayton Point	MA	3	19,451	ESP w/flue gas conditioning (PCD-3)	Fuel sulfur content (2011); FGD 2011 {95% reduction in SO_2}	SCR, Scrubber, Mercury Control by 2009 {85% reduction in SO_2}
B L England	NJ	1	10,080	ESP;SNCR	Facility will either close or install scrubbers by 2012 {95% reduction in SO_2}	None {90% reduction in SO_2}

Table Reference: See full reference information for Integrated Planning Model (IPM®) and State agency contacts associated with Tables 3.1 and 3.2.

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Energy Information Administration (EIA). Information located on website: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html

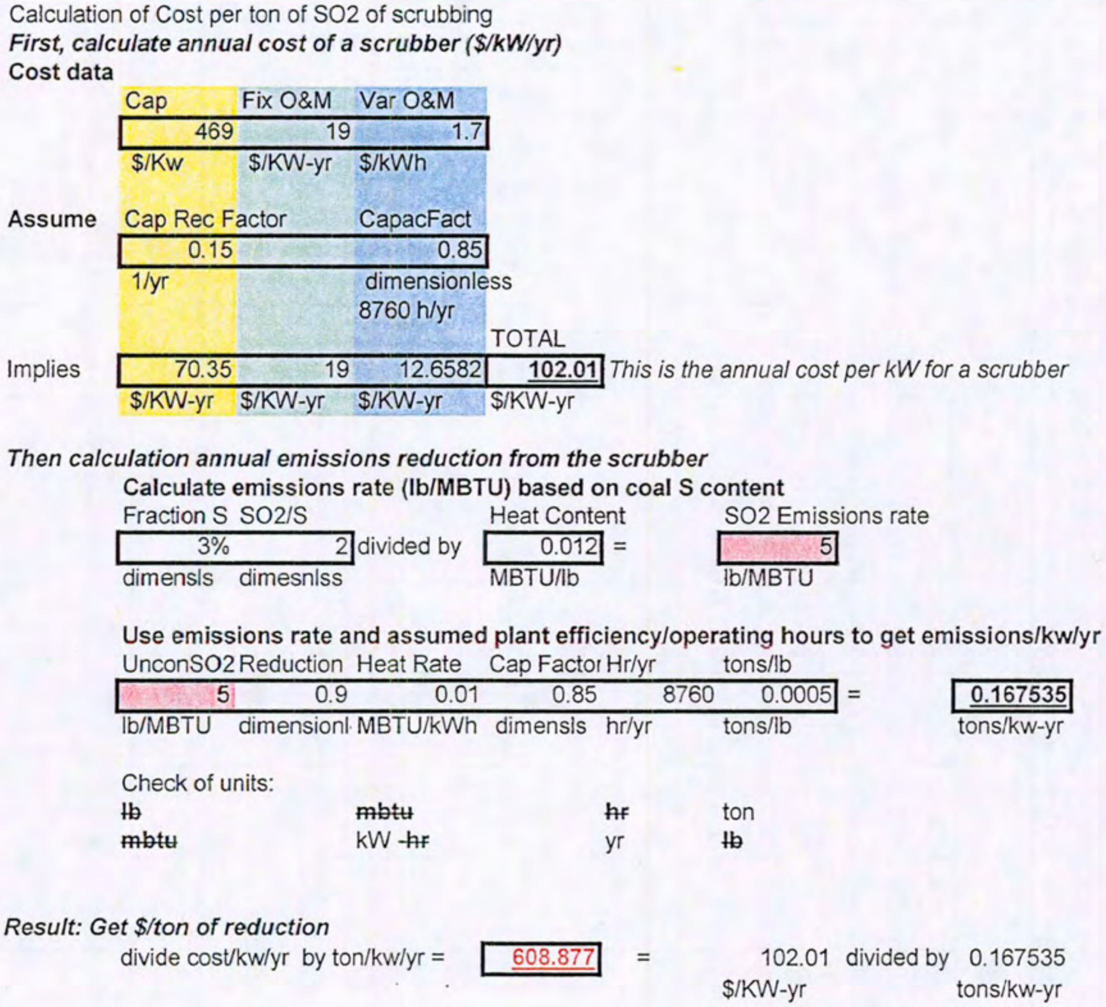
World Bank Organization. Information located on website: http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/aqsocc.stm

Attachment 1. Illustrative Scrubber Costs (1999 $) for Representative MW and Heat Rates under the Assumptions in EPA Base Case 2004

Scrubber Type	Capacity (MW)	Heat Rate (BTU/kWh)			Cost
		9,000	10,000	11,000	
LSFO Min. Cutoff: >= 100 MW Max. Cutoff: None Assuming 3.0% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	100	456	469	481	Cap.Cost ($/kW)
		19	19	20	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	300	225	234	243	Cap.Cost ($/kW)
		11	11	20	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	500	173	180	187	Cap.Cost ($/kW)
		9	9	9	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	700	142	149	155	Cap.Cost ($/kW)
		8	8	8	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
	1,000	157	166	174	Cap.Cost ($/kW)
		7	8	8	Fix. O&M $/kW-yr
		1.6	1.7	1.9	Var. O&M mills/kWh
MEL Min. Cutoff: >= 100 MW Max. Cutoff: <500 MW Assuming 1.5% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	100	340	351	362	Cap.Cost ($/kW)
		17	17	17	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	200	224	233	241	Cap.Cost ($/kW)
		12	12	12	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	300	224	235	245	Cap.Cost ($/kW)
		11	11	12	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	400	200	210	220	Cap.Cost ($/kW)
		10	10	10	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
	500	178	187	196	Cap.Cost ($/kW)
		9	9	9	Fix. O&M $/kW-yr
		0.8	0.9	1	Var. O&M mills/kWh
LSD Min. Cutoff: >= 550 MW Max. Cutoff: None Assuming 1.5% Sulfur Content Coal (by weight) with Heating Value of 11,900 BTU/lb	600	137	144	151	Cap.Cost ($/kW)
		5	5	6	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	700	127	134	140	Cap.Cost ($/kW)
		5	5	5	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	800	124	130	135	Cap.Cost ($/kW)
		5	5	5	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	900	125	131	137	Cap.Cost ($/kW)
		4	4	4	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh
	1,000	118	124	130	Cap.Cost ($/kW)
		4	4	4	Fix. O&M $/kW-yr
		1.6	1.8	2	Var. O&M mills/kWh

Table reference:Copy of Table 5.3 from EPA Integrated Planning Model (IPM®) documentation (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/bc5emission.pdf). (Note: To adjust cost data from 1999 to 2006, multiply by 1.2101 www.inflationdata.com

Attachment 2. Engineering Methodology Used to Calculate $/ton Pollutant Reduction



Calculation of Cost per ton of SO2 of scrubbing

First, calculate annual cost of a scrubber ($/kW/yr)

Cost data

	Cap	Fix O&M	Var O&M		
	469	19	1.7		
	$/Kw	$/KW-yr	$/kWh		
Assume	Cap Rec Factor		CapacFact		
	0.15		0.85		
	1/yr		dimensionless 8760 h/yr		
				TOTAL	
Implies	70.35	19	12.6582	**102.01**	*This is the annual cost per kW for a scrubber*
	$/KW-yr	$/KW-yr	$/KW-yr	$/KW-yr	

Then calculation annual emissions reduction from the scrubber

Calculate emissions rate (lb/MBTU) based on coal S content

Fraction S	SO2/S		Heat Content		SO2 Emissions rate
3%	2	divided by	0.012	=	5
dimensls	dimesnlss		MBTU/lb		lb/MBTU

Use emissions rate and assumed plant efficiency/operating hours to get emissions/kw/yr

UnconSO2	Reduction	Heat Rate	Cap Factor	Hr/yr	tons/lb		
5	0.9	0.01	0.85	8760	0.0005	=	**0.167535**
lb/MBTU	dimensionl	MBTU/kWh	dimensls	hr/yr	tons/lb		tons/kw-yr

Check of units:

~~lb~~	~~mbtu~~	~~hr~~	ton
~~mbtu~~	kW ~~-hr~~	yr	~~lb~~

Result: Get $/ton of reduction

divide cost/kw/yr by ton/kw/yr =	608.877	=	102.01	divided by	0.167535
			$/KW-yr		tons/kw-yr

CHAPTER 4

SOURCE CATEGORY ANALYSIS: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment has demonstrated that SO_2 emissions are the principal contributor to visibility impairment in Class I areas in the northeast. After electric generation units, Industrial, Commercial, and Institutional (ICI) boilers and heaters are the next largest class of pollution sources that contribute to SO_2 emissions. Typical industrial applications include chemical, refining, manufacturing, metals, paper, petroleum, food production and a wide variety of other small industries and commercial heating applications. Commercial and institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities. Most commercial and institutional boilers are small, with 80% of the population smaller than 15 million British Thermal Units per hour (MMBTU/hr). A fairly wide range of fuels are used by ICI boilers, ranging from coal, petroleum coke, distillate and residual fuel oils, natural gas, wood waste or other class of waste products. Boilers aggregated under the ICI classification are generally smaller than boilers in the electric power industry, and typically have a heat input in the 10 to 250 MMBTU/hr range; however, industrial boilers can be as large as 1,000 MMBTU/hr or as small as 0.5 MMBTU/hour.

The process that a particular unit serves strongly influences the boiler fuel choice. For example, the iron and steel industry uses coal to generate blast furnace gas or coke oven gas that is used in boilers, resulting in sulfur emissions. Pulp and paper processing may use biomass as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category. While many boilers are capable of co-firing liquid or gaseous fuels in conjunction with solid fuels, boilers are usually designed for optimum combustion of a single specific, fuel. Changes to the fuel type may, therefore, reduce the capacity, duty cycle, or efficiency of the boiler.

Boiler design also plays a role in the uncontrolled emission rate. Most ICI boilers are of three basic designs: water tube, fire tube, or cast iron. The fuel-firing configuration is a second major identifier of boiler design for solid fuels. Stoker boilers are the oldest technology and are still widely used for solid-fueled boilers. Pulverized coal boilers succeeded stokers as a more efficient method of burning coal and are used in larger boiler designs. Circulating fluidized bed (CFB) boilers are the most recent type of boiler for solid fuel combustion and are becoming more commonplace. CFB boilers are capable of burning a variety of fuels, and are more efficient and less polluting than stoker or pulverized coal boilers. Combined heat and power (CHP) or cogeneration technologies are also used to produce electricity and steam or hot water from a single unit. Some ICI boilers are used only in the colder months for space heating, while others have high capacity utilization year round.

Clean Air Act Regulations Controlling ICI Boilers

Emissions from ICI boilers are currently governed by multiple State and federal regulations under the Titles I, III, and IV of the Clean Air Act. Each of these regulatory programs is discussed in the following paragraphs. Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements includes Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air standards.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1998 to reflect improvements in control methods for the reduction of NO_X emissions. Subpart Db applies to fossil fuel-fired ICI units greater than 100 MMBTU per hour that were constructed or modified after June 19, 1984. Subpart Dc applies to fossil fuel-fired ICI units from 10 to 100 MMBTU per hour that were constructed or modified after June 9, 1989.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in non attainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings.

On September 13, 2004, EPA published a final rule under Title III of the CAA to substantially reduce emissions of toxic air pollutants from ICI boilers. These Maximum Achievable Control Technology (MACT) standards apply to ICI boilers located at major sources of hazardous air pollutants (HAPs). There are many options for complying with the MACT standards, ranging from continued use of existing control systems to fuel switching to the installation of a fabric filter and wet scrubber technologies. Thus, the control technologies used to reduce the level of HAP emitted from affected sources are also expected to reduce emissions of PM, and to a lesser extent, SO_2 emissions.

Title IV of the CAA addresses acid rain by focusing primarily on power plant emissions of SO_2. Title IV includes an Opt-in Program that allows sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own acid rain allowances. The Opt-in Program offers sources such as ICI boilers a financial incentive to voluntarily reduce its SO_2 emissions. By reducing emissions below allowance allocation, an opt-in source will have unused allowances, which it can sell in the SO_2 allowance market.

The regulation of ICI boilers by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, or MACT requirements. Overlaid on these unit level requirements are system-wide allowances of the NO_X SIP call and the Acid Rain SO_2 opt-in program. Thus, the specific emission limits and control requirements for a given ICI boiler vary and depend on boiler age, size, and geographic location.

EVALUATION OF CONTROL OPTIONS

An undesirable by-product of the combustion of sulfur, SO_2 is associated with the combustion of most fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Petroleum coke, a byproduct of the oil refining process, may have as much as 6% sulfur. Pipeline quality natural gas contains virtually no sulfur, while landfill gas may contain varying amounts of sulfur depending on the materials contained in the landfill. A variety of air pollution control technologies are employed to meet requirements for sulfur dioxide control and are dependant on a number of factors to determine which technique is utilized for a given facility.

Air pollution reduction and control technologies for ICI boilers have advanced substantially over the past 25 years. In addition, advances in power generation technologies, renewable energy, and energy efficiency have the potential to further reduce emissions from these facilities. The focus of this evaluation is on the first category mentioned above - emission control technologies. The timing and magnitude of reductions from the other strategies – improved technologies, demand reduction/energy efficiency, and clean power should be considered as part of a longer-term solution.

Control techniques may be classified into three broad categories: fuel treatment/substitution, combustion modification, and post-combustion control. Fuel treatment primarily reduces SO_2 and includes coal cleaning using physical, chemical, or biological processes. Fuel substitution involves burning a cleaner fuel or renewable fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is sometimes discussed in conjunction with post-combustion control technologies. Post-combustion control employs a device after the combustion of the fuel and is applied to control emissions of SO_2. It should be noted that physical or operational changes to a furnace or boiler may require that the unit be examined for applicability under the Prevention of Significant Deterioration (PSD) program.

There are a wide variety of proven control technologies for reducing SO_2 emissions from ICI boilers. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers.

Effective post-combustion SO_2 controls for boilers, and particularly coal-fired boilers, are well understood and have been applied to a number of sources over the years in response to regulations in the form of NSPS, PSD/NSR, State RACT Rules and the Title IV SO_2 program. Additional SO_2 reductions are anticipated as a result of regional pollution control initiatives prompted by the Clean Air Interstate Rule (CAIR), which was passed on May 12, 2005.

In addition to post-combustion controls that can be applied to reduce emissions of SO_2 from fossil fuel fired boilers, there are other strategies that can be used to reduce emissions of SO_2.

Examples of such strategies include switching to a fuel with a lower sulfur content, or coal cleaning prior to combustion. Methods of SO_2 control applicable to ICI boilers are listed in Table 4.1 with a brief description of the control option, applicability, and range of performance. After the table, a more detailed description of the control option and an analysis of the four factor assessment for reasonable progress is presented.

SO_2 Control Option Descriptions

Almost all SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. The exception to the nearly universal use of post-combustion controls is found in fuel switching and, more significantly, in fluidized bed boilers, in which limestone is added to the fuel in the combustion chamber.

Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability, performance and cost. Descriptions of available SO_2 control technology options are in Table 4.1. A brief discussion of these techniques follows.

Table 4.1 Available SO_2 Control Options For ICI Boilers

Technology	Description	Applicability	Performance
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired ICIs currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Switch to Natural Gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired ICIs	Virtually eliminate SO_2 emissions by switching to natural gas
Switch to a Lower Sulfur Oil	Replace higher-sulfur residual oil with lower-sulfur distillate oil. Alternatively, replace medium sulfur distillate oil with ultra-low sulfur distillate oil	Potential control measure for all oil-fired ICIs currently using higher sulfur content residual or distillate oils	50-80% reduction in SO_2 emissions by switching to a lower-sulfur oil
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired ICI boilers	20-25% reduction in SO_2 emissions
Combustion Control	A reactive material, such as limestone or bi-carbonate, is introduced into the combustion chamber along with the fuel	Applicable to pulverized coal-fired boilers and circulating fluidized bed boilers	40%-85% reductions in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	Applicable to all coal-fired ICI boilers	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references:

1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, March 2006.

Switch to Coal with Lower Sulfur Content

Switching from a high sulfur fuel to one with sufficiently low sulfur content is the first option available for SO_2 reduction in this category for pre-combustion control of SO_2. Fuels naturally low in sulfur content are readily available for solid (coal) and liquid (oil) fired boilers. For coal-fired boilers, low-sulfur fuels may be obtained directly or, alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources.

However, burning low-sulfur fuel may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a fuel with the required sulfur content to meet the applicable emission reduction may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a fuel is available, use of the lower-sulfur fuel that must be transported long distances from the supplier may not be cost competitive with burning higher sulfur fuel supplied by near-by suppliers and using a post-combustion control device. The feasibility of fuel switching depends partly on the characteristics of the plant and the particular type of fuel change being considered. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to sub-bituminous coal may present greater challenges and costs. In some instances, fuel switching will require significant investment and modifications to an existing plant. Switching to a lower sulfur fuel, either coal or oil, can affect fuel handling systems, boiler performance, PM control effectiveness and ash handling systems. Overall SO_2 reductions estimated from switching to low-sulfur fuels range from 50-80%.

Switch to Natural Gas

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions. It is technically feasible to switch from coal to natural gas, but it is currently uneconomical to consider this option for large ICIs due to the fuel quantity necessary and the price of natural gas. The price of natural gas is roughly seven times the price of coal in terms of heating value.

Reduced Sulfur Oil

Oil-fired boilers may opt for lower sulfur distillate fuels or, if available, ultra-low sulfur distillate fuel. Number 2 distillate fuel oil, heating oil, and highway diesel fuel oil are the same refinery-produced liquid, and are only differentiated for tax purposes. This differentiation is accomplished through addition of a red dye in the fuels supplied for non-transportation related use. Currently, the sulfur content in Number 2 oil varies between 15 and 20,000 ppm. Beginning in 2006, the permissible level of sulfur in highway diesel fuel (ultra low sulfur diesel, or ULSD) was reduced to15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur (Low Sulfur Diesel, or LSD). Consequently, refineries have already performed the capital investments required for the production of LSD and ULSD fuel oil. Based on EIA data for the week of Feb 23, 2007 domestic production of ULSD fuel oil accounted for about 45% of all distillate oil in the United States and LSD fuel oil accounted for slightly over 17% of domestic production (See Chapter 8).

Coal Cleaning

According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, coal cleaning or washing is a widely practiced method of reducing impurities in coal, particularly sulfur. Reducing the sulfur content of the fuel used in the boiler reduces the SO_2 emissions proportionally. Coal cleaning has been shown to reduce SO_2 emissions by 20-25%, while increasing the heating value of the fuel. Additional removal can be achieved through advanced chemical washing techniques, but no detailed information on these techniques was available.

Conventional (physical) coal washing techniques remove ash and sulfur from coal by crushing the fuel and separating the components in a liquid bath, such as water. The lighter coal particles float to the top of the bath for recovery, while the heavier impurities sink to the bottom for removal.

Although there are benefits associated with coal washing, there are limitations associated with this technology. The 20-25% SO_2 reduction is beneficial, but post-combustion controls have been shown to reduce SO_2 emissions by greater percentages. Also, solid and liquid wastes are generated using the washing process and must be addressed.

Combustion Control

SO_2 reduction is also possible through combustion related control technologies. One such technology that has been demonstrated and is currently available is the use of fluidized bed boilers.

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800° to 870° C (1500° F to 1600° F). The lower temperatures allow the use of limestone or dolomite to be added to the bed to capture sulfur. Limestone ($CaCO_3$) is converted to CaO at approximately 800° C (1500° F). SO_2 released from the fuel reacts with CaO to form $CaSO_4$, which is thermodynamically stable at bed temperatures. By recycling some of the solids leaving the bed up to 90% removal of SO_2 can be achieved with Ca/S molar ratios of 2 to 2.5 in circulating fluidized beds. Higher Ca/S ratios are required in bubbling beds. In either case, the sorbent is removed with the ash from the bed and sent to disposal.

Flue Gas Desulfurization (FGD)

There are three types of FGD scrubbers: wet, spray dry, and dry. According to the 2006 STAPPA-ALAPCO document on control technologies titled *Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*, EPA reports that 85% of the FGD systems in use in the United States are wet systems. Twelve percent of the FGD systems are spray dry systems, and 3% are dry systems. The operating parameters, efficiency, and costs of each SO_2 removal method are different.

SO_2 in the flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. These processes are called "wet FGD systems". Most wet FGD systems for control of SO_2 emissions are based on using either limestone or lime as the alkaline source. At some of these facilities, fly ash is mixed with the limestone or lime. Several other scrubber system designs (e.g., sodium carbonate, magnesium oxide, dual alkali) are used by a small number of boilers.

The basic wet limestone scrubbing process is simple and is the type most widely used for control of SO_2 emissions from coal-fired electric utility boilers. Limestone sorbent is inexpensive and generally available throughout the United States. In a wet limestone scrubber, the flue gas containing SO_2 is brought into contact with limestone/water slurry. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge, mostly calcium sulfite hemi-hydrate and gypsum, is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct.

The wet lime scrubber operates in a similar manner to the wet limestone scrubber. In a wet lime scrubber, flue gas containing SO_2 is contacted with hydrated lime/water slurry; the SO_2 is absorbed into the slurry and reacts with hydrated lime to form an insoluble sludge. The hydrated lime provides greater alkalinity (higher pH) and reactivity than limestone. However, lime-scrubbing processes require disposal of large quantities of waste sludge.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31-97%, with an average of 78%. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95%. For both types of wet scrubbers, operating parameters affecting SO_2 removal efficiency include liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of calcium sorbent to SO_2. Periodic maintenance is needed because of scaling, erosion, and plugging problems. Recent advancements include the use of additives or design changes to promote SO_2 absorption or to reduce scaling and precipitation problems.

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubbers) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). For the spray dryer absorber process, the combustion gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 to 180 °C (250 to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas, along with fly ash, and are collected in a PM collection device. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices, especially fabric filters. This process produces dry reaction waste products for easy disposal.

The primary operating parameters affecting SO_2 removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To increase overall sorbent use, the solids collected in the spray dryer and the PM collection device may be recycled. The SO_2 removal efficiencies of existing lime spray dryer systems range from 60-95%.

For the dry injection process, dry powdered lime (or another suitable sorbent such as trona) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO_2 removal efficiencies of existing dry injection systems range from 40 to 60%.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR ICI BOILERS

Each of the control options presented in Table 4.1 is reviewed in this section utilizing a four factor analysis approach for determining reasonable progress as required by Section 169A(g)(1) of the Clean Air Act and Section 51.308(d)(1)(i)(A). The information provided in this section is intended to be used by the States in setting Reasonable Progress Goals (RPGs) for reducing regional haze in Class I areas in MANE-VU Class I areas.

Cost of Compliance

To compare the various control options, information has been compiled on the cost-effectiveness of retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

Cost of Switching to Low Sulfur Coal, Distillate Oil, or Natural Gas

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following two main reasons:

1. The cost of low-sulfur coal compared to higher sulfur coal.
2. The cost of boiler or coal handling equipment modifications necessary

The cost of low-sulfur coal compared to higher sulfur coal is not only related to the "dollar per ton" cost of the coal, but the heating value of the coal also impacts the cost analysis.

Table 4.2 reflects the potential sulfur reduction possible by switching fuels:

Table 4.3 shows the average 2004 and 2005 cost data from the Energy Information Administration for various fuels.

Refineries were required to make significant capital investments to meet the LSD and ULSD highway fuel sulfur requirement. To achieve the LSD and ULSD sulfur goals, refineries were required to implement diesel desulfurization technologies. Estimates for the capital costs were developed in 2001 by the Energy Information Administration (EIA) and are based on calendar year 1999. Table 4.4 presents the capital costs for desulfurization technologies presented by the EIA. The EIA developed estimates for new and revamped desulfurization technologies at existing refineries.

Table 4.2 Potential SO_2 Reductions Through Fuel Switching

Original Fuel	Sub-bituminous Coal (% Reduction)	Distillate oil (% Reduction)	Natural Gas (% Reduction)
Bituminous Coal	72.9	91.2	99.9
Sub-bituminous coal	-	69.5	99.9
Residual Oil	-	91.5	99.9
Distillate Oil	-	-	99.7

Calculations based on typical fuel sulfur content listed in Department of Energy EIA analysis for 2000. *Energy Policy Act Transportation Rate Study: Final Report on Coal Transportation*

In its highway diesel fuel rulemaking, EPA also developed cost estimates for the deployment and implementation of desulfurization technologies at refineries. EPA estimated that it would cost existing refineries an estimated $50 million per refinery to install desulfurization technologies. No estimates were made for the costs associated with new refineries as none are currently being constructed in the United States. The EPA analysis spread the investment cost over a 2-year period. Consequently, it was estimated that the US refinery-wide investment for calendar year 2004 was $2.45 billion and $2.83 billion for calendar year 2005 (EIA 2001) (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com).

Using the most recently available EIA price information for 2006 No. 2 Distillate oil for industrial, commercial, and institutional facilities in the northeast (excluding taxes), a cost per ton of SO_2 removed was calculated to be $734/ton SO_2 by switching to 500 ppm LSD and $554/ton SO_2 by switching to ULSD fuel oils. (See the discussion of fuel oil prices in Chapter 7 – Heating Oil.)

Cost of Coal Cleaning

The World Bank, an organization which assists with economic and technological needs in developing countries reports that the cost of physically cleaning coal varies from $1 to $10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases the costs were found to be between $1 and $5 per ton of coal cleaned.

Cost of Combustion Control

Dry sorbent injection, (DSI), systems have lower capital and operation costs than post-combustion FGD systems due to: simplicity of design, lower water use requirements, and smaller land use requirements. Table 4.3 presents the estimated costs of adding DSI based SO_2 controls to ICI boilers based on boiler size, fuel type, and capacity factor. Capacity factor is the amount of energy a boiler generates in one year divided by the total amount it could generate if it ran at full capacity.

Table 4.3 Estimated Dry Sorbent Injection (DSI) Costs For ICI Boilers (2006 dollars)

Fuel	SO_2 Reduction (%)	Capacity Factor (%)	Cost Effectiveness ($/Ton of SO_2)		
			100 MMBTU/hr	250 MMBTU/hr	1,000 MMBTU/hr
2%-sulfur coal	40	14	4,686	3793	2,979
		50	1,312	1062	834
		83	772	624	490
3.43%-sulfur coal	40	14	2,732	2,212	1,737
		50	765	619	486
		83	450	364	286
2%-sulfur coal	85	14	2,205	1,786	1,402
		50	617	500	392
		83	363	294	231
3.43%-sulfur coal	85	14	1,286	1,040	818
		50	360	291	229
		83	212	171	134

Calculations based on information available from EPA Publications, EPA-452/F-03-034, *Air Pollution Control Technology Fact Sheet*, and EPA-600/R-05-034, *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*
(Converted from 2005 to 2006 dollars using a conversion factor of 1.0322 www.inflationdata.com)

Cost of FGD

Installation of post-combustion SO_2 control in the form of FGD has several impacts on facility operation, maintenance, and waste handling. FGD systems typically require significant area for construction of the absorber towers, sorbent tanks, and waste handling. The facility costs are, therefore, variable and dependent on the availability of space for construction of the FGD system. Solid waste handling is another factor that influences the cost of FGD control systems. Significant waste material may be generated that requires disposal. This cost may be mitigated, however, by utilization of a forced oxidation FGD process that produces commercial quality gypsum, which may be sold as a raw material for other commercial processes.

Table 4.4 presents the total estimated cost effectiveness of adding FGD based SO_2 controls to ICI boilers based on boiler size, fuel type, and capacity factor. There is no indication that these cost data include revenue from gypsum sales. Revenue from gypsum sales would reduce the cost of these controls.

Table 4.4 Estimated Flue Gas Desulfurization (FGD) Costs For ICI Boilers (2006 dollars)

Fuel	**Technology**	**SO_2 Reduction (%)**	**Capacity Factor (%)**	**Cost Effectiveness (\$/Ton of SO_2)**		
				100 MMBTU/hr	**250 MMBTU/hr**	**1,000 MMBTU/hr**
High-sulfur coal[a]	FGD (Dry)	40	14	3,781	2,637	1,817
			50	1,379	1,059	828
			83	1,006	814	676
Lower-sulfur coal[b]	FGD (Dry)	40	14	4,571	3,150	2,119
			50	1,605	1,207	928
			83	1,147	906	744
Coal	FGD (Spray dry)	90	14	4,183	2,786	1,601
			50	1,290	899	567
			83	843	607	407
High-sulfur coal[a]	FGD (Wet)	90	14	3,642	2,890	1,909
			50	1,116	875	601
			83	709	563	398
Lower-sulfur coal[b]	FGD (Wet)	90	14	4,797	3,693	2,426
			50	1,415	1,106	751
			83	892	705	492
Oil[c]	FGD (Wet)	90	14	10,843	8,325	5,424
			50	2,269	1,765	1,184
			83	1,371	1,079	740

a. Assumes sulfur content = 3.43% and ash content = 12.71%.
b. Assumes sulfur content = 2.0% and ash content = 13.2%.
c. Sulfur content of oil is not specified.

Table references:
Source: *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, STAPPA-ALAPCO, 2006.
Primary Reference: Khan, S. *Methodology, Assumptions, and References—Preliminary SO_2 Controls Cost Estimates for Industrial Boilers* (EPA-HQ-OAR-2003-0053-166), October-November 2003.
(Converted from 2004 to 2006 dollars using a conversion factor of 1.0672 www.inflationdata.com)

Time Necessary for Compliance

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the previous Phase I of the NO_X SIP Call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the NO_X SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a three year period for the installation of post combustion controls.

For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

Refiners in the United States are already producing low sulfur diesel fuel which may be marketed as distillate oil. There is a potential that offshore refiners may not be able to produce enough 15 ppm sulfur for export to the Northeast United States to meet peak demand, but so far this has not occurred.

ICI boilers would not have to retrofit or install expensive control technology to burn ULSD distillate fuel oil, therefore, compliance with the standard is driven by supply and demand of the lower sulfur distillate oils.

For combustion based and post-combustion based engineering and construction leads times will vary between 2 and 5 years depending on the size of the facility and specific control technology selected.

Energy and Non-Air Impacts

Fuel switching and cleaning do not significantly affect the efficiency of the boiler but may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Reducing the sulfur contents of distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by the New York State Energy Research and Development Authority, (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (Batey and McDonald 2005)

Remaining Useful Life of the Source

Available information for remaining useful life estimates of ICI boilers indicates a wide range of operating time, depending on size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range from about 10 years up to over 30 years.

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CHAPTER 5

ANALYSIS OF SELECTED INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

Modeling of visibility impacts on Class I regions was conducted by the Vermont Department of Environmental Conservation (VTDEC) and MANE-VU to identify the major ICI sources contributing to visibility impairment in the northeast. Table 5.1 lists the ICI sources identified to contribute significant levels of SO_2 to the MANE-VU region. MACTEC was directed by MARAMA and the Reasonable Progress Workgroup to focus on the 17 major sources listed in Table 5.1.

As explained in the previous chapter, there are a wide variety of proven control technologies for reducing SO_2 emissions from ICI boilers and specifically the control method for SO_2 applied to any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers.

INFORMATION OBTAINED FROM STATE AGENCIES

For the selected ICI boilers, MACTEC contacted State and or regional regulatory agencies to evaluate the status of each unit and determine if additional pollution controls had been mandated as a part of regulatory actions taken since the data used for the visibility impairment modeling were collected. Table 5.1 presents the information obtained from the States.

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Motiva Enterprises LLC – Delaware City[1]	DE	29,747	Fluid Coking Unit (FCU) and FCU Carbon Monoxide Boiler	002	57,199 barrels per day of total feed	None	Cansolv Regenerative Wet Gas Scrubber and SNCR	Data from Permit APC-82/0829 Amendment 5 SO_2 permit limit is 174 tpy
			Fluid Catalytic Cracking Unit (FCCU) and FCCU Carbon Monoxide Boiler	012	FCCU coke burn rate limit is 56,000 lbs/hr	None	Cansolv Regenerative Wet Gas Scrubber	Data from Permit APC-82/0981 Amendment 6 SO_2 permit limit is 361 tpy

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Kodak Park Division[2, 3]	NY	23,508	Building 31 and 321 stationary combustion installations, including package ABD built up boilers used for the generation of process steam and electricity . Boilers: 1 – Package boiler, No. 6 2 – Package boiler, No. 6 3 – Package boiler, No. 6 4 – Package boiler, No. 6 13 – Underfed stoker, coal 14 – Underfed stoker, coal 11 – Underfed stoker, coal 12 – Underfed stoker, coal 15 – Wet bottom cyclone, coal/No. 6 16 – Wall-fired, coal/No. 6 41 – Wet bottom cyclone, coal/No. 6 42 – Wet bottom cyclone, coal/No. 6 43 – Wet bottom cyclone, coal/No. 6 44 – Tangential-fired pulverized coal, coal/No. 2	U0015 Boilers (EP-031B-1): 1 2 3 4 13 14 Boilers (EP-031B-2): 11 12 15 16 Boilers (EP-321B-3): 41 42 Boilers (EP-321B-4): 43 44	98 MMBTU/hr 98 MMBTU/hr 98 MMBTU/hr 98 MMBTU/hr 265 MMBTU/hr 265 MMBTU/hr 197 MMBTU/hr 222 MMBTU/hr 478 MMBTU/hr 544 MMBTU/hr 500 MMBTU/hr 500 MMBTU/hr 640 MMBTU/hr 670 MMBTU/hr	None	BART analysis - NO_X & SO_2 controls affordable on Boilers 41, 42, & 43 Wet scrubber (90% reduction) would be ~\$2,150/ton Dry scrubber (40% reduction) would be ~\$1,850/ton	Process K07 (Bldg 31) is No. 6 fuel oil combustion in package boilers Process K09 (Bldg 31) is bituminous coal combustion in built up Boilers 13 and 14 Process K10 (Bldg 31) is No. 6 fuel oil combustion in built up Boilers 15 and 16 Process K11 (Bldg 31) is bituminous coal combustion for built up Boiler 15 Process K12 (Bldg 321) is No. 6 fuel oil combustion for built up Boilers 41, 42 and 43 Process K13 (Bldg 321) is bituminous coal combustion for built up Boilers 41, 42 and 43 Process K14 (Bldg 321) is No. 2 fuel oil combustion with NSPS applicability in Boiler 44 Process K15 (Bldg 321) is bituminous low sulfur coal combustion

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
MW Custom Papers LLC – Chillicothe Mill[4]	OH	23,216	No.5 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-40), capable of running on #2 fuel oil as backup fuel	B001	380 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input
			No.7 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-405), capable of running on #2 fuel oil as backup fuel	B002	422 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input
			No.8 Coal Boiler - wet bottom, pulverized coal-fired boiler (C. E. model VU-40), capable of running on #2 fuel oil as backup fuel.	B003	505 MMBTU/hr maximum heat input	Cyclone/ multi-clone ESP	None	9.9 lbs of sulfur dioxide per MMBTU actual heat input

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Eastman Chemical Company[5, 6]	TN	22,882	Two fuel burning installations (B-83-1 & B-253-1) w/a total of 19 coal fired boilers of which 14 units (#18-#24) are located at Powerhouse B-83-1 & 5 units (#25-#29) are located at Powerhouse B-253-1. The primary fuel is coal. In addition, wood, waste solids, waste liquids, & biosludge may be burned in these Powerhouses, while NG & process gas may also be burned in the Powerhouse B-253-1 boilers.	82-0003-01-19 (020101, 021520)	6,625 Million BTU/hr nominal heat input	ESP	Scubbers potentially	The five boilers in Powerhouse B-253-1 are subject to BART. The State does not have confirmation yet, but they believe that the boilers will be controlled by scrubbers of some sort. Units #11-#17, that were located at Powerhouse B-83-1, have been removed
			Coal-Fired Boilers 30 and 31	PES B-325-1or 82-1010-15 (261501)	Heat input is limited to 780 and 880 MMBTU/hr, respectively, on a 30 calendar day rolling average basis	None	None	
Westvaco Fine Papers[7, 8]	MD	19,083	Boiler 24 is a coal fired-cyclone boiler	1	590 MMBTU/hr maximum heat input	SNCR (NO_X) ESP (PM)	Baghouse (PM)	Not BART eligible due to age

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
			Boiler 25 is a coal fired-tangential boiler	2	785 MMBTU/hr maximum heat input	Low NO_X burners/ overfired air (NO_X) ESP (PM)	Scrubber (FGD in design) SNCR (NO_X) Baghouse to replace ESP (PM)	BART eligible
PPG Industries Inc.[9]	WV	12,678	Boiler 3 is a coal-fired boiler installed in 1942 and modified in 1981	R011 (002) or S076	243 MMBTU/hr	Fabric filter Low NO_X burners	None	Not BART eligible
			Boiler 4 is a coal-fired and natural gas-fired boiler installed in 1952	R015 (001) or S076	496 MMBTU/hr	ESP Low NO_X burners	None	Not BART eligible
			Boiler 5 is a coal-fired boiler installed in 1966	R072 (003) or S482	878 MMBTU/hr	ESP Low NO_X burners	None	BART eligible, facility to decrease emissions by using low-sulfur coal and taking an emission limit of 1,478.8 lb SO_2/hr

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Williams Ethanol Services Inc.[10, 11]	IL	12,244	4 boilers Boiler A & B are coal-fired boilers constructed in 1944 Boiler C is a coal/oil supplemental-fired boiler constructed in 1958 Boiler D is a NG/No. 2 oil-fired boiler constructed in 1976	10	Boilers A & B: 242 MMBTU/hr Boiler C: 330 MMBTU/hr Boiler D: 195 MMBTU/hr	Boilers A & B: Multi-cyclone Boiler C: ESP Boiler D: None	None	Not BART eligible. There is also a steep acid preparation system (Unit 2) that converts sulfur into sulfurous acid that will be used for the steeping process. Total sulfur usage for this unit is limited to 961,750 lbs/yr (at least 48% of the sulfur added to steepwater shall be retained in the products shipped from the plant).

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Corn Products International Inc.[10, 11]	IL	9,281	Utilities: Coal fired Boilers #1, #2, & #3 (pre 1972) Natural gas-fired Boilers #4 & #5 (pre 1972) Natural gas-fired Boiler #6 constructed in 1992 2 natural gas-fired turbines constructed in 1995	Group 9	Boilers #1, #2, & #3: 250 MMBTU/hr Boilers #4 & #5: 312.5 MMBTU/hr Boiler #6: 600 MMBTU/hr Turbines: 65 MMBTU/hr	Boilers #1, #2, & #3: ESP Boilers #4 & #5: None Boiler #6: low-NO_X burner & flue gas recirculation Turbines: None	None	Not BART eligible
Mead Westvaco Packaging Resource Group[12]	VA	8,552	Four (4) boilers #6 – primarily coal-fired #7 – coal/bark/wood-fired #8 - coal/bark/wood-fired #9 – primarily coal-fired	25	550 MMBTU/hr 440 MMBTU/hr 580 MMBTU/hr 807 MMBTU/hr	ESP Scrubbers FGR LNB	None	
PH Glatfelter Co./Spring Grove[13, 14]	PA	7,855	#4 Power Boiler that burns bituminous coal (13 tons/hr), #6 oil (751 gal/hr), & #2 oil (108 gal/hr)	034	363.7 MMBTU/hr	Cyclone dust collector ESP	None	Not BART eligible

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
			#5 Power Boiler that burns bituminous coal (10.3 tons/hr), #6 oil (300 gal/hr), "as fired" wood (12.2 tons/hr), & #2 oil (451.2 gal/hr)	035	262.3 MMBTU/hr	Cyclone dust collector ESP	None	BART eligible
Goodyear Tire & Rubber Co.[4]	OH	5,903	"A" Boiler, which is a coal-fired boiler	B101	301 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4
			"B" Boiler, which is a coal-fired boiler	B102	301 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4
			"C" Boiler, which is a coal-fired boiler	B103	174 MMBTU/hr	ESP	None	4.64 lbs of sulfur dioxide per MMBTU actual heat input for B101, B102, and B103 exiting through Stack 4

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Sunoco Inc. (R&M)[15, 16]	PA	3,645	Plt. 10-4 FCC Unit	101	4,792.000 bbl/hr fresh feed	None	SCR and a wet gas scrubber installed in 2010. At the latest, compliance is required by 2013.	SO_2 limit of 9.8 lbs/1000 lbs of coke burn-off in the catalyst regenerator determined daily on a 7-day rolling average basis
Valero Refining Co. – NJ[17, 18]	NJ	3,597	FCCU Regenerator with In-Line Heater	E21 or U1	102 MMBTU/hr	WGS	None	Per Consent Decree, SO_2 concentration emission limits at the point of emission to the atmosphere of no greater than 25 ppmvd, measured as a 365-day rolling average, and 50 ppmvd, measured as a 7-day rolling average, both at 0% O_2.
Stone Container Corp. (dba Smurfit-Stone Contain)[19]	VA	3,379	#8 Power Boiler that burns bituminous coal	2	1,056 MMBTU/hr	None	Wet gas scrubber (2007)	Consent Decree dated 11/2004 which states that SO_2 emission rate will not exceed 0.26 lb/MMBTU on a 30-day rolling average basis.

Table 5.1 Point Source Information Collected from the Top 17 Industrial Facilities Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
Great Northern Paper Inc. Mill West[20, 21]	ME	1,842	Power Boilers #4 (Riley-Stoker))	004 (WB4)	740 MMBTU/hr	None	None	Unit to be shut down so BART not an issue (only BART eligible source at this facility)
NRG Energy Center Dover LLC[1, 22, 23]	DE	1,836	Riley Stoker Boiler fired on pulverized bituminous coal (primary fuel) and natural gas (for startup/ignition).	C-1 (001)	243 MMBTU/hr	Four (4) DB Riley Low NO_X burners Cyclonic Combustion Venturi burner assemblies Low excess air ESP w/23,000 ft^2 collecting electrode area	None	Not BART eligible
Sappi-Somerset[20, 21]	ME	1,734	Power Boiler #1 (Babcock & Wilcox)	001 (PB#1)	848 MMBTU/hr (all fuels) & 250 MMBTU/hr (fossil fuels)	None	None	CEMS for SO_2 Facility to reduce SO_2 emissions by 50% by 2013 (BART deadline)

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[1] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Motiva Enterprises LLC – Delaware City and NRG Energy Center Dover LLC facilities received from Mr. John Sipple (302-739-9435, John.Sipple@state.de.us) via E-mail on March 13, 2007.

[2] New York State Department of Environmental Conservation, Division of Air Resources. Personal communications regarding Kodak Park Division facility between Mr. Mike Cronin, P.E. (518-402-8403, mpcronin@gw.dec.state.ny.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 1 and 9, 2007.

[3] New York State Department of Environmental Conservation, Division of Air Resources. Personal communications regarding Kodak Park Division facility from Mr. Mike Cronin, P.E. (518-402-8403, mpcronin@gw.dec.state.ny.us) via E-mail on February 12, 2007.

[4] Ohio Environmental Protection Agency, Division of Air Pollution Control. Personal communication regarding MW Custom Papers LLC – Chillicothe Mill and Goodyear Tire and Rubber Company facilities from Mr. William Spires (614-644-3618, bill.spires@epa.state.oh.us) via E-mails on February 20, 2007.

[5] Tennessee Department of Environment and Conservation, Division of Air Pollution Control. Personal communication regarding Eastman Chemical Company facility from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 1, 2007.

[6] MACTEC Federal Programs, Inc., "Revised Draft Final, Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Areas", March 8, 2007. Comments regarding Eastman Chemical Company facility received from Ms. Julie Aslinger (615-532-0587, Julie.Aslinger@state.tn.us) via E-mail on March 30, 2007.

[7] Maryland Department of the Environment. Personal communication regarding Westvaco Fine Papers facility between Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[8] Maryland Department of the Environment. Personal communication regarding Westvaco Fine Papers facility from Mr. Andy Heltibridle (410-537-4218, aheltibridle@mde.state.md.us) via E-mail on January 31, 2007.

[9] West Virginia Division of Air Quality. Personal communications regarding PPG, Industries, Inc. facility between Ms. Laura Crowder (304-926-0499 Ext. 1247, LCROWDER@wvdep.org) and Mr. Steve Pursley (304-926-0499 Ext. 1218) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on March 14, 2007.

[10] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Mead Westvaco Packaging Resource Group facility between Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 20, 2007.

[11] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communication regarding PH Glatfelter Company/Spring Grove facility between Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[12] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding PH Glatfelter Company/Spring Grove facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on January 31 and February 7, 2007.

[13] Illinois Environmental Protection Agency, Bureau of Air. Personal communication regarding Williams Ethanol Services Incorporated and Corn Products International Incorporated facilities between Mr. Rob Kaleel (217-524-4387, Rob.Kaleel@illinois.gov) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on February 2, 2007.

[14] Illinois Environmental Protection Agency, Bureau of Air. Personal communication regarding Williams Ethanol Services Incorporated and Corn Products International Incorporated facilities from Mr. Rob Kaleel (217-524-4387, Rob.Kaleel@illinois.gov) via E-mail on February 2, 2007.

[15] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Sunoco Inc. (R&M) facility between Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31, 2007.

[16] Pennsylvania Department of Environmental Protection, Bureau of Air Quality. Personal communications regarding Sunoco Inc. (R&M) facility from Ms. Nancy Herb (717-783-9269, nherb@state.pa.us) via E-mail on February 22, 2007.

[17] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communications regarding Valero Refining Company facility between Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on January 31 and February 2, 2007.

[18] New Jersey Department of Environmental Protection, Division of Air Quality. Personal communication regarding Valero Refining Company facility from Mr. Ray Papalski (609-633-7225, Ray.Papalski@dep.state.nj.us) via E-mail on February 21, 2007.

[19] Virginia Department of Environmental Quality, Division of Air Quality. Personal communication regarding Stone Container Corporation facility from Ms. Doris McLeod (504-698-4197, damcleod@deq.virginia.gov) via E-mail on February 9, 2007.

[20] Maine Department of Environmental Protection Agency, Bureau of Air Quality. Personal communications regarding Great Northern Paper Incorporated Mill West and Sappi - Somerset facilities between Ms. Lynn Ross (207-287-8106, Lynn.Ross@maine.gov) and Mr. Marc Cone (207-287-2437) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on February 2, 2007.

[21] Maine Department of Environmental Protection Agency, Bureau of Air Quality. Personal communication regarding Great Northern Paper Incorporated Mill West and Sappi - Somerset facilities between Ms. Lynn Ross (207-287-8106, Lynn.Ross@maine.gov) via E-mail on February 2, 2007.

[22] Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management. Personal communications regarding NRG Energy Center Dover LLC facility between Ms. Tammy Henry (302-323-4542, Tammy.Henry@state.de.us) and Ms. Lori Cress, MACTEC Federal Programs, Inc. on March 5, 2007.

[23] Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management. Personal communications regarding NRG Energy Center Dover LLC facility from Ms. Tammy Henry (302-323-4542, Tammy.Henry@state.de.us) via E-mail on March 5, 2007.

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CHAPTER 6

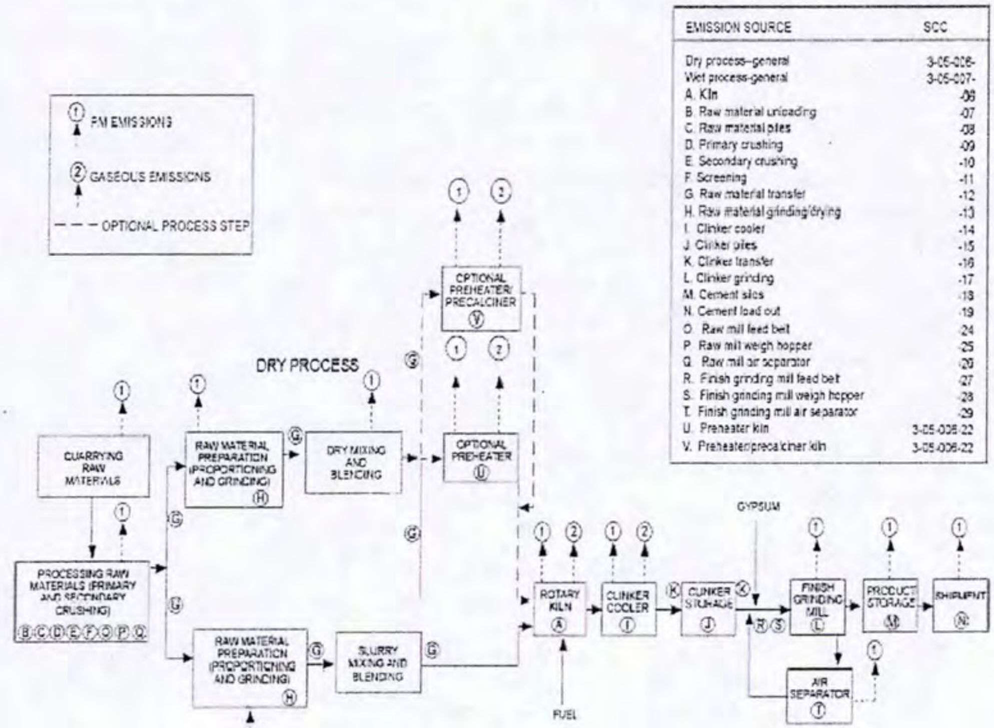
SOURCE CATEGORY ANALYSIS: KILNS

SOURCE CATEGORY DESCRIPTION

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 1,400°C (2,650°F). High combustion temperatures require large amounts of fuel and can result in significant emissions of SO_2 and NO_X. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

Figure 6.1 shows a process flow diagram of a Portland cement facility. The process flow diagram (taken from AP-42) shows both wet and dry Portland cement processes.

Figure 6.1 Portland Cement Process Flow Diagram



EMISSION SOURCE	SCC
Dry process–general	3-05-006-
Wet process-general	3-05-007-
A. Kiln	-06
B. Raw material unloading	-07
C. Raw material piles	-08
D. Primary crushing	-09
E. Secondary crushing	-10
F. Screening	-11
G. Raw material transfer	-12
H. Raw material grinding/drying	-13
I. Clinker cooler	-14
J. Clinker piles	-15
K. Clinker transfer	-16
L. Clinker grinding	-17
M. Cement silos	-18
N. Cement load out	-19
O. Raw mill feed belt	-24
P. Raw mill weigh hopper	-25
Q. Raw mill air separator	-26
R. Finish grinding mill feed belt	-27
S. Finish grinding mill weigh hopper	-28
T. Finish grinding mill air separator	-29
U. Preheater kiln	3-05-006-22
V. Preheater/precalciner kiln	3-05-006-22

EPA. January, 1995. AP42 Section 11.6 – "Portland Cement Manufacturing".

Figure 6.1 shows that the Portland cement process can generally be broken down into the following steps: raw materials handling, raw material preparation, dry mixing, optional preheating and/or precalcining, kiln treatment (pyroprocessing step), clinker handling and storage, and finishing operations (finishing, storage and shipment). The pyroprocessing step transforms the raw mix into clinkers, which are gray, glass-hard, spherically shaped nodules that range from 0.125 to 2.0 inches in diameter.

The pyroprocessing step is the predominant source of gaseous pollutant emissions. In general, there are five different processes used in the Portland cement industry to accomplish the pyroprocessing step: the wet process, the dry process (long dry process), the semidry process, the dry process with a preheater, and the dry process with a preheater/precalciner.

Each of the pyroprocessing types vary with respect to equipment design, method of operation, and fuel consumption. Generally, fuel consumption decreases in the order of the processes listed due to the heat required to evaporate water present in the raw material slurry (e.g., wet processes use the most fuel).

In the long dry process, all of the pyroprocessing activity occurs in the rotary kiln. Dry process pyroprocessing systems have been improved in thermal efficiency and productive capacity through the addition of one or more cyclone-type preheater vessels in the gas stream exiting the rotary kiln. This system is called the preheater process. The vessels are arranged vertically, in series, and are supported by a structure known as the preheater tower. Hot exhaust gases from the rotary kiln pass countercurrently through the downward-moving raw materials in the preheater vessels. Compared to the simple rotary kiln (long dry process), the heat transfer rate is significantly increased, the degree of heat utilization is greater, and the process time is markedly reduced by the intimate contact of the solid particles with the hot gases. The improved heat transfer allows the length of the rotary kiln to be reduced. An added benefit of the preheater operation is that hot gases from the preheater tower are used to help dry raw materials in the raw mill. Because the catch from the mechanical collectors, fabric filters, and/or electrostatic precipitators (ESP) that follow the raw mill is returned to the process, these devices can also be considered to be production machines as well as pollution control devices.

Additional thermal efficiencies and productivity gains have been achieved by diverting some of the fuel to a calciner vessel at the base of the preheater tower. This system is called the preheater/precalciner process.

Regardless of the type of pyroprocess used, the last component of the pyroprocessing system is the clinker cooler. The clinker cooler serves two main purposes. First, this portion of the process:

- recoups up to 30% of the heat input to the kiln system;
- locks in desirable product qualities by freezing mineralogy; and
- makes it possible to handle the cooled clinker with conventional conveying equipment.

The more common types of clinker coolers are reciprocating grate, planetary, and rotary. In these coolers, the clinker is cooled from about 1,100°C to 90°C (2000°F to 200°F) by ambient air that passes through the clinker and into the rotary kiln for use as combustion air. However, in the reciprocating grate cooler, lower clinker discharge temperatures are achieved by passing an additional quantity of air through the clinker. Because this additional air cannot be used in the kiln for efficient combustion, it is vented to the atmosphere, used for drying coal or raw materials, or used as a combustion air source for the precalciner.

The second portion of the clinker process, a series of blending and grinding operations, completes the transformation of clinker into finished cement. Up to 5% gypsum or natural anhydrite is added to the clinker during grinding to control the cement setting time, and other specialty chemicals are added as needed to impart specific product properties. This finish milling is accomplished almost exclusively in ball or tube mills. Typically, finishing is conducted in a closed-circuit system, with product sizing by air separation.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes to the product. The current fuel usage in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). In addition to conventional fuels, many Portland cement facilities are employing the use of petroleum derived coke (petcoke) blended with coal to fire kilns.

Lime kilns are similar to cement kilns. The kiln is the heart of the lime manufacturing plant, where various fossil fuels (such as coal, petroleum coke, natural gas, and fuel oil) are combusted to produce the heat needed for calcination. There are five different types of kilns used in lime manufacturing: rotary, vertical, double-shaft vertical, rotary hearth, and fluidized bed. The most popular is the rotary kiln, however the double-shaft vertical kiln is an emerging new kiln technology gaining in acceptance primarily due to its energy efficiency. Similar to cement plants, rotary kilns at lime manufacturing plants may also have preheaters to improve energy efficiency. Additionally, energy efficiency is improved by routing exhaust from the lime cooler to the kiln. SO_2 emissions from lime predominately originate from compounds in the limestone feed material and fuels and are formed from the combustion of fuels and the heating of feed material in the kiln.

All types of kilns at lime manufacturing plants use external equipment to cool the lime product, except vertical (including double-shaft) kilns, where the cooling zone is part of the kiln. Ambient air is most often used to cool the lime (although a few use water as the heat transfer medium), and typically all of the heated air stream exiting the cooler goes to the kiln to be used as combustion air for the kiln. The exception to this is the grate cooler, where more airflow is generated than is needed for kiln combustion, and consequently a portion (about 40%) of the grate cooler exhaust is vented to the atmosphere. EPA has estimated that there are about five to ten kilns in the United States that use grate coolers. The emissions from grate coolers include lime dust (PM) and trace metallic HAPs found in the lime dust, but not typically SO_2.

For cement and lime kilns, add-on control technology options identified for SO_2 include advanced flue gas desulfurization (AFGD), dry FGD, and wet FGD.

EVALUATION OF SO_2 EMISSION CONTROL OPTIONS

Sulfur dioxide may be generated both from the sulfur compounds in the raw materials and from sulfur in the fuel. The sulfur content of both raw materials and fuels varies from plant to plant and with geographic location. However, the alkaline nature of the cement provides for direct absorption of SO_2 into the product, thereby reducing the quantity of SO_2 emissions in the exhaust stream. Depending on the process and the source of the sulfur, SO_2 absorption ranges from about 70% to more than 95%.

In contrast to electric utility and industrial boilers, SO_2 emissions from rotary cement kilns are not strongly dependent on fuel sulfur content. Instead, SO_2 emissions are more closely related to the amount of sulfide (e.g. pyrite) in kiln feedstocks and to the molar ratio of total sulfur to total alkali input to the system. In cement kilns SO_2 emissions generally depend on:

- Inherent SO_2 removal efficiency of kiln system during processing,
- Form of sulfur (e.g. pyritic) and sulfur concentrations in raw material,
- Molecular ratio between sulfur and alkalis,
- Prevailing conditions (oxidizing or reducing) and their location within the kiln, and
- Temperature profile in the kiln system.

SO_2 emission reductions may also result from attempts to reduce other pollutants (primarily NO_X), typically due to changes in the flame characteristics of combustion. For example, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO_2. Similarly, including high pressure air injection at a mid-kiln firing site can limit oxygen in the kiln and suppress SO_2 formation (Hansen, 2002). Since these techniques are primarily used to reduce NO_X and because their efficiencies are typically more limited than other techniques they are not considered in additional detail here.

Other more specific SO_2 control technologies applicable to cement kilns are listed below. A summary of controls evaluated for this work is provided in Table 6.1. Details of each of the control technologies follow Table 6.1. Additional information on this source category and associated controls can be found in the 2005 NESCAUM document titled: *Assessment of Control Technology Options for BART-Eligible Sources.*

Table 6.1 SO_2 Control Technologies for Cement Kilns

Technology	Description	Applicability	Performance
Fuel Switching	Limiting the sulfur content of both raw materials and fuels can reduce releases of SO_2. Availability of these materials is highly site-specific.	All Kilns	Depends on availability of low-sulfur raw materials
Dry Flue Gas Desulfurization - Spray Dryer Absorption (FGD)	Addition of absorbents such as slaked lime (Ca(OH)2), quicklime (CaO) or activated fly ash with high CaO content to the exhaust gas of the kiln can absorb some of the SO_2.	All Kilns	60-80% reduction
Wet Flue Gas Desulfurization (FGD)	SO_2 is absorbed by a liquid/slurry sprayed in a spray tower or is bubbled through the liquid/slurry. Wet scrubbers also significantly reduce the HCl, residual dust, metal and NH_3 emissions.	All Kilns	90-99.9% reduction
Advanced Flue Gas Desulfurization (FGD)	DOE demonstrated a retrofit Passamaquoddy Technology Recovery Scrubber™ using cement kiln dust (CKD), an alkaline-rich (potassium) waste, to react with the acidic flue gas.	All Kilns	95-99.5% reduction

Table References:
1. *Assessment of Control Technology Options for BART-Eligible Sources*, NESCAUM, March 2005.
2. Miller, F.M. et. al. *Formation and Techniques of Control of Sulfur Dioxide and Other Sulfur Compounds in Portland Cement Kiln Systems*. Portland Cement Association R&D Serial No. 2460, 2001.

Fuel Switching

As with any fuel-fired SO_2 emission source, reduction of sulfur levels in the fuel itself typically results in lowered emissions. However, this technique is less effective in cement-making systems, where SO_2 emissions are not strongly dependent on fuel sulfur content. Depending upon the level of sulfur in a plant's limestone, and more specifically the pyrite content, compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit in SO_2 levels.

Flue Gas Desulfurization (FGD)

Both wet and dry flue gas desulfurization (FGD) systems have been used effectively to control SO_2 emissions from cement kilns. FGD systems at cement facilities typically are, 1) dry flue gas desulfurization (spray dryer absorption) 2) wet flue gas desulfurization, and 3) advanced flue gas desulfurization (AFGD). A brief description of each of these technologies is provided below.

Dry Flue Gas Desulfurization (Spray Dryer Absorption)

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming a mixture of calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or ESP. When used to specifically control SO_2, the term dry flue-gas desulfurization (dry FGD) may also be used. As with other types of dry scrubbing systems (such as lime/limestone injection) exhaust gases that exit at or near the adiabatic saturation temperatures can create problems with this control technology by causing the baghouse filter cake to become saturated with moisture and plug both the filters and the dust removal system. In addition, the lime slurry would not dry properly and would plug up the dust collection system. However there is some argument in the control community that indicates that some of the SO_2 removal actually occurs on the filter cake. Therefore, dry FGD (spray dryer absorption) may not be technically feasible if exit gas temperatures are not substantially above the adiabatic saturation temperatures. For Portland cement facilities, these temperatures are likely to be above the adiabatic saturation temperatures.

Most of the spray dryer type SO_2 control technologies in the cement industry are applied to preheater or preheater/precalciner kilns. Exhaust gases from long dry kilns are cooled by either spray water introduced into the feed end of the kiln or by dilution air-cooling after the gases leave the kiln. Adding a conditioning tower to replace wet suppression or dilution air enables the alkaline slurry system to be used to reduce SO_2 emissions (the equivalent of a spray dryer). The use of an alkaline slurry spray dryer type scrubber should be applied to long wet kilns with care because the addition of the lime slurry may drop the exhaust gases temperature below the acid adiabatic saturation temperatures, creating significant plugging and corrosion problems in the downstream particulate control device, duct work, and induced draft fan.

Wet Flue Gas Desulfurization (FGD)

Wet scrubbing processes used to control SO_2 and particulate emissions are generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO_2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. Our screening evaluation assumes that lime is the scrubbing agent.

Caustic scrubbing produces a liquid waste, and minimal equipment is needed. When lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery and is typically stabilized with fly ash for land filling. Calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur. The normal SO_2 control efficiency range for SO_2 scrubbers is 80-90% for low efficiency scrubbers and 90-99.9% for high efficiency scrubbers.

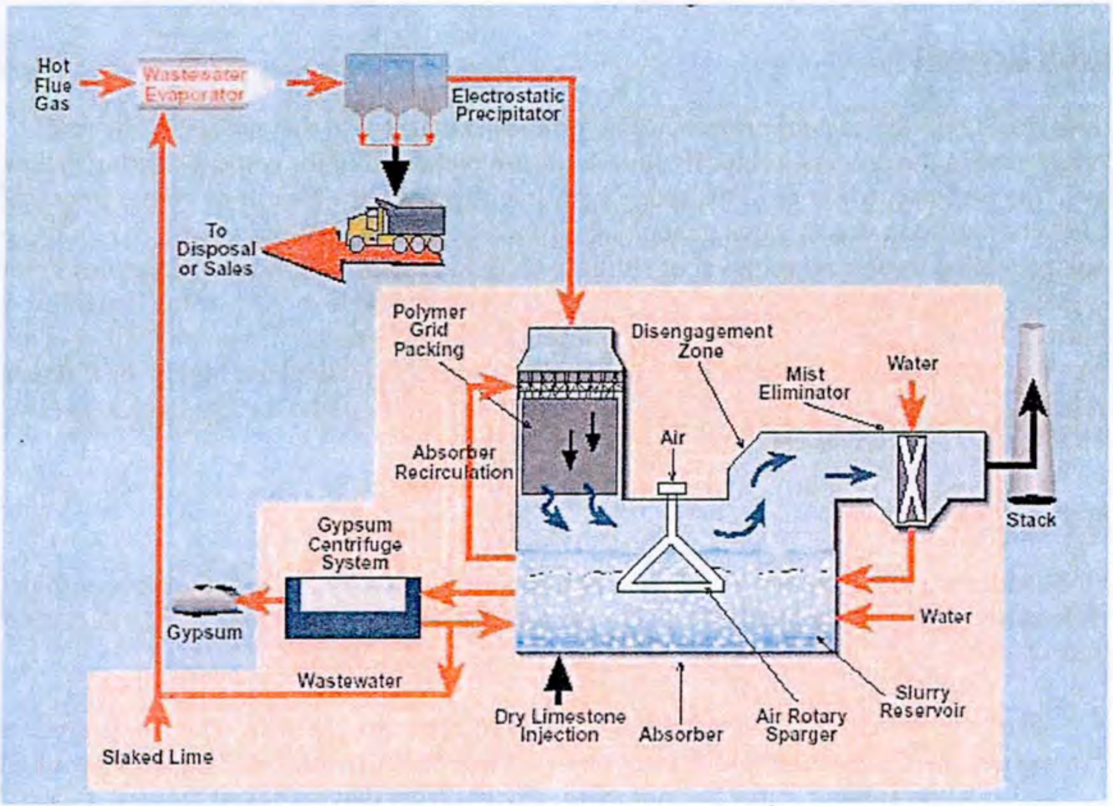
While wet scrubbers have been used successfully in the utility industry, they require more care when used for a Portland cement facility. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control (applied to the exhaust gas from a cement kiln) can be avoided if these systems are installed downstream of a high efficiency particulate control device (e.g., fabric filter). Failure of the particulate control device can pose difficult problems for a downstream wet scrubber.

Advanced Flue Gas Desulfurization (FGD)

The AFGD process accomplishes SO_2 removal in a single absorber which performs three functions: prequenching the flue gas, absorbing SO_2, and oxidizing the resulting calcium sulfite to wallboard-grade gypsum. Figure 6.2 shows the process flow for an AFGD system.

Incoming flue gas is cooled and humidified with process wet suppression before passing to the absorber. In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator.

Figure 6.2 Advanced Flue Gas Desulfurization Process Flow



As the flue gas contacts the slurry, the sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$CaCO_3 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + CO_2$

$CaSO_3 \cdot 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \cdot 2\ H_2O$

After contacting the flue gas, slurry falls into the slurry reservoir where any unreacted acids are neutralized by limestone injected in dry powder form into the reservoir. The primary reaction product, calcium sulfite, is oxidized to gypsum by the air rotary spargers, which both mix the slurry in the reservoir and inject air into it. Fixed air spargers assist in completing the oxidation. Slurry from the reservoir is circulated to the absorber grid.

A slurry stream is drawn from the tank, dewatered, and washed to remove chlorides and produce wallboard quality gypsum. The resultant gypsum cake contains less than 10% water and 20 ppm chlorides. The clarified liquid is returned to the reservoir, with a slipstream being withdrawn and sent to the wastewater evaporation system for injection into the hot flue gas ahead of the electrostatic precipitator. Water evaporates and dissolved solids are collected along with the flyash for disposal or sale.

The production of gypsum may actually be beneficial for Portland cement as gypsum is added to Portland cement in the final grinding process to regulate the setting time of the concrete. However, to date there are no known installations of AFGD at Portland cement facilities.

Inherent Removal

Removal of SO_2 in the cement manufacturing process is inherent to that process. The raw materials used in the process, primarily limestone, are preheated in the cement-making process either in the preheater tower or in the rotary kiln. In either case, the limestone comes in contact with hot combustion exhaust gases generating a free lime, which then reacts with SO_2 in the gas stream, providing in-process removal of sulfur in the kiln system. Removal efficiencies in rotary kiln systems range between 38% and 99% of sulfur input, and 50% to 70% of the remaining SO_2 is removed from exhaust gases when passing through an in-line raw mill system (Miller et al., 2001). The overall effectiveness and costs associated with this method are highly variable and are related primarily to the type of kiln operation and the ability of the facility to change raw material feeds. These costs can be difficult to quantify.

Process Alterations

The following methods to remove and prevent formation of SO_2 by modifying or controlling conditions in the system are available due to the nature of the Portland cement manufacturing process:

- Change in the oxygen concentration in the flame/exhaust gas area. The concentrations of oxygen and (more importantly) carbon monoxide strongly influence the stability of alkali and calcium sulfates in the burning zone. By ensuring that sufficient oxygen is present to stabilize these compounds, SO_2 emissions can be controlled. Control of burning-zone O_2 and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary cement kilns. The downside of this technique is the more favorable conditions created for generation of NO_X in the rotary kiln.

- Burning-zone flame shape can be modified to ensure that reducing conditions in the flame are minimized. Flame impingement in the hot zone has a major effect on SO_2 emissions from the kiln, even if total oxygen is sufficient to fully combust all fuel. Avoiding flame impingement in the burning zone minimizes SO_2 formation. Avoiding flame impingement on the clinker, a technique applicable to all rotary kilns producing cement clinker, requires proper solid fuel preparation and proper flame shaping and control.
- Changes in raw materials to alter the alkali/sulfur molar ratio can also be used to control SO_2 emissions. SO_2 concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur. When there are sufficient alkalis in excess of sulfur, SO_2 emissions are typically low, due to more sulfur being retained as alkali sulfates in the clinker. Cement plants may also change their raw materials to reduce SO_2 emissions. Typically this is accomplished by substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds, leading to reduced SO_2 emissions. Replacement of raw materials, however, is often constrained by economic considerations, while alkali input increase may also be limited by cement product quality specifications on total alkali in cement.
- Alterations to system can influence SO_2 emissions. It has been found that an improved distribution of kiln feed may equalize temperatures in bottom stage cyclones and reduce SO_2 emission by as much as 20% (Miller, 2001).

As with inherent removal, the overall effectiveness and costs associated with this method are highly variable and are related primarily to the type of kiln operation and the ability of the facility to change raw material feeds. These costs can be difficult to quantify.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR KILNS

Cost of Compliance

To compare the various control options, information has been compiled on the cost-effectiveness of retrofitting controls. In general, cost-effectiveness increases with the amount of cement produced by the facility.

In a study performed for LADCO for a BART analysis, MACTEC developed control costs for SO_2 for a "model" cement plant for SO_2. For the wet scrubber, the control cost estimates were prepared using lime as the base in the scrubbing liquor. Caustic (NaOH) and limestone are potential alternatives for a scrubber and could change the costs slightly. While lime and limestone require additional equipment for slurry preparation and for solids separation from the sludge generated in the scrubber, lime scrubbers are the most commonly used since lime is plentiful and relatively cheap. Materials of construction must also be made suitable for caustic, lime, or limestone if existing equipment is modified for wet scrubbing of SO_2.

AFGD systems require additional capital costs for the spargers and blowers necessary to oxidize the waste product to gypsum and for equipment to dewater the product (e.g., centrifuge). However if the commercial grade gypsum can be sold or used by the cement facility, some of these costs can be offset.

Dry FGD costs were calculated based on the low and high control efficiencies typical for these systems. For dry scrubbers, the flue gas must be cooled to a temperature 10 to 20 degrees above adiabatic saturation. This is typically accomplished using a heat recovery boiler, an evaporative cooler or a heat exchanger. In addition, if the facility does not have one, a particulate removal device is required for removal of the dry materials used to absorb SO_2.

For all scrubbers, costs for an additional or upgraded induced air draft fan to make up for pressure drops within the system may be required. In addition, for wet systems, flue gas reheating may be required, thus a reheater may be necessary.

Tables 6.2 – 6.4 present estimated SO_2 control costs for AFGD, Wet FGD, and Dry FGD applied to dry kilns and preheater kilns. The range of costs for these systems vary depending on the size of the kiln and control efficiency, so costs are presented for three size ranges of kilns. Although the capital and annual operating costs of these three types of control vary widely depending on kiln size and control efficiency, the ultimate cost in terms of \$/ton of SO_2 reduction are estimated to be from \$2,000 - \$7,000 for dry kilns and \$9,000 to \$73,000 for preheater kilns.

Table 6.2 SO_2 Control Costs for AFGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			Preheater Kiln		
Unit Relative Size	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)
Small	\$7.03 – \$22.9	\$3 - \$6	\$2,000 - \$4,000	\$4.5 - \$14.5	\$1.2 – \$11.8	\$13,600- \$38,000
Medium	\$14.1 - \$45.9	\$6.1 - \$11.9		\$8.9 - \$29.0		
Large	\$28.1 - \$91.6	\$12.1 – \$23.7		\$17.8 - \$58.0		

Table 6.3 SO_2 Control Costs for Wet FGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			Preheater Kiln		
Unit Relative Size	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)
Small	\$2.43 – \$36.5	\$3 - \$9	\$2,000 - \$6,200	\$1.5 - \$23.1	\$0.9 – \$18.9	\$9,700- \$64,600
Medium	\$4.9 - \$73.0	\$6.0 - \$18.4		\$3.1 - \$46.3		
Large	\$9.5 - \$142.5	\$11.9 – \$36.8		\$6.2 - \$92.5		

Table 6.4 SO_2 Control Costs for Dry FGD Applied to Dry Kilns and Preheater Kilns (2006 dollars)

	Dry Kiln			**Preheater Kiln**		
Unit Relative Size	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)	Capital Costs (10^6 \$)	Annual Operating Costs (10^6 \$)	SO_2 Cost Effectiveness (\$/ton SO_2 reduction)
Small	\$1.45 – \$37.0	\$3 - \$9	\$1,900 - \$7,000	\$0.9 - \$26.3	\$0.9 – \$21.0	\$10,000-\$72,800
Medium	\$2.9 - \$84.9	\$5.5 - \$20.0		\$1.8 - \$52.6		
Large	\$5.6 - \$165.5	\$10.7 – \$38.9		\$3.6 - \$105.2		

The LADCO region had no wet kilns so cost estimates were not available for those type kilns. For the purposes of this study, wet kiln cost effectiveness is assumed to be similar to that for long dry kilns.

Additional details concerning the calculation of cost effectiveness of controls for kilns is located in a document developed by MACTEC for LADCO titled: *Cement Best Available Retrofit Technology (BART) Engineering Analysis*. This document can be downloaded from the web at the following location:
http://www.ladco.org/reports/rpo/Regional%20Air%20Quality/BART/Cement_BART_Engineering%20Analysis%20%2B%20Appendix%20A1.pdf.

Time Necessary for Compliance

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the NO_X SIP Call for Phase I sources, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the NO_X SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

For the purposes of this review, we have assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a three year period for the installation of post combustion controls.

Energy and Non-Air Impacts

Fuel switching and cleaning and process changes do not significantly impact efficiency of the cement operation, but may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

Environmental Impacts

The primary environmental impact of AFGD is the generation of byproduct gypsum. While gypsum is generated as a byproduct, the intent of the AFGD system is to produce gypsum that is commercial grade that can be sold. In the case of cement kilns, production of gypsum would result in some cost offsets since gypsum is a component of Portland cement. Thus the gypsum produced could be used to offset gypsum purchases.

The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from wet scrubbers will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge is water-laden, and it must be stabilized for land filling. If lime or limestone scrubbing is used to produce calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required. Scrubber exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

Disposal of removed material from dry FGD systems is also required and will result in landfill impacts.

Energy Impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In addition for some technologies, a flue gas reheater may be required resulting in slightly increased fuel usage.

Remaining Useful Life of the Source

MACTEC could find little information on the typical lifetime of a cement plant. In a Security and Exchange filing (http://www.secbd.org/prosmcldopr.html) for a facility in India, typical lifetimes of various components of the plant range between 20-50 years. In an evaluation of waste management of cement kiln dust (CKD), remaining useful lifetimes of waste management units were around 20 years (http://www.epa.gov/epaoswer/other/ckd/rtc/chap-4.pdf). Thus we found nothing to suggest that the amortization of capital costs or calculation of annual operating costs would be affected by the remaining useful life.

For the purposes of this analysis, we assumed that the remaining useful life of each emission unit was a minimum of at least 10 years and that it was likely that some units would continue to operate for at least 20-30 more years with proper maintenance and upkeep.

REFERENCES

Assessment of Control Technology Options for BART-Eligible Sources, NESCAUM, March 2005.

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CHAPTER 7

ANALYSIS OF SELECTED KILNS

SOURCE CATEGORY DESCRIPTION

Emission control regulations for cement kilns have historically focused on particulate emissions. Over the past several years, regulations for the control of NO_X and hazardous air pollutant (HAP) emissions have also been adopted. SO_2 emission controls are largely non-existent. Some States have mandated emission limits as part of the Title V requirements but no national regulatory program for SO_2 controls for cement kilns exists. The only exceptions to this is for sources subject to New Source Review under Title I of the Clean Air Act and for sources subject to the Best Available Retrofit Technology (BART) requirements of the regional haze regulations.

Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. The control strategies that constitute BACT and LAER evolve over time and are reviewed on a case-by-case basis in State permitting proceedings.

INFORMATION OBTAINED FROM STATE AGENCIES

MACTEC contacted State agencies to obtain information on kilns from those facilities in the list of the top 20 individual non-EGU sources. We requested permit information, information about SO_2 controls recently implemented or planned at the facility and any available information on BART, consent decrees, or other regulations that will impact control devices at the facilities. The information we obtained is included in Table 7.1.

Table 7.1 Point Source Information Collected from the Top 3 Kilns Responsible for Visibility Impairment in MANE-VU Class I Areas

Facility Name	State	2002 SO_2 Total (tons)	Primary Emissions Point Description	Point ID (Permit ID No.)	Design Capacity	Existing Control(s)	Proposed/ Planned Control(s)	Additional Information
LaFarge Building Materials Inc.[1]	NY	14,800	Two rotary, wet process kilns (Kiln 1 & 2) and two clinker coolers (Clinker Cooler 1 & 2). There are buildings at either end of the kilns; the discharge end building where the clinker coolers are located, and the feed end building.	041000	Unknown	Fabric filter dust collector on clinker coolers (PM) ESP (PM)	None	
St. Lawrence Cement Corp. – Catskill Quarry[2, 3]	NY	3,562	Cement kiln permitted to burn coal, oil, tires, waste oil, natural gas, non-hazardous fuels, and coke. This is a wet kiln built in 1964.	U00K18	Unknown	ESP	Low-sulfur fuel	Consent Decree dated 1/9/91 limits burning solid fuel with a max sulfur content of 3.8 lbs/MMBTU/hr. BART analysis has not been completed.
Lafarge Midwest, Inc., Alpena Plant[4]	MI	16,576	Five rotary dry kilns, clinker coolers and associated materials handling operations. Kilns fire with coal, coke or waste derived fuel	EU-Kiln19 EU-Kiln20 EU-Kiln21 EU-Kiln22 EU-Kiln23	Unknown	Baghouses on kiln dust return systems	Unknown as of date of report - these units are subject to BART	SO_2 Emission limits on all five kilns: EUKiln19 = 2,088 tons EUKiln20 = 2,065 tons EUKiln21 = 2,056 tons EUKiln22 = 9,685 tons EUKiln23 = 9,728 tons

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[1] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding LaFarge Building Materials Incorporated facility between Mr. Rick Leone (518-402-8403) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 2, 2007.

[2] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding St. Lawrence Cement Corporation – Catskill Quarry facility between Mr. Rick Leone (518-402-8403) and Ms. Lori Cress, MACTEC Federal Programs, Inc., on February 9, 2007.

[3] New York State Department of Environmental Conservation, Division of Air Resources. Personal communication regarding St. Lawrence Cement Corporation – Catskill Quarry facility from Mr. Rick Leone (518-402-8403) via E-mail on February 9, 2007.

[4] Michigan Department of Environmental Quality, Air Quality Division. Personal communication regarding LaFarge Midwest, Incorporated Alpena Plant from Ms. Teresa Walker (517-335-2247, walkertr@michigan.gov) via E-mail on February 7, 2007.

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CHAPTER 8

HEATING OIL

BACKGROUND

Number 2 distillate fuel oil, heating oil, and diesel fuel oil are essentially the same refinery-produced liquid. In the Northeast United States, home heating accounts for 54% of distillate fuel oil demand. In comparison, highway diesel accounts for 38% (NESCAUM, 2005). Annually, home heating oil use generates an estimated 100,000 tons of sulfur dioxide (SO_2) emissions in the Northeast (NESCAUM, 2005). Climate and seasonality play important roles in the use of heating oil, and therefore the emissions from combustion of heating oil. While it is important to consider the emissions from heating oil in the Northeast United States, emissions from heating oil combustion in other areas of the United States such as the VISTAS States are not significant in comparison to other emission sources.

SO_2 emissions are proportional to fuel oil sulfur content. It is not feasible to control SO_2 emissions from homes using control devices; therefore, the most efficient method for controlling SO_2 emissions from home heating is by lowering the amount of sulfur in the fuel. Currently, the sulfur limits in heating oil vary between 2,000 to 20,000 ppm. Table 8.1 provides information on the range of sulfur in heating oils throughout the Northeast.

Table 8.1 State Sulfur Limits for Heating Oil

State	Sulfur Limit in Percent	Sulfur Limit in parts per million (ppm)
Connecticut	0.3	3,000
Maine	0.3 to 0.5	3,000 to 5,000
Massachusetts	0.3	3,000
New Hampshire	0.4	4,000
New Jersey	0.2 to 0.3	2,000 to 3,000
New York Upstate	1.0 to 1.5	10,000 to 15,000
New York Downstate	0.2 to 0.37	2,000 to 3,700
Rhode Island	0.5	5,000
Vermont	2.0	20,000

Source: NESCAUM, 2005

Beginning in 2006, the permissible level of sulfur in highway diesel fuel (ultra low sulfur diesel, or ULSD) was 15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur (Low Sulfur Diesel, or LSD). Consequently, refineries have already performed the capital investments required for the production of LSD and ULSD fuel oil. The Northeast States are considering adopting consistent low sulfur heating oil requirements, and a memorandum titled *DRAFT Memorandum of Understanding for Regional Fuel Sulfur Content Standards for*

Distillate Number 2 Heating Oil, the Northeast States proposed to reduce the sulfur content to 500 ppm. A reduction of sulfur in heating oils from the current levels to 500 ppm would reduce SO_2 emissions by approximately 75% per year on a nationwide basis (Batey and McDonald, 2005). There has also been some discussion regarding the reduction of heating oil sulfur content to 15 ppm.

This memorandum presents the four factor analysis that was applied to the heating oil sulfur reduction proposal. The four factors are: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the sources. This document primarily focuses on reducing the sulfur content of heating oil to 500 ppm. Information on reducing the sulfur content of heating oil to 15 ppm is presented wherever data were available.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EMISSIONS FROM HEATING OIL COMBUSTION

Cost of Compliance

Refinery Retrofit Costs

Refineries were required to make significant capital investments to meet the LSD and ULSD highway fuel sulfur requirement. To achieve the LSD and ULSD sulfur goals, refineries were required to implement diesel desulfurization technologies. Estimates for the capital costs were developed in 2001 by the Energy Information Administration (EIA) and are based on calendar year 1999. Table 8.2 presents the capital costs for desulfurization technologies developed by the EIA, which were converted from a calendar year 1999 dollar basis to 2006 dollars. The EIA developed estimates for new and revamped desulfurization technologies at existing refineries.

Table 8.2 Ultra Low Sulfur Diesel (ULSD) Desulfurization Technology Costs for Individual Refineries[a,b]

Desulfurization Unit Type	Throughput (Barrels per Day)	Capital Costs (2006 Dollars per Daily Barrel Produced)	Total Capital Cost per Unit (Million 2006 Dollars)
New	50,000	1,204	60.3
New	10,000	2,187	21.9
Revamp	50,000	716	35.8
Revamp	10,000	1,464	14.6

[a] Based on cost estimates for hydrotreaters to produce ULSD.
[b] Source for this information is the Energy Information Administration
Note – A conversion factor of 1.2101 was used to convert the dollar values from 1999 to 2006 www.inflationdata.com

In its highway diesel fuel rulemaking, EPA also developed cost estimates for the deployment and implementation of desulfurization technologies at refineries. EPA estimated that it would cost existing refineries an estimated $56 million (2006 dollars) per refinery to install desulfurization technologies, and that this effort would be spread out over a 2-year time period. EPA based its conclusions on the assumption that refineries would revamp their hydrotreating technologies. It further estimated that 80% of the hydrotreaters at the refineries would be revamped. The EPA also estimated that the cost of a new hydrotreater would be $91 million (2006 dollars), and that roughly 25 refineries nationwide would have to make this investment. No estimates were made for the costs associated with new refineries as none are currently being constructed in the United States. The EPA analysis spread the investment cost over a 2-year period. Consequently, it was estimated that the US refinery-wide investment for calendar year 2004 was $2.45 billion and $2.83 billion for calendar year 2005 (EIA 2001) (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383. www.inflationdata.com).

In the August 9, 2006 edition of *This Week in Petroleum*, EIA reported that total ULSD production progress has been good and that ULSD is currently being produced in all Petroleum Administration for Defense Districts (PADDs). Stocks of ULSD in the United States in January 2007 were approximately equal to distillate oil containing greater than 500 ppm sulfur. However on the East Coast, stocks of ULSD were approximately one-third the size of distillate oil stocks containing more than 500 ppm sulfur (EIA). Another independent source, The Marathon Petroleum Company, LLC, found that 90% of refineries in the continental United States that were included in a survey had designed units capable of producing ULSD. Also, Marathon determined that the planned US capacity for ULSD would be in excess of 2.5 million barrels per day in 2006 (Marathon Petroleum Corporation 2007).

Heating Oil Cost Increases

It is assumed that the costs for retrofitting refineries will be passed on to consumers. In its December 2005 study, NESCAUM estimated that the average price increment for the lower sulfur product (500 ppm) would be $0.16 per gallon. In December 2005, this represented a 1% increase of the average oil price.

To update these costs we compared the costs of low-sulfur diesel fuel (15 – 500 ppm) with regular diesel fuel (2,000 ppm) for 2006. These data were gathered from DOE EIA Web site on March 8, 2007. We used the difference in diesel fuel prices because the cost for low sulfur heating oil is currently not reported and because diesel fuel and number 2 distillate are essentially the same product. It is therefore reasonable to assume that the cost differential between low sulfur and regular diesel fuel should reflect the potential cost differential between low sulfur and regular heating oil. All cost comparisons are before taxes. EIA only reports a low-sulfur diesel fuel category which includes both low sulfur (500 ppm) and ultra low sulfur diesel (15 ppm). For the first two months on 2007, EIA reports that stocks of 15 ppm sulfur oil were roughly twice that of 500 ppm sulfur oil. We averaged monthly costs to compute annual average costs for PADD 1A (CT, ME, MA, NH, RI, VT) and PADD 1B (DE, DC, MD, NJ, NY, PA) for low sulfur and regular diesel fuel from January to December 2006. For PADD 1A, the cost of low sulfur diesel fuel ranged from $1.954 to $2.433 per gallon and the cost of regular diesel fuel ranged from $1.963 to $2.429 per gallon. The monthly difference between low sulfur and regular diesel fuel ranged from -1.1 cents per gallon to 0.5 cents per gallon with an annual average of -0.8 cents per gallon. That is, low-sulfur diesel fuel was on average less expensive that regular diesel fuel in PADD 1A in 2006. Similarly in PADD 1B, the cost of low sulfur diesel fuel ranged from $1.894 to $2.358 per gallon and the cost of regular diesel fuel ranged from $1.894 to $2.321 per gallon. The monthly difference between low sulfur and regular diesel fuel ranged from -1.3 cents per gallon to 4.7 cents per gallon with an annual average of 1.6 cents per gallon. In both regions fuel costs were highest in the summer and the difference in cost between low sulfur and regular diesel fuel was also highest in summer. To calculate an average cost differential, we weighed the PADD 1A and PADD 1B cost differentials by residential fuel use in each PADD for 2005 (the latest date data are available from EIA). In 2005, PADD 1A States used 1.9 million gallons and PADD 1B States used 2.5 million gallons. Therefore, on average low sulfur distillate oil would be expected cost 0.8 cents per gallon more than regular heating oil in MANE-VU States. This average price differential translates in to $734/ton of sulfur removed if it assumed that the low sulfur diesel has a concentration of 500 ppm sulfur or $554/ton of sulfur removed for ultra low 15 ppm sulfur diesel.

STAPPA-ALAPCO (2006) estimates that the annual fuel oil consumption per household is 865 gallons per year. Using the price differential data presented above, the average household would spend about $7 per year additional on home heating costs by using low or ultra low sulfur fuel.

The use of LSD/ULSD will also result in cost savings to owners/operators of residential furnaces and boilers due to reduced maintenance costs. When the existing heating oil sulfur content is 2,000 ppm and 500 ppm sulfur is substituted, the service interval can be extended by a factor of three or more (e.g., cleaning at three year intervals rather than annually). Vacuums are used to remove deposition caused by SO_2 from furnaces and boilers.

The potential vacuum cleaning costs savings for the United States, for a starting fuel sulfur content of 2,000 ppm ranges from approximately $200 million a year to $390 million a year for service costs of $50 to $100 per hour. Therefore, if all oil heated homes switched to 500 ppm sulfur heating oil, more than $200 million a year could be saved, which would significantly lower the overall operating costs of fuel oil marketers. Given the dominant share of the U.S. heating oil market represented by the Northeast States, a large percentage of the projected national benefits would accrue in the region (NESCAUM 2005). In a brochure distributed by EIA titled *Residential Heating Oil Prices: What Consumers Should Know,* EIA reports that 6.3 million of the 8.1 million households using heating oil in the United States (78%) are in the Northeast Region. This region includes the New England and Central Atlantic States.

Heating Oil Supply

EPA addressed the issue of using ULSD for heating oil purposes in its regulatory impact analysis for Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (2000). EPA found that refiners in the Mid-Atlantic and Northeast (PADD 1) could produce more of this fuel and reduce the need for imports.

EIA reports that in 2004, 5,975,966,000 gallons of heating oil were sold in the United States. This decreased to 5,548,827,000 gallons in 2005. The EIA publishes weekly updates on the availability of heating oil. Information was retrieved for January 2007 and is summarized in Table 8.3 below.

Table 8.3 Average January 2007 Distillate Stocks (Million Barrels)[a]

Location	15 ppm and Under Stocks	15 ppm -- 500 ppm Stocks	>500 ppm Stocks	Total Distillate Stocks
US (Total)	57.2	25.0	59.7	141.8
East Coast	14.7	21.9	44.5	66.5
Average Days of Supply of Distillate Fuel Oil[b]	34.4	34.4	34.4	34.4

[a] Source for this information is the Energy Information Administration.
[b] The sulfur content of distillate stocks is not distinguished by the EIA for this data point.

The EIA also makes available information regarding the production and imports of heating oil. This information is summarized in Table 8.4, and includes specific data for the East Coast.

The information presented in Table 8.4 indicates that on a nationwide basis, more ULSD is produced than both LSD and high sulfur fuel. This is due to the predominant use of ULSD in highway diesel vehicles. This information also supports the conclusion that the United States has the infrastructure to produce adequate stocks of LSD and ULSD.

Table 8.4 Distillate Production and Imports (Million Barrels per Day)[a,b]

Location	15 ppm and Under Production	15 ppm - 500 ppm Production	>500 ppm Production	Total Distillate Production
US	2.659	0.624	0.970	4.253
East Coast	0.248	0.024	0.277	0.549
Imports	0.204	0.018	0.115	0.392

[a] Source for this information is the Energy Information Administration.
[b] Based on the four week average ending January 12, 2007.

Currently, the 15 ppm fuel is sold for highway use diesel, whereas the >500 ppm stocks are sold for heating oil. The 15-500 ppm fuel can still be used until 2010 under the hardship provisions of the heavy duty highway diesel program (EPA 2004). Under these provisions of the heavy duty highway diesel program, if there is a shortage of 15 ppm fuel, the 15 -500 ppm fuel could be used to relieve the shortage. With this flexibility, the likelihood of a fuel shortage in the short term, due to usage of ULSD for heating oil is reduced.

Time Necessary for Compliance

Refiners in the United States are already producing low sulfur highway diesel fuel. This same fuel can be marketed as heating oil since it is the same refinery product as highway diesel except with dye added to the fuel to differentiate it for tax purposes. Some time may be required to allow petroleum marketers to adjust to distributing ULSD to heating oil customers, however, the distribution network for motor fuels and heating oil are already in place.

NESCAUM (2005) estimated that during peak periods of demand, up to 20% of the required heating oil is imported. This analysis does not address whether offshore refineries should be able to produce 15 ppm sulfur for export to the Northeast United States. In case of a shortage of 15 ppm fuel during the transition period from LSD to ULSD, the heavy duty highway diesel program allows the use of 15-500 ppm sulfur fuel.

Existing residential furnaces and boilers do not need to be retrofitted or modified to combust 15 ppm sulfur. The capacity for producing LSD and ULSD already exists among US refiners. Consequently, the time necessary for compliance does not hinge on the heating oil furnace/boiler.

Energy and Non-Air Impacts

Reducing the sulfur contents of heating oil has a variety of beneficial consequences for residential furnaces and boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by the New York State Energy Research and Development Authority, (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (Batey and McDonald 2005). Batey and McDonald (2005) estimated that the potential cost savings from decreased vacuum cleanings ranges from $200 million per year to $390 million per year. The decreased deposits would also enable a more efficient transfer of heat, thereby reducing the fuel usage. Further reducing the heating oil sulfur from 500 to 15 ppm would increase the cost savings from decreased maintenance needs due to heat exchanger fouling.

The decreased sulfur levels would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing furnaces and boilers. These boilers recoup energy that is normally lost to the heating of water vapor in the exhaust gases. Historically, the use of high sulfur fuels prevented this due to the corrosion of the furnace/boiler due to the creation of sulfuric acid in the exhaust gases. The increased efficiency results in a decrease in the amount of heating oil a heating unit uses, therefore, this would make a switch to lower sulfur heating oils more attractive and cost effective.

Remaining Useful Life of the Source

Residential furnaces and boilers have finite life times, but they do not need to be replaced to burn low or ultra low sulfur fuel. The Energy Research Center estimates that the average life expectancy of a residential heating oil furnace is approximately 18 years, and that the average life expectancy of a residential heating oil boiler is 20-25 years (Personal communication with Mr. John Batey, Energy Research Center on February 6, 2007).

Finally, the number of homes that are being heated with heating oil is declining by approximately 100,000/year (RedOrbit 2007). No geographical distribution was available for this estimate, but since heating oil is predominantly used in the Northeast, most of the changes will be occurring there. Consequently, emissions from heating oil combustion will become less significant of a source of SO_2 emissions in the future.

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CHAPTER 9

RESIDENTIAL WOOD COMBUSTION

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate. However, in the MANE-VU Class I areas, biomass combustion also has been identified as a contributor to visibility impairment. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

In the document, *Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region*, OMNI Environmental Services, Inc. (OMNI) conducted a control analysis and documentation of residential wood combustion (RWC) in the 11 States and the District of Columbia that make up the MANE-VU region. Information for the OMNI analysis was obtained from: (1) The MANE-VU Residential Wood Combustion Emission Inventory published by MARAMA (July 2004 report), (2) Residential Energy Consumption Surveys published by the EIA, (3) the National Emission Inventory published by the EPA, (4) Simmons Marketing Research reports, and (5) American Housing Surveys for the United States published by the U.S. Department of Commerce and the U.S. Department of Housing and Urban Development. In addition, the results of three RWC surveys at the State-level have been published in the last decade for the Mid-Atlantic and New England area, which allow for comparison of data extrapolated from the national- and regional-scale surveys to the State level for three States. These were the: (1) 1995 Delaware Fuelwood Survey, (2) Residential Fuelwood Use in Maine, Results of 1998/1999 Fuelwood Survey, and (3) Vermont Residential Fuel Wood Assessment for 1997-1998.

To facilitate understanding of the cost effectiveness analyses done by OMNI, descriptions of the various appliances used, as well as a brief discussion of efficiency, are provided from the OMNI report.

Cordwood-Fired Stoves and Fireplace Inserts

Uncertified, certified catalytic, and certified non-catalytic cordwood stoves and fireplace inserts together are considered cordwood heaters. They are designed to burn bulk cordwood and are room space heaters, i.e., they primarily rely on radiant and convection heat transfer, in contrast to centralized heating systems such as warm-air furnaces or boilers which utilize heat distribution systems to heat multiple rooms. Fireplace inserts are essentially wood stoves that are designed to be inserted into an existing fireplace cavity. Because of the heat transfer shielding effect of the fireplace cavity and the fact the majority of existing fireplace chimneys are against an outside wall, their heating efficiency is less than a similar freestanding woodstove. Many fireplace inserts have fans to facilitate transfer of heat from the portion that is inside the fireplace cavity. Both freestanding cordwood stoves and fireplace inserts rely on a natural draft using room air for combustion and the venting of exhaust through the chimney to the atmosphere. Though the majority of cordwood heaters use room air for combustion, some insert installations, such as in mobile homes, require the use of outside air for combustion.

Uncertified Conventional Cordwood-Fired Stoves and Fireplace Inserts
Uncertified cordwood fired stoves and fireplace inserts include units manufactured before the 40 CFR Part 60, Subpart AAA New Source Performance Standard (NSPS) July 1, 1990 certification requirement, and currently or recently manufactured exempt units which operate similarly to some old pre-EPA certification units.

NSPS Certified Catalytic Cordwood-Fired Stoves and Fireplace Inserts
Certified catalytic units pass the exhaust through a catalyst to achieve emission reductions. Generally, a coated ceramic honeycomb catalyst is located inside the stove where the incompletely combusted gases and particles ignite and are combusted further, thus reducing air emissions and increasing combustion overall efficiency.

NSPS Certified Non-Catalytic Cordwood-Fired Stoves and Fireplace Inserts
Certified non-catalytic stoves and fireplace inserts rely on design features to reduce air emission and increase efficiency. They generally rely on the introduction of heated secondary air to improve combustion, as well as firebox insulation, and baffles to produce a longer, hotter gas flow path, as well as other design features to achieve low emissions and higher efficiency.

Pellet Stoves and Fireplace Inserts

Analogous to cordwood stoves and fireplace inserts, pellet stoves and fireplace inserts are considered room heaters. They burn pellets generally made from sawdust, although there has been, and continues to be, research into utilizing other biomass fuels to make pellets. Combustion air is drawn from the room for most models, and exhaust is vented outdoors. Some pellet appliances use outside air for combustion. Pellet stoves and inserts require the use of electric motors to power the combustion air and heat transfer fans and the pellet-feeding auger. Modern pellet units use electronic sensors and controls. Pellets are introduced into the hopper, and the auger continuously feeds a consistent amount of pellets into the firebox. The feed rate is controlled electronically by a feed rate setting selected by the user. There are two basic designs: bottom-feed and top-feed models. Pellet units have a high efficiency and low emissions due to the use of the electric auger and fan that produce uniform and controlled combustion conditions. Some units are certified by the NSPS process and some are not. The performance of the certified and uncertified models are similar. What is considered by most as a "loop-hole" in the NSPS regulations essentially allows certification to be bypassed.

Wood-burning Fireplaces without Inserts

Fireplaces without inserts include manufactured units (often referred to as "zero-clearance" fireplaces) and site-built masonry units operated both with and without glass doors. Combustion air is drawn from the natural draft created by fire, and that same draft vents the exhaust gases through the chimney. Fireplaces without inserts have low efficiencies due to the large amount of heated room air that is exhausted out of the chimney from the draft. Many fireplaces without inserts are not used in a given year, some are used for aesthetic purposes and some are used for heating. Those that are used for heating are almost always used for secondary heating purposes and not primary heating due to their low efficiency and lack of heat transfer capabilities. Manufactured wax/fiber firelogs are often used as a fuel in them with about 30% of fireplace users nationwide claiming that they use wax/fiber firelogs some of the time. Most fireplaces are wall-mounted, however, this category also includes some free-standing models.

Direct Vent Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

Direct vent gas stoves and inserts are sealed units that draw their combustion air from, and vent their exhaust to, the outside air. Venting can be extended vertically or horizontally out of the home. A common type of venting is coaxial, which has the exhaust pipe contained within the air inlet pipe, so the temperature of the combustion air is raised, and the temperature of the exhaust is lowered, creating more efficient combustion. It should be noted that natural gas is not readily available in all locations, however LPG may be available for use.

Vent-Free Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

Vent-free gas stoves and inserts receive their combustion air from the room in which the unit is placed, and all of the products of combustion are exhausted into the room as well. The high efficiency of vent free units is due to the fact that the heat produced is kept in the room. Vent free gas stoves and inserts have a maximum heat input in order to avoid emitting excess CO, CO_2, or NO_X into the room, and the units also have an O_2 depletion sensor or other device to shut the unit down if oxygen levels become too low. It is important to note that vent-free natural gas and LPG stoves, inserts and log sets should not be considered options for primary or even significant secondary heating use. There is considerable concern regarding indoor air quality and damage to homes by moisture created from their use, as combustion gases are not vented to the atmosphere. If the devices are used prudently, these problems are reduced. Their appropriate role is for aesthetics and minor secondary heating. Just as with direct vent gas stoves and fireplace inserts, LPG can be used as an alternative where natural gas is not readily available.

B-Vent Gas Stoves and Fireplace Inserts (LPG and Natural Gas)

B-vent gas stoves and inserts draw their combustion air from the room, and exhaust is vented outdoors. These units use a draft hood for the proper venting of exhaust. B-vent gas stoves and inserts have lower efficiency than direct vent due to the fact that already heated room air is used as combustion air, which is then exhausted to the outdoors, taking heat away from the room.

OMNI Study Summary

In the OMNI study, the amount of fuel consumed by RWC devices was considered the measure of activity. Activity data were provided by individual appliance type by State and for the total MANE-VU region. The activity study conducted by OMNI showed that there were approximately 6.4 million tons of fuel burned in 2002 by RWC devices in the MANE-VU region. The majority of RWC combustion was located in New York (1.9 million tons of fuel burned) and Pennsylvania (1.4 million tons of fuel burned).

OMNI then compiled an emissions inventory by county, by State, and for the entire MANE-VU region for the 2002 base year. The dry mass of fuel (activity) for cordwood, pellets, and manufactured wax/fiber firelogs compiled in the activity task was multiplied by the applicable emission factor in the units of mass air pollutant per mass of dry fuel. The emission factors were obtained by reviewing and averaging (if multiple sources were available) data obtained from available reports and publications. PM and VOC (an ozone precursor) are the main criteria pollutants of concern for RWC and non attainment areas. The OMNI emissions inventory reported that there were 92,470 tons of total PM emissions and 87,741 tons of VOC generated from RWC devices in the MANE-VU region during the base year (2002). It should be noted that this analysis assumed that PM_{10} was equivalent to PM. The only emissions control efficiency, and control device information available is for PM_{10}. We have therefore assumed that data for PM_{10} are applicable to $PM_{2.5}$.

Table 9.1 from the OMNI report summarizes measures for RWC RACM developed by EPA in EPA-450/2-89-015. OMNI reported the RACM fall in three primary categories: (1) improvement of performance, (2) reducing the use of RWC devices, and (3) episodic curtailment. The effectiveness in reducing RWC emissions and a related discussion of each of the various activities are also provided in Table 9.1. In addition to the three primary categories for RWC RACM, the RACM document emphasizes the importance of public awareness in many RWC emission control programs and provides considerable information on the subject.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	Estimated Effectiveness (%)	Discussion
IMPROVEMENT OF PERFORMANCE		
State implementation of NSPS	0	States are not expected to adopt this program element at levels that would affect program effectiveness significantly.
Ban on resale of uncertified devices	0	No credit recognized because requirement is largely unenforceable: other elements will be required to include disabling of retired used devices.
Installer Training Certification or Inspection Program	~ 5	Reduction in emissions from each new certified RWC device where either the installer is trained/certified or the installation is inspected.
Pellet stoves	90	Reduction in emissions from each new or existing conventional, uncertified RWC device replaced with a pellet stove.
	75	Reduction in emissions from each new or existing Phase II EPA certified RWC device replaced with a pellet stove.
EPA Phase II certified RWC devices	~50	Reduction in emissions from each new or existing conventional, uncertified RWC device replaced with an EPA Phase II certified RWC device.
Retrofit requirement	<5	Reduction in emissions from each existing conventional, uncertified RWC device equipped with a retrofit catalyst or pellet hopper (to maximum when all existing uncertified RWC devices have retrofit devices installed).
Accelerated changeover requirement	~50	Reduction in emissions from each existing conventional, uncertified RWC device replaced with Phase II certified device.
	100	Reduction in emissions from each existing conventional, uncertified RWC device removed and not replaced: requires existing device to be disabled and not resold.
Accelerated changeover inducement	~50	Reduction in emissions from each existing conventional, uncertified RWC device replaced with Phase II certified device.
	100	Reduction in emissions from each existing conventional, uncertified RWC device removed and not replaced: requires existing device to be disabled and not resold.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	Estimated Effectiveness (%)	Discussion
Require fireplace inserts	0	No credit recognized for fireplace inserts, since inserts change use of fireplace from aesthetic to primary heat source, resulting in an increase in amount of wood combusted and higher overall emissions.
Wood moisture	<5	Reduction in total emissions from all RWC devices in the community/airshed.
Trash burning prohibition	0	No credit recognized for eliminating trash burning in RWC devices.
Weatherization of residences	<5	Reduction in total emissions from all RWC devices in the community/airshed.
Opacity limits	<5	Reduction in total emissions from all RWC devices in the community/airshed.
REDUCING USE OF RWC DEVICES		
Availability of alternative fuels	100	Reduction in emissions from each RWC device removed from service and replaced with device using natural gas: recognize no more than 10% of RWC devices replaced under program with no additional incentives.
Emission trading	Computation required	For a 2:1 trading ratio, the reduction in emissions from each new stove would be calculated as the difference between emissions of a new RWC device and 2 times the average emissions per stove in the community: multiplier would change for other trading ratios.
Taxes on RWC devices	Variable	Emission reduction credit would vary with utility or tax rate structure adopted and extent to which this structure resulted in reduction in number of RWC devices in the community versus reduction in use of RWC devices.
Regulatory ban on RWC devices in new dwellings	100	Reduction in emissions from new RWC devices purchased for installation in new dwellings.
Regulatory ban on existing RWC devices	100	Reduction in emissions from each RWC device removed.

Table 9.1 Summary of Measures Available for RWC RACM – PM_{10}

Program Elements	Estimated Effectiveness (%)	Discussion
EPISODIC CURTAILMENT		
Voluntary	10	Reduction in emissions for all RWC devices not exempted.
Mandatory	60% fireplace 50% woodstoves	Reduction in emissions for all RWC devices not exempted.

Table Reference: U.S. EPA, 1992, *Technical Information Document for Residential Wood Combustion Best Available Control Measures*, Research Triangle Park, NC, EPA-450/2-92-002.

Table 9.2 from the OMNI report summarizes measures for RWC BACM developed by EPA in EPA-450/2-92-002. As shown in Table 9.2, the BACM fall into two primary categories: (1) integral measures which are necessary for the success of a long-term RWC pollutant reduction programs but, by themselves, are not adequate to provide long-term reductions and (2) flexible (long-term) measures to reduce, eliminate, or prevent increases in pollutant emissions for existing and/or new installations. With the exceptions of the device and upgrade offsets, the specific elements of the BACM are essentially those described in the RACM document with the various efficiencies listed in Table 9.1 being applicable.

Table 9.2 Summary of Measures Available for RWC BACM – PM_{10}

Integral Measures[1]	Flexible Measures that Reduce or Eliminate Emissions from Existing Installations[2]	Flexible Measures that Reduce Emissions or Prevent Emission Increases from New Installations[2]	Flexible Measures that Reduce Emissions from New and Existing Installations[2]
1. Public awareness and education.	1. Conversion of existing wood-burning fireplaces to gas logs.	1. Gas fireplaces or gas logs in new wood burning fireplace installations.	1. Device offset.[4]
2. Mandatory curtailment during predicted periods of high PM_{10} concentrations.	2. Changeover to EPA certified, Phase II stoves or equivalent.	2. Upgrade offset.[4]	2. Upgrade offset.[4]
3. All new stove installations EPA-certified, Phase II stoves or equivalent.	3. Changeover to low emitting device.[3]	3. Restriction on number and density of new wood-burning stove and/or fireplace installations.	

Table 9.2 Summary of Measures Available for RWC BACM – PM_{10}

Integral Measures[1]	Flexible Measures that Reduce or Eliminate Emissions from Existing Installations[2]	Flexible Measures that Reduce Emissions or Prevent Emission Increases from New Installations[2]	Flexible Measures that Reduce Emissions from New and Existing Installations[2]
4. Measures to improve wood burning performance: -control of wood moisture content -weatherization of homes with wood stoves -educational opacity program		4. Requirement that new stove installations be low emitting.	

[1] Integral measures are regarded as critical for the success of a RWC control program, but by themselves are not intended to result in long-term attainment of the PM_{10} NAAQS for serious PM_{10} nonattainment areas.

[2] Flexible measures are designed for permanent control of RWC emissions and thus long-term attainment of the PM_{10} NAAQS.

[3] This measure is virtually identical to item 2, except that the changeover is recommended to a "low-emitting" device that can document "in-home" field test emissions less than the emission factor averages of "in-home" field test emissions data for EPA-certified stoves. This can include classes of devices that are demonstrated to be capable as a class of producing lower field emissions, as well as, specific model units that perform better in the field than the class collectively (an example might include masonry heaters, uncertified pellet-fueled devices, and wood fired gasification centralized heating systems).

[4] Offsets are intended to achieve emission reductions, when retiring (device offset) or changing-out (upgrade offset) conventional stoves, greater than the emissions increase resulting from new stove installations.

Table Reference: U.S. EPA, 1992, *Technical Information Document for Residential Wood Combustion Best Available Control Measures*, Research Triangle Park, NC, EPA-450/2-92-002.

OMNI reported that the RWC RACM and BACM have been the basis for PM_{10} innovative strategies implemented in various western States and in local jurisdictions and have also been, in-large part, the basis for a number of western State and their local RWC regulations. As part of these strategies, strict particulate emission standards have been developed which will take effect in 2008.

The OMNI report states that the Washington State standard is notable among State and local regulations for residential wood burning devices. Washington State has implemented more stringent standards for residential wood burning devices, so devices installed in Washington State must be certified to the more stringent standard. This has affected the stove market because many U.S. certified stove manufacturers choose to have their appliances certified to the more stringent Washington State standard, unless the manufacturer can not or does not choose to test to the tighter standard. Discussions with EPA indicate that most manufacturers are choosing to design and sell units that meet the Washington State standards of 4.5 g/hr for non catalytic wood stoves and 2.5 g/hr for catalytic wood stoves (personal communication with Mr. John Dupree of the U.S. EPA).

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR RESIDENTIAL WOOD COMBUSTION

Cost of Compliance

OMNI analyzed the cost effectiveness of five categories of widely existing, older technology wood-burning devices. These are: (1) freestanding cordwood stoves, (2) cordwood-fueled fireplace inserts, (3) cordwood fireplaces (without inserts) used for heating purposes, (4) centralized cordwood heating systems and (5) cordwood fireplaces used for aesthetic purposes. Table 9.3 lists these five categories with the available, improved technology replacement, installation scenarios, and fuel switching alternatives that would reduce particulate and VOC emissions.

OMNI noted that wood resources are abundant and widely utilized as fuel, and heating is essential due to the climate of the region. The cost to households of any regulatory program mandating acceptable heating practices is an important consideration. Likewise, the cost to households of any voluntary program is paramount for its success. The cost effectiveness of all reasonable scenarios for the replacement, modification or alternative fuel use for older existing, high emission wood-burning appliances was provided in the OMNI report for regulators and policy makers charged with the task of specifically lowering particulate and VOC emissions from residential wood combustion.

The tables provided in this chapter based on the OMNI report allow for a direct comparison of the cost burden for each realistic mitigation option that would be shouldered by residential users. As an example, for an average resident in the MANE-VU region with an existing older technology centralized cordwood heating system, the best current option in terms of cost among the pellet, natural gas, and LPG options, is natural gas (assuming natural gas is available). Similarly, for wood-burning fireplaces used for aesthetics, manufactured wax/fiber firelogs offer the lowest cost per unit mass of air pollutant reduction. The cost effectiveness of each option is dependent on the costs of the new equipment and the cost of required fuels. The costs presented in the tables in this chapter were the most current information available as of the date of the OMNI report.

Estimates of costs per ton of reductions in the tables in this chapter are specific to the MANE-VU region because they reflect the estimated usage of various devices in this region.

Table 9.3 Improved Technologies and Fuel Alternatives

Existing Cordwood Device	High Technology Replacement, Installation or Alternative Fuel
Uncertified Freestanding Cordwood Stove	Replacement with Certified NSPS Non-Catalytic Cordwood Stove
	Replacement with Certified NSPS Catalytic Cordwood Stove
	Replacement with Pellet Stove
	Replacement with Gas Stove – natural gas (B vent, direct vent)
	Replacement with Gas Stove – LPG (B vent, direct vent)
Uncertified Cordwood Fireplace Insert	Replacement with Certified NSPS Non-Catalytic Cordwood Insert
	Replacement with Certified NSPS Catalytic Cordwood
	Replacement with Pellet Insert
	Replacement with Gas Insert – natural gas (B vent, direct vent)
	Replacement with Gas Insert – LPG (B vent, direct vent)
Cordwood Fireplace without Insert Used for Heating	Installation of Certified NSPS Non-Catalytic Cordwood Insert
	Installation of Certified NSPS Catalytic Cordwood Insert
	Installation of Pellet Insert
	Installation of Gas Insert – natural gas (B-vent, direct vent)
	Installation of Gas Insert – LPG (B-vent, direct vent)
Cordwood Fireplace Used for Aesthetic Purposes	Installation of Gas Log Set – natural gas (vented and vent free)
	Installation of Gas Lo g Set – LPG (vented and vent free)
	Wax/Fiber Firelog Fuel
Centralized Cordwood Heating System	Pellet Furnace or Boiler
	Gas Furnace or Boiler – natural gas
	Gas Furnace or Boiler – LPG

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Table 9.4 from the OMNI report demonstrates the cost effectiveness of replacing three types of cordwood stoves and fireplaces with devices that emit less PM. Table 9.5 from the OMNI report demonstrates the impact on cost effectiveness of the same replacements on VOC reductions. The cost effectiveness tables are in reference to the replacement of an existing RWC device, and do not include new construction.

In Tables 9.4 and 9.5, if the total annual cost of the improved technology and alternative fuel replacement or installation is less than the total annual cost of the existing device, and there is corresponding pollutant reduction after installation or replacement, then there is no cost for the pollution reduction, and the cell is marked as "**". The replacement options for which there is no cost may actually represent cost savings, and thus are the most cost effective options for replacement.

Table 9.4 PM Reduction Cost Effectiveness for Replacement of Existing Uncertified Freestanding Cordwood Stove/Insert and Cordwood Fireplace w/o Insert for Heating

Existing Cordwood Device	Certified NSPS Non-Catalytic Cordwood Stove	Certified NSPS Catalytic Cordwood Stove	Pellet Stove	Gas Stove-NG, B Vent	Gas Stove-NG, Direct Vent	Gas Stove-LPG, B Vent	Gas Stove-LPG, Direct Vent
	PM Reduction Cost Effectiveness ($/ton)						
Uncertified Freestanding Cordwood Stove	1,170	3,300	8,960	5,350	3,530	12,600	9,760
Uncertified Cordwood Fireplace Insert	**	**	5,180	1,910	**	8,980	6,040
Cordwood Fireplace w/o Insert for Heating	3,880	5,670	8,330	**	**	1,880	695

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**No cost for the pollution reduction.

Tables 9.4 and 9.5 indicate that OMNI estimated that in the MANE-VU region there are several options for reducing emissions from two of the above types of fireplaces that would reduce emissions at essentially no cost, due to fuel cost savings.

Table 9.5 VOC Reduction Cost Effectiveness for Replacement of Existing Uncertified Freestanding Cordwood Stove/Insert and Cordwood Fireplace w/o Insert for Heating

Existing Cordwood Device	Certified NSPS Non-Catalytic Cordwood Stove	Certified NSPS Catalytic Cordwood Stove	Pellet Stove	Gas Stove-NG, B Vent	Gas Stove-NG, Direct Vent	Gas Stove-LPG, B Vent	Gas Stove-LPG, Direct Vent
	VOC Reduction Cost Effectiveness ($/ton)						
Uncertified Freestanding Cordwood Stove	1,260	2,960	7,740	4,940	3,260	11,800	9,130
Uncertified Cordwood Fireplace Insert	**	**	4,480	1,760	**	8,410	5,640
Cordwood Fireplace w/o Insert for Heating	7,900	10,400	13,200	**	**	3,090	1,140

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**No cost for the pollution reduction.

Table 9.6 presents the cost effectiveness in terms of dollars per ton of PM reduction and VOC reduction for replacement of an existing centralized cordwood heating system with three available technologies. The cost effectiveness tables are in reference to the replacement of an existing RWC device, and do not include new construction. The most cost effective option is replacing the existing system with a natural gas furnace or boiler. This option is not feasible in areas that do not have access to natural gas, and the increase in costs associated with using LPG is significant.

Table 9.6 Reduction Cost Effectiveness for the Replacement of an Existing Centralized Cordwood Heating System

High Technology Replacement, Installation or Alternative Fuel	PM Reduction Cost Effectiveness ($/ton)	VOC Reduction Cost Effectiveness ($/ton)
Pellet Furnaces and Boilers	7,810	17,200
Gas Furnaces and Boilers–Natural Gas	3,030	7,150
Gas Furnaces and Boilers-LPG	9,370	23,100

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region.* Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

Table 9.7 presents the cost effectiveness in terms of dollars per ton of PM reduction and VOC reduction for the addition of a gas log set or use of wax/fiber firelogs in an existing fireplace with no insert. Burning wax/fiber firelogs in the existing fireplace is, by far, the most cost effective option for reducing emissions of PM and VOC.

Table 9.7 Pollutant Reduction Cost Effectiveness for the Addition of a Gas Log Set or Use of Wax/Fiber Firelogs in an Existing Fireplace w/o Insert Used for Aesthetics

	Pollutant Reduction Cost Effectiveness ($/ton)				
Pollutant	**Vent-Free Gas Log Set-NG**	**Vented Gas Log Set-NG**	**Vent-Free Gas Log Set-LPG**	**Vented Gas Log-LPG**	**Wax/Fiber Firelog Fuel**
PM	27,100	29,900	29,400	34,100	2,530
VOC	43,900	48,500	48,300	56,600	5,110

OMNI Environmental Services, Inc. *Task 6, Technical Memorandum 4 (Final Report), Control Analysis and Documentation for Residential Wood Combustion in the MANE-VU Region.* Project funded by Mid-Atlantic Regional Air Management Association, Inc., December 19, 2006.

OMNI presented no cost-effectiveness summary for other RWC control measures such as described in EPA's PM_{10} RACM/BACM guideline documents. Costs associated with these measures are predominantly organizational and administrative associated with the implementation of regulations.

Time Necessary For Compliance

Because the control methods discussed in the previous section for RWC are existing technology, the time necessary for compliance would depend on the amount of time it would take to regulate the sources and establish compliance deadlines. The *Feasibility Assessment of a Change-out/Education Program for Residential Wood Combustion* from the Canadian Council of Ministers of the Environment suggests a phased approach for national implementation. A phased approach will enable the program to evolve over time and benefit from lessons learned in the early stages of the program. Phasing also reflects the reality that building awareness and changing behavior is a long-term investment. The approach that this report proposed had two phases. The first phase (2005-2006) focused on building a base for support and understanding around RWC in a single province. The second phase (2007 and beyond) and full roll-out involved the realization of independent, arms length management of public education and outreach by all stakeholders throughout Canada. The main steps for this phase included:

- Implementation of national regulation as soon as possible (i.e. 2008-2009);
- Full operational capacity across Canada;
- Funding to come from multiple sources (i.e. nationwide partnerships with the insurance, financial, and utilities industries);
- Movement of various groups from being target audiences to becoming key players in designing and delivering woodstove change-out/public education campaigns; and
- Multi-stakeholder involvement and shared leadership (governments together with business and industry, communities, and non-governmental organizations).

Energy and Non-Air Impacts

Other factors beyond $PM_{2.5}$ and regional haze (i.e., VOC and fine particles) should also influence RWC regulatory policy. The greenhouse gas benefits of biomass combustion and the minimal acid gas emissions (acid precipitation impacts) from wood combustion are strong environmental advantages. Further, the fact that wood is a domestic renewable energy source and the fact that the cost of natural gas, propane, and fuel oil have a history of rising together have been responsible for the increase in the use of RWC. For example, several States are encouraging the use of renewable energy sources such as wood for heating purposes.

The Canadian Council of Ministers of the Environment study estimated that the increase in combustion efficiency associated with a switch out to a more efficient stove would save on average more than one cord of wood per stove per heating season.

Any mandatory change out program should be mindful that even with assistance, woodstove change out programs will impact families that are least able to bear the burden of additional costs. Voluntary programs do not impose this economic burden on families less able to bear associated costs.

Remaining Useful Life Of The Source

From information obtained from a scoping study that was prepared for Environment Canada in 1997, (Gulland Associates Inc., 1997) the durability of low emission stoves has improved considerably. Premature stove degradation is not viewed as a problem. In most new stoves today, vulnerable parts can be replaced, and manufacturers now use more heat-resistant materials such as ceramics and stainless steel. The performance and durability of catalytic stoves has also improved through better design and use of materials. The useful life of a wood stove catalytic element is estimated to be 9,000 to 12,000 hours, or three to five years of use, depending on heating demand, user skill, and degree of maintenance provided.

The best mechanism by which to lower smoke emissions from residential wood burning appliances is to replace conventional equipment with certified low emission stoves. Given the minimum useful life span of a wood stove of 10-15 years (per industry references), over which time the incremental cost of advanced technologies is spread, the cost impacts did not seem unreasonable to Environment Canada. It is also possible that the price of the least expensive advanced technology stove would come down after a regulation were established as manufacturers seek to fill the low cost market niche formerly filled by conventional stoves; that is, plain, unadorned styling and lacking additional features such as ash pan and large glass door panel. (Gulland Associates Inc., 1997) Many woodstove manufacturers have chosen to manufacture products at a reasonable cost that meet more stringent emissions standards such as those in Washington State (personal communication with Mr. John Dupree of EPA). Implementation of stricter emissions standards in additional states or regions will likely increase the competition to produce these woodstoves at even more reasonable prices.

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CHAPTER 10

RESIDENTIAL WOOD COMBUSTION - OUTDOOR WOOD-FIRED BOILERS

BACKGROUND

Outdoor wood-fired boilers are used in the Northeast United States, and their use is increasing as more traditional heating fuels (heating oil, natural gas) are becoming more expensive. NESCAUM (2007) estimates that the sale of outdoor wood-fired boilers is increasing by 25-50% annually. Nationwide there are between 155,000 and 200,000 boilers in service (Personal communication with Lisa Rector, NESCAUM). If the sales trends continue, NESCAUM estimates that there may be up to 500,000 boilers nationally by 2010.

Outdoor wood-fired boilers are used for heating and providing hot water for both individual homes and for "mini-district heating" (Woodheat.org 2007). Additional uses of outdoor wood-fired boilers include heating swimming pools and greenhouses. Outdoor wood-fired boilers are typically located in sheds that are located near buildings. Heated water is conveyed through underground or insulated pipes.

Even though outdoor wood-fired boilers may be economical solutions to home heating and hot water production, they contribute significantly to air pollution. Outdoor boilers emit so much smoke they have been banned by some local jurisdictions (Woodheat.org 2007). NESCAUM (2007) estimates that the average fine particulate emissions from one outdoor wood-fired boiler are equivalent to the emissions from 22 US Environmental Protection Agency (EPA) certified wood stoves, 205 oil-fired furnaces, or 8,000 natural gas-fired furnaces.

On the basis of heat input, NESCAUM (2007) estimated that outdoor wood-fired boilers emit from 1.5 to 3.1 pounds of PM per MMBTU heat input. This information was calculated by NESCAUM using data from tests conducted on outdoor wood-fired boilers for EPA (EPA 1998a). (Guldberg 2007) used data from 56 outdoor wood-fired boilers tests conducted by EPA in 1995 and 1999, and estimated that outdoor wood-fired boilers emit 1.44 pounds of PM per MMBTU heat input. In comparison, the EPA estimate (EPA 1998b) for PM from residential fuel oil combustion is 0.4 pounds of PM per thousand gallons of fuel combusted. Assuming a heating value of 140 MMBTU per thousand gallons of fuel oil, the PM emission factor is 0.003 pounds of PM per MMBTU heat input for residential fuel oil combustion. Similarly, for residential natural gas combustion, (EPA 1998c) assuming a natural gas heating value of 1,020 BTU per standard cubic foot, the PM emission factor is 0.002 pounds per MMBTU heat input. Based on these emission factor estimates, and strictly on the basis of heat input, outdoor wood-fired boilers emit roughly 500 times as much PM as oil-fired residential furnaces and 750 times as much PM as natural gas-fired residential furnaces based on the low-range estimate of PM emissions from outdoor wood-fired boilers. Based on the upper range of the PM emissions estimate from outdoor wood-fired boilers, they emit roughly 1,000 times as much PM as oil-fired residential furnaces and 1,500 times as much PM as natural gas-fired furnaces.

Heavy emissions from outdoor wood-fired boilers can be attributed to their designs. For example, most outdoor wood-fired boilers have fireboxes that are surrounded by a water jacket. The water jacket makes complete combustion of the wood nearly impossible due to the cooling effect that the jacket has on the firebox. The flaming combustion of wood cannot occur below about 540 C (1,000 F), so the steel surfaces of the water jacket backed up by water at approximately 65 C (150 F) chill and quench the flames well before complete combustion can occur.

In addition outdoor wood-fired boilers smoke heavily due to their cyclical operating pattern. When the temperature of the water within the boiler falls below a set point, its combustion air damper opens and/or a small fan forces combustion air into the firebox. Once the water is heated back to the upper set point, the fan is turned off and/or the combustion air damper closes. During the off cycles the fire smolders and much of the smoke condenses as creosote on the cold steel internal surfaces. When the thermostat again calls for heat and incoming combustion air rekindles the fire, the heat ignites the creosote clinging to the boiler walls. This leads to an increase in emissions that accompanies the poor combustion in the firebox.

Outdoor wood-fired boilers are also sometimes not sized appropriately for the house that they are intended to heat. For example, an oversized boiler will tend to run in the smoldering phase longer than in the full out burn phase, thereby producing more smoke.

It has been suggested that excessive production of emissions by outdoor wood-fired boilers is associated improper installation of the boiler or the use of fuels not designed to be combusted in the boiler (personal communication with Peter Guldberg, Tech Environmental). Additionally, Guldberg, 2007 suggests that emissions from outdoor wood-fired boilers are comparable to other wood-fired combustion devices in terms of lbs/MMBTU heat generated. In any case, Guldberg, 2007 indicates that outdoor wood-fired boiler manufacturers have worked with EPA to develop a voluntary Outdoor Wood-fired Heater Program with a Phase I emission target of 0.6 lb/MMBTU. According to Guldberg, 2007 manufacturers will offer the outdoor wood-fired heaters qualified to achieve the Phase I standard later in 2007.

NESCAUM's Model Rule

On January 29, 2007, NESCAUM made available its "Outdoor Hydronic Heater Model Regulation." The model rule is designed to serve as a template to assist State and local agencies in adopting requirements that will reduce air pollution from outdoor wood-fired boilers. The model rule was developed in cooperation with a number of States and EPA. The model rule has provisions for:

- Critical definitions,
- Emission standards,
- Test method procedures,
- Certification process, and
- Labeling requirements.

The model rule contains a single method for regulating new units with respect to the critical elements and contemplates that States may propose alternative approaches for other provisions. It also provides alternatives for states to consider for regulating previously installed units (NESCAUM 2007).

NESCAUM's model rule sets standards for particulate matter (PM) emissions by phases for residential and commercial boilers. The PM standards for both boiler types are identical. Phase I calls for a PM emission limit or 0.44 pounds per million BTU heat input. This standard would have to be met by March 31, 2008. Phase II calls for a PM emission standard of 0.32 lb/MMBTU which is to be met by March 31, 2010.

Vermont's Rule on Outdoor Wood-fired Boilers

On April 12, 2007 Vermont filed a regulation on outdoor wood-fired boilers with the Secretary of State and the Legislative Committee on Administrative Rules. The rule legally went into effect on April 27, 2007, and adopts NESCAUM's model rule Phase 1 PM emission standard of 0.44 lb/MMBTU. As of March 31, 2008, outdoor wood-fired boilers not meeting the standard of 0.44 lb/MMBTU cannot be sold in Vermont. Additional information on Vermont's final rule on outdoor wood-fired boilers can be found on the following web site: http://www.vtwoodsmoke.org. (Etter, personal communication)

This section of this document addresses the four factor analysis which includes the following elements: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the source.

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR OUTDOOR WOOD-FIRED BOILERS

Cost of Compliance

Outdoor wood-fired boilers are priced according to their size (heat output). For example, Northwest Manufacturing sells a line of outdoor wood-fired boilers that ranges in price from \$4,295 for a boiler that will heat a 2,000 square foot house to \$12,995 for a boiler that can heat up to 20,000 square feet. Similarly, Hud-Son Forest Equipment has a line of outdoor wood-fired boilers that range in price from \$6,095 for boiler that can heat a 2,000 square foot house to \$7,795 for a boiler that can heat up to 10,000 square feet.

There are currently only a few outdoor wood-fired boiler manufacturers whose products would meet the 2008 NESCAUM phase I standard of 0.44 lb/MMBTU. NESCAUM estimates that there are "several units currently on the market that can meet this standard." In addition, NESCAUM estimates that more stringent air standards that it proposed should come into compliance in 2010 would currently only be met by one unit. Consequently, manufacturers of outdoor wood-fired boilers would have to invest money into research and development in order to manufacture boilers that would meet NESCAUM's model standards. MACTEC contacted an outdoor wood-fired boiler manufacturer to determine cost increases due to the NESCAUM rule. The boiler manufacturer was not able to provide estimated cost increases necessary to manufacture boilers meeting the NESCAUM model rule standards (personal communication with Central Boiler, Inc.).

MACTEC also investigated the costs of replacing the outdoor wood-fired boilers with heating oil-fired furnaces and boilers. We determined that the capital cost of oil-fired water boilers ranged from \$2,800 - \$3,825. Similarly, the capital cost of oil-fired furnaces range from \$1,560 -

$1,800 (Alpine Home Air 2007). Therefore, oil-fired boilers and furnaces can be substantially less expensive than outdoor wood-fired boilers.

In a previous section, information was presented on the average amount of distillate fuel oil used on an annual basis by households in the Northeast. It was estimated that households use approximately 865 gal/yr of fuel oil (STAPPA-ALAPCO 2006). Therefore, the annual average heating cost using fuel would currently be approximately $2,100 (assuming a fuel oil price of $2.40/gal). The University of Wisconsin Solid and Hazardous Waste Education Center (2007) estimates that it would take only 4 full cords of oak firewood to heat a house per year. At approximately $200/cord (Boston.com 2004), this equates to an annual fuel cost of $800/year. Consequently, the annual cost for firewood is $1,300 less than the cost of distillate fuel oil. Additionally, many operators of outdoor wood boilers have access to a free supply of firewood for the boiler, thus the only fuel cost to these operators is the time, effort, and expense associated with gathering the wood and cutting it for use in the outdoor wood-fired boiler.

Assuming the average household use of 865 gal/yr of fuel oil, and a fuel oil heating value of 140 MMBTU per thousand gallons, the annual heat input required is 121.1 MMBTU. The emission factors for residential fuel oil combustion, natural gas combustion, and wood combustion in outdoor wood-fired boilers are 0.003, 0.002, and 1.5 to 3.1 pounds of PM per MMBTU heat input respectively. Using the annual heat input requirement of 121.1 MMBTU, the annual emissions from an oil-fired furnace would be 0.4 pounds, the emissions from a natural gas-fired furnace would be 0.2 pounds, and the emissions from the outdoor wood-fired boiler would be from 180 to 380 pounds. The cost of replacing an outdoor wood-fired boiler with an oil-fired furnace or boiler is estimated to be from $1,560 to $3,825 (Alpine Home Air 2007). If the capital cost of the oil-fired furnace or boiler is spread over ten years, the annualized capital cost is between $156 and $383. Additionally, the cost of fuel oil is estimated to be from $0 to $2,100 more than the outdoor wood-fired boiler fuel costs depending on whether the operator has access to a free wood supply, or must purchase the wood by the cord. Based on these estimates, the PM cost effectiveness of replacing an outdoor wood-fired boiler with an oil-fired furnace or boiler would be from $1,700 to $13,000 per ton of PM reduced. The costs for replacement of outdoor wood-fired boilers with natural gas-fired furnaces or boilers have not been quantified.

Time Necessary for Compliance

Outdoor wood-fired boilers have been in operation for approximately the last 15 years (personal communication with P. Etter from Vermont Air Pollution Control). Consequently, the average age of outdoor wood-fired boilers is not known. On at least one occasion, a boiler vendor opted to go out of business rather than honor 5-year warranties (personal communication with J. Gulland from OutdoorHeat.org). If States pass a rule similar to NESCAUM's and existing boilers are grandfathered, only new boilers would be required to meet the more stringent standards. In the section on residential heating, it was estimated that the average useful life of a residential boiler is between 18-25 years. Well manufactured outdoor wood-fired boilers may have similar useful lives. Therefore, new boilers meeting more stringent PM emissions standards would be phased in slowly as older boilers are replaced.

Replacement of wood-fired boilers with oil-fired furnaces or boilers could occur on a very quick schedule. The number of residential boiler/furnace manufacturers in the United States is indicative of the fact that there is an ample supply of manufacturers. Although it is possible for outdoor wood-fired boilers to be replaced quickly, realistically, most of these units have been installed within the past 15 years. Since they are designed to last for approximately 20 years, operators of the outdoor wood-fired boilers would likely be reluctant to replace them immediately.

Energy and Non-Air Impacts

Wood is a renewable resource that is plentiful in the United States Northeast. The increased use of outdoor wood-fired boilers would lead to an increase in the amount of firewood that is combusted in the US Northeast on an annual basis. Alternatively, tighter rules regarding the PM emissions from outdoor wood-fired boilers may lead to a decrease in their use, which would make more firewood available for use in wood stoves and fire places. A move away from wood-fired boilers would increase the demand on heating fuels such as heating oil, propane, and potentially coal or natural gas.

The increased use of outdoor wood-fired boilers may have a variety of non-air impacts on the environment, especially on forest and water resources. The potential impacts are outlined below.

Nuisance Smoke: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities (Michigan DEQ 2007).

Water: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

Soils: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

Wildlife: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

Threatened and Endangered Species: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

Remaining Useful Life of the Source

The useful life of outdoor wood-fired boilers is approximately 20 years, which is also very close to the useful life of other residential boilers (Etter, personal communication). In addition, Mr. Etter indicated that outdoor wood-fired boilers have only been around for approximately 15 years, therefore, most of the boilers that have been put into service are likely to remain there for at least the next five years.

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ATTACHMENT Z

Assessment of Control Technology Options for BART-Eligible Sources

Assessment of Control Technology Options for BART-Eligible Sources

Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities

Prepared by
Northeast States for Coordinated Air Use Management
In Partnership with
The Mid-Atlantic/Northeast Visibility Union

March 2005

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Assessment of Control Options for BART-Eligible Sources

Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities

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March 2005

ASSESSMENT OF CONTROL OPTIONS FOR BART-ELIGIBLE SOURCES

STEAM ELECTRIC BOILERS, INDUSTRIAL BOILERS, CEMENT PLANTS, AND PAPER AND PULP FACILITIES

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Unit, Species, Acronyms

Acronyms
APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
CAA – Clean Air Act
CAAA – Clean Air Act Amendments
CKD – Cement Kiln Dust
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – ElectroStatic Precipitator
ESFF – Electrostatic Stimulation of Fabric Filtration
FBC – Fluidized Bed Combustion
FF – Fabric Filters (also known as baghouses)
FGD – Flue Gas Desulfurization (also known as scrubbers)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
ICR – Information Collection Request
LAER – Lowest Achievable Emission Rate
LNB – Low NO_X Burner
LSFO – Limestone Forced Oxidation
LSC – Low Sulfur Coal (also known as "compliance coal")
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic/Northeast Visibility Union
MC – Mechanical Collector
NCG – Non Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standard
NSR – New Source Review
OFA – Over Fire Air
PC – Pulverized Coal
PS – Particulate Scrubber
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SIP – State Implementation Plan
SCR – Selective Catalytic Reduction
SDA – Spray Dry Absorption
SNCR – Selective Non-Catalytic Reduction
SOG – Stripper Off Gases
TDF – Tire-Derived Fuel
US EPA – United States Environmental Protection Agency

Chemical Species
EC – elemental carbon
HSO_4 – bisulfate
H_2SO_4 – sulfuric acid
HNO_3 – nitric acid
NO_X – oxides of nitrogen (NO and NO_2)
NO – nitric oxide
NO_2 – nitrogen dioxide
NO_3 – nitrate
NH_3 – ammonia
$(NH_4)_3H(SO_4)_2$ – letovicite
NH_4HSO_4 – ammonium bisulfate
$(NH_4)_2SO_4$ – ammonium sulfate
NH_4NO_3 – ammonium nitrate
OC – organic carbon
$PM_{2.5}$ – particle matter up to 2.5 µm in size
PM_{10} – particle matter up to 10µm in size
PM_{coarse} – the difference: $PM_{10} - PM_{2.5}$
S – sulfur
Se – selenium
SO_2 – sulfur dioxide
SO_4 – sulfate
VOC – volatile organic carbon
VOM – Variable Operating and Maintenance Costs

Units

Length
m – meter
µm – micrometer (0.000001m; 10^{-6}m)
km – kilometer (1000 x m; 10^3 m)
Mm – Megameter (1000000 x m; 10^6 m)

Flow Rate
ACFM – Actual Cubic Feet per Minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
µg – micrograms (0.000001 x g; 10^{-6} g)
kg – kilograms (1000 x g; 10^3 g)

Power
W – watt (Joules/sec)
kW – kilowatt (1000 x W; 10^3 W)
MW – megawatt (1000000 x W; 10^6 W)

Energy
Btu – British Thermal Unit (= 1055 Joules)
mmBtu – million Btu
MWh – megawatt hour
kWh – kilowatt hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

Visibility
dv – deciview
km – visual range in kilometers
Mm^{-1} – extinction in inverse megameters

TABLE OF CONTENTS

Executive Summary

This report was prepared by the Northeast States for Coordinated Air Use Management (NESCAUM) as part of an effort to assist states and tribes as they prepare to comply with the Best Available Retrofit Technology Requirements (BART) of the Regional Haze Rule. The Haze Rule requires states to determine the most stringent technologically feasible system of controls that can reasonably be installed at each facility eligible for BART. Criteria that determine whether a specific control technology is deemed reasonable include: cost of the controls, other control technology in use at the source, energy and other non-air quality environmental impacts, remaining useful life of the source as well as the degree of visibility improvement anticipated to result from installation of the controls.

This assessment provides information on available technology options, control efficiency and typical installation costs for four important BART-eligible source categories in the MANE-VU region. These categories include Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input, Fossil-fuel boilers of more than 250 million British thermal units per hour heat input, Portland cement plants, and Kraft pulp mills. While there are 22 other source categories covered by the BART rule (with over 25 BART-Eligible facilities in at least 8 of these source categories in the MANE-VU region), we have chosen to focus on these four categories which include 75 of the 100 MANE-VU BART-Eligible sources identified at this time. *[Editors note: The addition of NY and PA non-EGU facilities will change these numbers]* These source sectors were chosen for a combination of factors including the number of facilities, the typical emission level for these type of facilities and the availability of a generic control technology characterizations for that sector. States will need to conduct an individual analysis for each facility prior to making a BART determination. This information is intended to facilitate that process by collecting available technology information in a single reference document.

The report finds that significant emissions reductions can be achieved through a variety of technologies that target different haze forming pollutants. While wet and dry scrubbing techniques may be cost-effective means of removing SO_2 at EGUs and large industrial boilers, combustion modifications and process changes might be more effective at cement plants and paper and pulp facilities. Similarly for NO_X control, SCR and SNCR are very efficient methods of post-combustion control that can be quite cost-effective on large boilers, but combinations of combustion and post-controls as well as combustion modification and process changes are also viable means of reducing a facility's total NO_X emissions. These approaches need to be carefully considered on a unit-by-unit basis, taking into account fuel used (coal, natural gas, oil, wood, etc.) and capacity or use factors, to ensure that product quality and pollutant co-control issues are handled appropriately. Particulate controls include a variety of technologies, but electrostatic precipitators and fabric-filters (or baghouses) are viable options in different configurations for EGUs, industrial boilers and cement plants. Paper and pulp facilities may also consider demister pads, packed tower technologies and Venturi scrubbers.

1. INTRODUCTION

Under the U.S. Environmental Protection Agency's (USEPA) 1999 "regional haze rule" [64 Fed. Reg. 35714 (July 1, 1999)], certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART).[1] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act (CAA).

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation or come into existence in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments (CAAA), which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically (i.e. through reasonably attributable visibility impairment requirements in the 1980 haze regulations). In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible, market-based approaches, provided such alternatives can be shown to achieve *greater* progress toward visibility objectives than the standard BART approach.

In developing future haze state implementation plans (SIPs), states and tribes will need to include an inventory of emissions from potentially BART-eligible facilities in their jurisdictions and specify the timetable and stringency of controls to be applied at those sources. In determining what level of control represents BART, states must address the following considerations for each eligible source or group of eligible sources:

- Compliance costs,
- Energy and non-air quality environmental impacts,
- Any existing pollution control technology in use at the source,
- The remaining useful life of the source, and
- The degree of visibility improvement that may reasonably be anticipated to result from the imposition of BART.

In many respects, the strength of the BART program is dependent upon the interpretation of these factors and in January 2001 USEPA proposed guidelines for the interpretation and implementation of Best Available Retrofit Technology (BART) requirements, including these factors. While no explicit threshold was established for

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

any of these factors, the publication of the BART guidelines as a proposed rule in the Federal Register [66 Fed. Reg. 38108 (July 20, 2001)] initiated a formal rulemaking process to clarify BART requirements specifically.

BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Haze Rule and the final BART regulations, anticipated to be published on April 15, 2005, gives urgency to understanding the implications of the final BART guidelines with respect to state planning efforts. Depending on a host of factors, BART may be the primary component of state haze plans or may be eliminated as a potential mechanism for state compliance.[2] Amid such uncertainty, states must continue to plan for the implementation of BART.

To assist MANE-VU states and tribes with BART implementation efforts, MANE-VU has developed a list of BART-eligible sources in the region (NESCAUM, 2001; NESCAUM, 2003).[3] The preliminary list developed in these documents has been refined by state permitting staff to verify identifications and determine eligibility for those sources for which incomplete information was available. The final, state-approved (i.e. each state has approved the list of sources within that state) list is available here as Appendix A. It should be noted that the review of the facilities for BART eligibility was performed prior to the release of the draft BART rule in 2004. Determinations were based upon the guidance provided in EPA draft rule released in 2001. It is anticipated that EPA will release a final BART rule in April 2005 and at that time final BART-eligibility determinations will be made. It is likely that there will be changes to the BART list based upon that final rule.

Once deemed BART-eligible, each source will undergo a BART engineering review to determine what system of controls constitutes BART for each facility. This review will examine impacts for all the BART pollutants. For example, if a facility triggeres BART because it has VOC emissions over 250 tons per year for date-eligible units, the facility will also have to examine the impacts of emissions of NO_X, SO_2, PM_{10} and ammonia, even if emissions of these pollutants are less than 250 tons per year.

In addition, this review must take into account the statutory factors cited earlier including remaining useful life of a source and controls already in place at a source. After review of these criteria and control options, the level of required control will be established. It is anticipated that the final rule will also address the specific aspects relating to the completion of a BART engineering analysis.

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[2] A number of factors in the pending BART regulation may affect the strength of the program. Among these are (1) a final decision on whether USEPA's Clean Air Interstate Rule (CAIR) could serve as BART for affected sources in states that choose this option, (2) final rules for how states may institute a source-by-source exemption test, (3) a decision on whether to aggregate emissions from multiple date-eligible boilers at a facility when comparing to the 250 ton/year emission threshold. An additional factor to consider is a provision contained in Senate Resolution 485 (the Clear Skies Act of 2003 which is expected to be re-introduced early in the 109th congress), which would act in place of the BART requirements of the regional haze rule.

[3] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and the identified sources are contained in the final list in Appendix A.

As a next step in coordinating BART determinations for MANE-VU states and tribes, we present here (in Chapters 3 through 6 of this report) a preliminary assessment of available control technology options for states to consider as they undertake the specific BART determinations for each of the eligible facilities in four major source categories including EGUs, industrial boilers, cement plants and paper and pulp facilities. These four categories cover 76 of the 101 BART-eligible facilities in MANE-VU.

While a facility specific review will need to be undertaken for each BART-eligibility (either to determine BART controls to be installed, or to determine the magnitude of emissions reductions that must be considered in a BART trading program), the information provided here will give states and tribes a foundation for conducting these reviews.

2. STEAM ELECTRIC PLANTS (EGUs)

Electricity Generating Units or EGUs are the largest source category among the twenty - six source categories covered by the Regional Haze Rule both in terms of total visibility impairing emissions and in terms of number of facilities. Estimates of national emissions for criteria air pollutants prepared by the USEPA show that electric utility power plants that burn coal are significant sources of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) (USEPA, 2000). Electric utility power plants are the nation's largest source of SO_2 emissions, contributing approximately 68 percent of the estimated total national SO_2 emissions in 1998 (most recent year for which national estimates are available). Over 90 percent of these SO_2 emissions are coal-fired electric utility boilers. Electric utilities contributed 25 percent of total national NO_X emissions in 1998. Again coal combustion is the predominant source of NO_X emissions from the electric utilities (almost 90 percent of the estimated NO_X emissions). Coal-fired electric utility power plants also are one of the largest industrial sources of PM emissions. In general, the high combustion efficiencies achieved by coal-fired electric utility boilers result in low emissions of CO and volatile organic compounds (a precursor for the photochemical formation of ozone in the atmosphere). Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO2 control and ESPs or baghouses for PM control for oil units).

All coal-fired electric utility power plants in the United States use control devices to reduce PM emissions. Many coal-fired electric utility boilers also are required to use controls for SO_2 and NO_X emissions depending on site-specific factors such as the properties of the coal burned, when the power plant was built, and the area where the power plant is located. Though there are other major stationary source sectors (for example, cement plants, paper and pulp plants, large industrial boilers, combustion turbines, iron and steel industry), coal-fired boilers are by far the largest contributor of all of these three precursors of regional haze.

2.1. Description of generation process and typical technologies

The USEPA ICR (Information Collection Request) of 1999 (the most recent and quite detailed survey of coal-fired EGUs in the U.S. completed in connection with USEPA efforts to develop MACT regulations for mercury from EGUs) indicates that there were about 1,140 coal-fired units in the U.S. (with a maximum capacity to generate in excess of 300,000 MW of power). This USEPA ICR data indicated that coal-fired steam electric generating units in the U.S. burned 786 million tons of coal of which, approximately 52 percent was bituminous and 37 percent was sub-bituminous. Other fuels included lignite, anthracite coal, reclaimed waste coal, mixtures of coal and petroleum coke (pet-coke), and mixtures of coal and tire-derived fuel (TDF). Pulverized coal-fired (PC) boilers represent approximately 86 percent of the total number and 90 percent of total utility boiler capacity. Based on capacity, other types of boilers include cyclone-fired boilers (7.6 percent), fluidized-bed combustors (1.3 percent), and stoker-fired boilers (1.0 percent).

2.2. Review of BART-Eligible EGUs in the MANE-VU Region

There are 53 BART-Eligible EGUs in the MANE-VU region. Table II-1 contains a summary list of these sources by state. A complete list is presented in Appendix A. Both lists are based on a previous NESCAUM report (2001) and follow-up review by state permitting authorities.[4] An estimated 1.2 million tons of SO_2 and three-hundred thousand tons of NO_X are emitted by these facilities and given the available control technology described in subsequent sections of this chapter, BART-Eligible EGUs represent a significant emissions reduction potential for consideration in the regional haze planning process.

Table II-1 BART-Eligible EGUs in the MANE-VU region. (NESCAUM, 2001).

State	Total Number of BART EGUs	Total SO_2 Emissions (1999 NEI)	Total NO_X Emissions (1999 NEI)
Connecticut	5	30,787	8,217
Delaware	3	10,490	4,465
District of Columbia	1	1,432	447
Maryland	6	177,678	63,767
Massachusetts	7	97,854	27,350
Maine	1	6,406	879
New Hampshire	2	37,834	7,043
New Jersey	1	17,260	7,891
New York	13	73,164	31,392
Pennsylvania	14	744,165	151,992
Penobscot Tribe	0	N/A	N/A
Rhode Island	0	N/A	N/A
St. Regis Mohawk Tribe	0	N/A	N/A
Vermont	0	N/A	N/A
Region Total	**53**	**1,197,070**	**303,443**

2.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for SO_2, NO_X, and primary PM emissions; the three major precursors of observed regional haze in the atmosphere (SO_2 and NO_X are mostly converted to ammonium sulfate and ammonium nitrate

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[4] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

that are formed by the reactions of precursor gases with ammonia in the environment that is emitted mostly from agricultural and cattle related activities). Most utilities control SO_2 by the use of either low-sulfur coal (generally less than 1 percent sulfur by weight) or by wet or dry scrubbing (known as flue gas desulphurization, or FGD). Generally, NO_X emissions are controlled via combustion modification and, more recently, by more advanced post-combustion controls, which are required by the 1990 Clean Air Act and state regulations ("NO_X Transport SIP Call" and the Title IV of the 1990 CAAA are two major examples). Compared to these two precursors, PM emissions are almost universally controlled in the U.S. (almost 100% of units have either electrostatic precipitators (ESPs) or fabric filters (FF) (popularly known as "bag houses"). Based on the 1999 USEPA's ICR (Information Collection Request) data, for post-combustion controls, 77.4 percent of the units have PM control only, 18.6 percent have both PM and SO_2 controls, 2.5 percent have PM and NO_X controls, and 1.3 percent have all three post-combustion control devices.

The different types of post-combustion control devices are briefly described below with detailed descriptions given later in this section:

SO_2 post-combustion control technologies are systems that are classified as wet flue gas desulfurization (FGD) scrubbers, semi-dry scrubbers, or dry injection. Wet FGD scrubber controls remove SO_2 by dissolving it in a solution. A PM control device is always located upstream of a wet scrubber. PM devices that may be used with wet FGD scrubbers include a Particulate Scrubber (PS), Cold Side (CS)-ESP, Hot Side (HS)-ESP, or a fabric filter (FF) or a baghouse. Semi-dry scrubbers include spray dryer absorption (SDA). Dry injection involves injecting dry powdered lime or other suitable sorbent directly into the flue gas. A PM control device (ESP or FF) is always installed downstream of a semi-dry scrubber or dry injection point to remove the sorbent from the flue gas.

NO_X post-combustion control technologies include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes. With both of these methods, a reducing agent such as ammonia or urea is injected into the duct to reduce NO_X to N_2. SCR operates at lower temperatures than SNCR and is much more effective at reducing NO_X, but it has higher capital costs for installation.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called "baghouses"), and particulate scrubbers (PS). ESPs and FFs may be classified as either cold-side (CS) devices [installed upstream of the air heater where flue gas temperatures range from 284 to 320 °F (140 to 160 °C)] or hot-side [installed downstream of the air heater and operate at temperatures ranging from 662 to 842 °F (350 to 450 °C)].

For PM controls, ESPs are used on 84 percent of the existing electric utility coal-fired boiler units, and fabric filters or baghouses are used on 14 percent of the utility units. Post-combustion SO_2 controls are less common. Wet flue gas desulfurization (FGD) systems are used on 15.1 percent of the units; and, dry scrubbers, predominantly spray dryer absorbers (SDA), are used on 4.6 percent of units that were surveyed. However, since it is generally more cost effective to install scrubbers on big units, the 20 percent of the units represent about 30% of the installed U.S. capacity. In response to the "Section 110 Transport SIP call" and the implementation of the Federal Title IV acid rain program, the application of post-combustion NO_X controls is becoming more prevalent. For example, based on the current status of electric utility industry, it appears that one third of the coal-based capacity (about 100,000 MW out of the installed base of about 300,000 MW) has been or is currently being retrofitted with the advanced SCR technology .

2.3.1. Emission Characteristics of Regional Haze Precursors from Coal Combustion

Sulfur Dioxide

SO_2 emissions, mostly from the combustion of fossil fuels and by metallurgical processes, are the result of oxidation of sulfur in the coal during the combustion process. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as eight percent or more. Most of this sulfur is present as either pyritic sulfur (sulfur combined with iron in the form of a mineral that occurs in the coal deposit) or organic sulfur (sulfur combined directly in the coal structure). During combustion, sulfur compounds in coal are oxidized to gaseous SO_2 or SO_3. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, ninety eight percent). The more alkaline nature of ash in some subbituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. Generally, the percentage of sulfur in the as-fired coal that is converted to sulfur oxides during combustion does not vary with the utility boiler design or operation. (USEPA, 1982; Buonicore and Davis, 1992).

Nitrogen Oxides

The NO_X formed during coal combustion by oxidation of molecular nitrogen (N_2) in the combustion air is referred to as "thermal NO_X." The oxidation reactions converting N_2 to NO and NO_2 become very rapid once gas temperatures rise above 1,700°C (3,100°F). Formation of thermal NO_X in a coal-fired electric utility boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above 1,700 °C, the gas residence time at these temperatures and the quantity of excess combustion air affects thermal NO_X formation. The formation of NO_X by oxidation of nitrogen compounds contained in the coal is referred to as "fuel NO_X." The nitrogen content in most coals ranges from approximately 0.5 to 2 percent. The amount of nitrogen available in the coal is relatively small compared with the amount of nitrogen available in the combustion air. However, depending on the combustion conditions, significant quantities of fuel NO_X can be formed during coal combustion. (USEPA, 1991; Buonicore and Davis, 1992).

Both NO and NO_2 are formed during coal combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the coal. Overall, total NO_X formed during combustion is composed predominantly of NO mixed with small quantities of NO_2 (typically less than 10 percent of the total NO_X formed). However, when NO is formed during coal combustion, the NO is oxidized to NO_2 and is emitted to the atmosphere.

Particulate Matter

Primary PM emissions from coal-fired electric utility boilers consist primarily of fly ash. Ash is the unburned carbon char and the mineral portion of combusted coal. The amount of ash in the coal, which ultimately exits the boiler unit as fly ash, is a complex function of the coal properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone furnace boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs may also promote ash vaporization and larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from coal-fired EGUs result from reactions of the SO_2 and NO_X compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO_2 and NO_X compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO_3), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned coal) contained in the fly ash. In general, the high combustion efficiencies achieved by pulverized-coal-fired boilers and cyclone-fired boilers result in relatively small amounts of unburned carbon particles in the exiting combustion gases. Those pulverized-coal-fired electric utility boilers that use special burners for NO_X control tend to burn coal less completely; consequently, these furnaces tend to emit a higher fraction of unburned carbon in the combustion gases exiting the furnace.

Another potential source of PM from coal-fired EGUs can be found in the flue gas and the use of a dry sorbent-based control technology. Solid sorbent particles are injected into the combustion gases to react with the air pollutants and then recaptured by a downstream control device. Sorbent particles that escape capture by the control device are emitted as PM to the atmosphere. (USEPA, 1982; Buonicore and Davis, 1992).

2.3.2. Control Technologies used for Coal-fired EGUs

In addition to BART requirements, all EGUs in the U.S. must comply with applicable federal and state standards and programs that specifically regulate criteria air emissions from coal-fired electric utility boilers. The federal regulations and programs include New Source Performance Standards (NSPS), the CAA Title IV Acid Rain Program, the 1997 "Transport NO_X SIP call," and the CAA Title V Operating Permits Program. The USEPA has delegated authority to individual state and local agencies for implementing many of these regulatory requirements

Additionally, some of the states in the Northeast, including Connecticut, Massachusetts, New Hampshire, New Jersey, and New York, have recently implemented new regulations or legislation that are more stringent than the federal requirements. Electric utility companies use one or a combination of the following three control strategies to comply with the specific set of requirements applicable to a given coal-fired boiler.

Pre-combustion Controls. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.

Combustion Controls. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.

Post-combustion Controls: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Table II-2 shows the national distribution of emissions control strategies for SO_2, NO_X, and PM used for coal-fired electric utility boilers in 1999 as reported in the Part II USEPA ICR data (USEPA, 2001). Approximately two-thirds of the total coal-fired electric utility boilers use either a low-sulfur fuel or a post-combustion technology (a wet or a dry scrubber) to control SO_2 emissions. The methods used for controlling SO_2 emissions from EGUs are discussed first. All coal-fired electric utility boilers in the United States are controlled for PM emissions by using some type of post-combustion controls. These particulate emission control types are discussed next. Although approximately two-thirds of the coal-fired electric utility boilers are controlled for NO_X emissions, these units are not necessarily the same units controlled for SO_2 emissions. The predominant strategy for controlling NO_X emissions is to use combustion controls. Later in this section, the application of NO_X emission controls to coal-fired electric utility boilers is described in detail.

Table II-2 Criteria air pollutant emission control strategies as applied to coal-fired electric utility boilers in the United States for the year 1999 (USEPA, 2001).

Criteria Air Pollutant	Percentage of Coal-fired Electric Utility Boilers Using Control Strategy as Reported in Phase II USEPA ICR Data a,b			
	Meet Applicable Standards Without Additional Controls	Pre-combustion Controls	Combustion Controls	Post-combustion Controls
Particulate Matter	0 %	0 %	0 %	100 %
Sulfur Dioxide	37 %	40 %	3 %	20 %
Nitrogen Oxides	40 %	0 %	57 %	3 %

(a) Approximately 1.5 % of the boilers use a combination of pre-combustion and post-combustion SO_2 controls.

(b) Approximately 1% of the boilers using post-combustion NO_X controls also use some type of combustion controls.

SO_2 Emission Controls

Sulfur dioxide emissions from most coal-fired electric utility boilers are controlled using either of two basic approaches. The first approach is to use pre-combustion measures, namely, firing coal that contains lower amounts of sulfur. The low-sulfur coal may be naturally occurring or the result of coal cleaning. The other approach is to remove the sulfur compounds from the flue gas before the gas is discharged to the atmosphere. These post-combustion processes are collectively called "flue gas desulfurization" or "FGD" systems. All FGD systems can be further classified as wet or dry flue gas scrubbing systems. The SO_2 control approaches include a number of different technology subcategories that are now commercially used in the United States, Europe, or Pacific Rim countries.

Table II-3 presents the 1999 nationwide distribution of SO_2 controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. For approximately one-third of the boilers, no SO_2 controls were reported in the Part II USEPA ICR data. The other two-thirds of the units reported using some type of control to meet the SO_2 emission standards applicable to the unit. Pre-combustion control by burning a low-sulfur content coal was reported for approximately 40 percent of the boilers. Post-combustion control devices for SO_2 removal are used for approximately 20 percent (representing 30% of the capacity in megawatts) of the boilers. Wet FGD systems are the most commonly used post-combustion control technique. The newer technologies of spray dryer systems or dry injection are limited in their application to existing units. The remaining 3 percent of the boilers use fluidized-bed combustion (FBC) with limestone.

Low-sulfur Coal

Coal with low sulfur content can be burned and meet applicable SO_2 emission standards without the use of additional controls is sometimes referred to as "compliance coal." Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Table II-3 Nationwide distribution of existing SO_2 emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

SO_2 Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Burn low-sulfur coal (“compliance coal”)	LSC	455	39.9 %	38.2 %
Wet FGD system	FGD	173 (a)	15.2 %	23.8 %
Spray dryer system	SDA	52 (b)	4.6%	3.4 %
Fluidized-bed coal combustion with limestone	FBC	37 (a,c)	3.2%	1.1 %
Dry injection	DI	2	0.2 %	< 0.1 %
No controls reported (d)		421	36.9 %	33.5 %
Nationwide Total		1,140 (e)	100 %	100 %

(a) Includes one FBC boiler unit using a wet FGD system.
(b) Includes three FBC boilers using spray dryer systems.
(c) FBC boilers using no downstream post-combustion SO_2 controls.
(d) Entry in ICR response indicated none or was left blank.
(e) Does not include the three IGCC units.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

Wet FGD Systems

The SO_2 in flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. These processes are called "wet FGD systems" in this report. Most wet FGD systems for control of SO_2 emissions from coal-fired electric utility boilers are based on using either limestone or lime as the alkaline source. At some of these facilities, fly ash is mixed with the limestone or lime. Several other scrubber system designs (e.g., sodium carbonate, magnesium oxide, dual alkali) are also used by a small percentage of the total number of boilers.

The basic wet limestone scrubbing process is simple and is the type most widely used for control of SO_2 emissions from coal-fired electric utility boilers. Limestone sorbent is inexpensive and generally available throughout the United States. In a wet limestone scrubber, the flue gas containing SO_2 is brought into contact with limestone/water slurry. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge, mostly calcium sulfite hemihydrate and gypsum, is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct.

The wet lime scrubber operates in a similar manner to the wet limestone scrubber. In a wet lime scrubber, flue gas containing SO_2 is contacted with hydrated lime/water slurry; the SO_2 is absorbed into the slurry and reacts with hydrated lime to form an insoluble sludge. The hydrated lime provides greater alkalinity (higher pH) and reactivity than limestone. However, lime-scrubbing processes require appropriate disposal of large quantities of waste sludge.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95 percent. For both types of wet scrubbers, operating parameters affecting SO_2 removal efficiency include liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of calcium sorbent to SO_2. Periodic maintenance is needed because of scaling, erosion, and plugging problems. Recent advancements include the use of additives or design changes to promote SO_2 absorption or to reduce scaling and precipitation problems.

Spray Dryer Absorber

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubbers) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). For the spray dryer absorber process, the combustion gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 to 180 °C (250 to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas, along with fly ash, and are collected in a PM collection device. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices, especially fabric filters. This process produces dry reaction waste products for easy disposal.

The primary operating parameters affecting SO_2 removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To increase overall sorbent use, the solids collected in the spray dryer and the PM collection device may be recycled. The SO_2 removal efficiencies of existing lime spray dryer systems range from 60 to 95 percent.

Dry Injection

For the dry injection process, dry powdered lime (or another suitable sorbent) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO_2 removal efficiencies of existing dry injection systems range from 40 to 60 percent.

Circulating Fluidized-bed Absorber

In the circulating fluidized-bed absorber (CFBA), the flue gas flows upward through a bed of sorbent particles to produce a fluid-like condition in the bed. This condition is obtained by adjusting gas flow rate sufficiently to support the particles, but not carry them out of the system. Characteristics of the bed are high heat and mass transfer, because of high mixing rates, and particle-to-gas contact. These conditions allow the CFBA's bed of sorbent particles to remove a sorbate from the gas stream with high effectiveness. In a CFBA, material is withdrawn from the bed for treatment (such as desorption) then re-injected into the bed. The SO_2 removal efficiencies for CFBA technologies range from 80 to 98 percent, providing a very effective means of control.

NO_X Emission Controls

Control techniques used to reduce NO_X formation include combustion and post-combustion control measures. Combustion measures consist of operating and equipment modifications that reduce the peak temperature and excess air in the furnace. Post-combustion control involves converting the NO_X in the flue gas to molecular nitrogen and water using either a process that requires a catalyst (selective catalytic reduction) or a process that does not use a catalyst (selective noncatalytic reduction).

Table II-4 presents the 1999 nationwide distribution of NO_X controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Approximately one-third of the boilers do not use additional NO_X controls. The other two-thirds of the units use additional controls to meet the applicable NO_X standards. The predominant control NO_X strategy is to use one or more combustion control techniques. Post-combustion NO_X reduction technologies (both catalytic and noncatalytic) accounted for only a small percentage of the NO_X emission controls used in 1999 (approximately three percent of the total units). However, a number of electric utilities have recently retrofitted are currently actively retrofitting a large number of units with advanced SCR technology to meet the requirements of the federal Title IV acid rain program or the Section 110 Transport SIP call.

Combustion Controls

A variety of combustion control practices can be used including low-NO_X burners (LNBs), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, and burners-out-of-service. Control of NO_X also can be achieved through staged combustion (also called air staging). With staged combustion, the primary combustion zone is fired with most of the air needed for complete combustion of the coal. The remaining air is introduced into the products of the partial combustion in a secondary combustion zone. Air staging lowers the peak flame temperature, thereby reducing thermal NO_X, and lowering the production of fuel NO_X by reducing the oxygen available for combination with the fuel nitrogen. Staged combustion may be achieved through methods that require modifying equipment or operating conditions so that a fuel-rich condition exists near the burners (e.g., using specially designed low- NO_X burners, selectively removing burners from service, or diverting a portion of the combustion air). In cyclone boilers and some other wet bottom designs, combustion occurs with a molten ash layer and the combustion gases flow to the main furnace; this design precludes the use of low NO_X burners and air staging. Low-NO_X burners may be used to lower NO_X emissions by about 25 to 55 percent. Use of overfire air (OFA) as a single NO_X control technique reduces NO_X by 15 to 50 percent. When OFA is combined with low- NO_X burners, reductions of up to 60 percent may result. The actual NO_X reduction achieved with a given combustion control technique may vary from boiler to boiler.

Table II-4 Nationwide distribution of existing NO_X emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

NO_X Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Nationwide Number of Boilers	Nationwide Percentage of Boilers	Percent of Nationwide Electricity Generating Capacity
Combustion controls - low- NO_X burners	CC-LNB	404	35.4 %	43.0 %
Combustion controls - low- NO_X burners + overfire air	CC-LNB/OFA	84	7.4 %	10.4 %
Combustion controls - overfire air	CC-OFA	79	6.9 %	10.6 %
Other combustion controls (a)	CC	83	7.3 %	5.6 %
Selective noncatalytic reduction	SNCR	32	2.8 %	0.6 %
Selective catalytic reduction	SCR	6	0.5 %	1.3 %
No controls reported (b)		452	39.7%	28.5 %
Nationwide Total		1,140 (c)	100 %	100 %

(a) Combustion controls other than low-NO_X burners or overfire air. The controls include burners-out-of service, flue gas recirculation, off-stoichiometric firing, and fluidized-bed combustion.
(b) Entry in ICR response indicated "none," "not applicable," or was left blank.
(c) Does not include the three IGCC units.

Just as the combustion air to the primary combustion zone can be reduced, part of the fuel may be diverted to create a secondary flame with fuel-rich conditions downstream of the primary combustion zone. This combustion technique is termed reburning and involves injecting 10 to 20 percent of the fuel after the primary combustion zone and completing the combustion with overfire air. The fuel injected downstream may not necessarily be the same as that used in the primary combustion zone. In most applications of reburning, the primary fuel is coal and the reburn fuel is natural gas (methane), and the technology is known as "gas reburn."

Other ways to reduce NO_X formation by reducing peak flame temperature include using flue gas recirculation (FGR), reducing boiler load, injecting steam or water into the primary combustion zone, and increasing spacing between burners. By using FGR to return part of the flue gas to the primary combustion zone, the flame temperature and the concentration of oxygen in the primary combustion zone are reduced. Increasing the space between burners provides greater heat transfer to heat-absorbing surfaces. Another combustion control technique involves reducing the boiler load. In this case, the formation of thermal NO_X generally decreases directly with decreases in heat release rate; however, reducing the load may cause poor air and fuel mixing and increase CO and soot emissions.

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH_3) to reduce the NO and NO_2 in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. Typically some ammonia exits the catalyst, on the order of 1-5 ppm in the flue gas; this is called "ammonia slip". The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet, where temperatures range from 230 to 400 °C (450 to 750 °F). The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

SCR catalysts in coal- and oil-fired boilers oxidize a small fraction of the SO_2 in the flue gas to produce SO_3. The SO_3 in the flue gas from an SCR may only be on the order of 10 ppm (depending on the sulfur-content of the fuel), but it can have impacts on the downstream equipment and emissions. The combination of ammonia slip and increased SO_3 can form deposits of ammonium bisulfate in the air preheater. SO can condense in the flue gas in the form of a fine aerosol of sulfuric acid, which can cause a visible plume, the so-called "blue plume".

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO_2 in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific temperature range. Currently, two SNCR processes are commercially available: the THERMAL $DeNO_X$ and the NO_XOUT (USEPA, 1998). The THERMAL $DeNO_X$ uses ammonia gas as the reagent and requires the gas be injected where the flue gas temperature is in the range of 870 to 1090 °C (1,600 to 2,000 °F). Consequently, the ammonia gas is injected at a location upstream of the economizer. However, if the ammonia is injected above 1,090 °C (2,000 °F), the ammonia will oxidize and will result in the formation of excess NO_X emissions. Once the flue gas temperature drops below the optimum temperature range, the effectiveness of the process drops significantly. By adding hydrogen gas or other chemical enhancers, the reduction reactions can be sustained to temperatures down to approximately 700 °C (1,300 °F). The NO_XOUT is a similar process but uses an aqueous urea solution as the reagent in place of ammonia.

Using nitrogen-based reagents requires operators of SNCR systems to closely monitor and control the rate of reagent injection. If injection rates are too high, NO_X emissions may increase, and stack emissions of ammonia in the range of 10 to 50 ppm may also result. A portion (usually around 5 percent) of the NO reduction by SNCR systems results from transformation of NO to N_2O, which is a global warming gas.

Particulate Matter Emission Controls

Four types of control devices are used to collect PM emissions from coal-fired electric utility boilers: electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers. Table II-5 presents the 1999 nationwide distribution of PM controls on coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Electrostatic precipitators are the predominant control type used on coal-fired electric utility boilers both in terms of number of units (84 percent) and total generating capacity (87 percent). The second most common control device type used is a fabric filter. Fabric filters are used on about 14 percent of the coal-fired electric utility boilers. Particle scrubbers are used on approximately three percent of the boilers. The least used control device type is a mechanical collector. Less than one percent of the coal-fired electric utility boilers use this type of control device as the sole PM control. Other boilers equipped with a mechanical collector use this control device in combination with one of the other PM control device types.

Electrostatic Precipitators

Electrostatic precipitator (ESP) control devices have been used to control PM emissions for over 80 years. These devices can be designed to achieve high PM collection efficiencies (greater than 99 percent), but at the cost of increased unit size. An ESP operates by imparting an electrical charge to incoming particles, and then attracting the particles to oppositely charged metal plates for collection. Periodically, the particles collected on the plates are dislodged in sheets or agglomerates (by rapping the plates) and fall into a collection hopper. The dust collected in the ESP hopper is a solid waste that must be disposed of.

Table II-5 Nationwide distribution of existing PM emission controls used for coal-fired electric utility boilers for the year 1999 (USEPA, 2001).

PM Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Electrostatic precipitator (Cold-side)	CS- ESP	822 (a)	72.1 %	74.7 %
Electrostatic precipitator (Hot-side)	HS-ESP	122	10.8 %	11.3 %
Fabric filter	FF	155 (b)	13.6 %	9.4 %
Particle scrubber	PS	23 (c)	2.0%	3.0 %
Mechanical collector (d)	MC	5	0.4 %	0.2 %
Multiple control device combinations (e)		13	1.1 %	1.4 %
Nationwide Total		1,140 (f)	100 %	100 %

(a) Includes 10 boilers with cold-side ESP in combination with upstream mechanical collector.

(b) Includes eight boilers with baghouse in combination with upstream mechanical collector.

(c) Includes two boilers with particle scrubber in combination with upstream mechanical collector.

(d) Boilers using mechanical collector as only PM control device.

(e) Boilers using a combination of two or more different control device types other than mechanical collectors. Includes two boilers that use a hot-side ESP in series with a cold-side ESP.

(f) Does not include the three IGCC units.

The effectiveness of particle capture in an ESP depends largely on the electrical resistance of the particles being collected. An optimum value exists for a given ash. Above and below this value, particles become less effectively charged and collected. Table II-6 presents the PM collection efficiency of an ESP compared with the other control device types. Coal that contains a moderate to high amount of sulfur (more than approximately three percent) produces an easily collected fly ash. Low-sulfur coal produces a high-resistivity fly ash that is more difficult to collect. Resistivity of the fly ash can be changed by operating the boiler at a different temperature or by conditioning the particles upstream of the ESP with sulfur trioxide, sulfuric acid, water, sodium, or ammonia. In addition, collection efficiency is not uniform for all particle sizes. For coal fly ash, particles larger than about 1 to 8 μm and smaller than about 0.3 μm (as opposed to total PM) are typically collected with efficiencies from 95 to 99.9 percent. Particles near the 0.3 μm size are in a poor charging region that reduces collection efficiency to 80 to 95 percent.

An ESP can be used at one of two locations in a coal-fired electric utility boiler system. For many years, every ESP was installed downstream of the air heater where the temperature of the flue gas is between 130 and 180 °C (270 and 350 °F). An ESP installed at this location is referred is as a "cold-side" ESP. However, to meet SO_2 emission requirements, many electric utilities switched to burning low-sulfur coal (discussed in Section 2.3.2 under SO_2 controls). These coals have higher electrical ash resistivities, making the fly ash more difficult to capture downstream of the air heater. Therefore, to take advantage of the lower fly-ash resistivities at higher temperatures, some ESPs are installed upstream of the air heater, where the temperature of the flue gas is in the range of 315 to 400 °C (600 to 750 °F). An ESP installed upstream of the air heater is referred to as a "hot-side" ESP. (Buonicore and Davis, 1992; USEPA, 1998).

Fabric Filters

Fabric filters (FF) have been used for fly ash control from coal-fired electric utility boilers for about 30 years. This type of control device collects fly ash in the combustion gas stream by passing the gases through a porous fabric material. The buildup of solid particles on the fabric surface forms a thin, porous layer of solids or a filter, which further acts as a filtration medium. Gases pass through this cake/fabric filter, but the fly ash is trapped on the cake surface. The fabric material used is typically fabricated in the shape of long, cylindrical bags. Hence, fabric filters also are frequently referred to as "baghouses."

Table II-6 Comparison of PM collection efficiencies for different PM control device types (Buonicore and Davis, 1992).

PM Control Type	Representative PM Mass Collection Efficiency Range	
	Total PM	PM less than 0.3 μm
Electrostatic precipitator (Cold-side)	99 to 99.7 %	80 to 95 %
Electrostatic precipitator (Hot-side)	99 to 99.7 %	80 to 95 %
Fabric filter	99 to 99.9 %	99 to 99.8%
Particle scrubber	95 to 99 %	30 to 85 %
Mechanical collector	70 to 90 %	0 to 15 %

Gas flow through a FF becomes excessively restricted if the filter cake on the bags becomes too thick. Therefore, the dust collected on the bags must be removed periodically. The type of mechanism used to remove the filter cake classifies FF design types. Depending on the FF design type, the dust particles will be collected either on the inside or outside of the bag. For designs in which the dust is collected on the inside of the bags, the dust is removed by either mechanically shaking the bag (called a "shaker type" FF) or by blowing air through the bag from the opposite side (called a "reverse-air" FF). An alternate design mounts the bags over internal frame structures, called "cages" to allow collection of the dust on the outside of the bags. A pulsed jet of compressed air is used to cause a sudden stretching then contraction of the bag fabric dislodging the filter cake from the bag. This design is referred to as a "pulse-jet" FF. The dislodged dust particles fall into a hopper at the bottom of the baghouse. The dust collected in the hopper is a solid waste that must be disposed of.

An FF must be designed and operated carefully to ensure that the bags inside the collector are not damaged or destroyed by adverse operating conditions. The fabric material must be compatible with the gas stream temperatures and chemical composition. Because of the temperature limitations of the available bag fabrics, location of an FF for use in a coal-fired electric utility boiler is restricted to downstream of the air heater. In general, fabric filtration is the best commercially available PM control technology for high-efficiency collection of small particles.

Electrostatic stimulation of fabric filtration (ESFF) involves a modified fabric filter that uses electrostatic charging of incoming dust particles to increase collection efficiency and reduce pressure drop compared to fabric filters without charging. Filter bags are specially made to include wires or conductive threads, which produce an electrical field parallel to the fabric surface. Conductors can also be placed as a single wire in the center of the bag. When the bags are mounted in the baghouse, the conductors are attached to a wiring harness that supplies electricity. As particles enter the field and are charged, they form a porous mass or cake of agglomerates at the fabric surface. Greater porosity of the cake reduces pressure drop, while the agglomeration increases efficiency of small particle collection. Cleaning is required less frequently, resulting in longer bag life. For felted or nonwoven bags, the field promotes collection on the outer surface of the fabric, which also promotes longer bag life. Filtration velocity can be increased so that less fabric area is required in the baghouse. The amount of reduction is based on an economic balance among desired performance, capital cost, and operating costs. A number of variations exist on the ESFF idea of combining particle charging with fabric filtration. (Buonicore and Davis, 1992; Turner and McKenna, 1989).

Particle Scrubbers and Mechanical Collectors

Particle scrubbers are generally much less efficient than ESPs and baghouses (especially in collecting finer fraction of PM). For this reason and because they entail higher operating costs associated with achieving high collection efficiency, they are not widely used in the industry. Similarly, mechanical collectors have the least collection efficiency and are hardly used in the industry. These two methods are not discussed further in this report. (Buonicore and Davis, 1992).

2.3.3. Emission Control Configurations for Coal-fired Electric Utility Boilers

Table II-7 presents the 1999 nationwide distribution of post-combustion control device configurations used for coal-fired electric utility boilers. For approximately 70 percent of the boilers, the only control device used downstream of the furnace is an ESP. If the unit is subject to SO_2 and/or NO_X emission limit standards, these units do burn low-sulfur coals to meet the SO_2 emission limit and use some type of NO_X combustion controls to meet the NO_X emission limit. Approximately 25 percent of the boilers use some combination of post-combustion control devices. The most common configuration used is an ESP with a downstream wet scrubber for SO_2 control. Less than 2 percent of the units used a combination of PM, SO_2, and NO_X post-combustion control devices.

It is important to note that, for the case of PM, the data on PM control as shown for the year 1999 should not have changed in any significant way. However, for SO_2, the requirements of Phase II (starting in the Year 2000) of the Title IV (acid rain provisions) of the 1990 CAAA, should have resulted in some boilers either switching to low -sulfur coal or the application of wet or dry scrubbers. It appears that the SO_2 scrubber retrofit activity in the U.S. has been rather insignificant since 1999. The most active retrofits have involved the application of SCR, SNCR, and gas reburn (in conjunction with low-NO_X burners where appropriate) to significantly reduce NO_X emissions in the eastern U.S. These reductions, however, are only for ozone season (May 1 to September 30) since the NO_X Transport SIP call applies to ozone season. As of 2003, more than 50 applications of SCRs, SNCRs, or gas reburn have either been completed or are under construction.

Table II-7 Nationwide distribution of post-combustion emission control configurations used for coal fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

Post-combustion Control Strategy	Post-Combustion Emission Control Device Configuration									Phase II USEPA ICR Data	
	PM control				SO_2 control			NO_X control			
	ESP	FF	PS	MC	WS	SDA	DI	SCR	SNCR	Number of boilers	Percent of nationwide total number
Post-combustion PM controls only	?									791	69.4%
		?								80	7.0%
	?	?								6	0.5 %
			?							5	0.4 %
	?		?							4	0.4 %
				?						2	0.2 %
	?									2 (a)	0.2 %
Post-combustion PM controls and SO_2 controls	?				?					133	11.7 %
		?				?				38	3.3%
			?		?					18	1.6 %
		?			?					13	1.1 %
	?					?				4	0.4 %
				?	?					3	0.2 %
	?						?			2	0.2 %
	?	?			?					1	0.1 %
Post-combustion PM controls and NO_X controls		?							?	12	1.0 %
	?								?	11	0.9 %
	?							?		1	0.1 %
Post-combustion PM controls, SO_2 controls, and NO_X controls		?				?			?	6	0.5 %
		?				?		?		4	0.4 %
		?			?				?	2	0.2%
	?				?			?		1	0.1 %
	?				?				?	1	0.1 %
Total										1,140 (b)	100 %

(a) Units using hot-side ESP in series with a cold-side ESP. Counted as a "multiple control device combination" in Table II-5

(b) Does not include the three IGCC units.

2.4. Costs and Availability of Technology

The technologies to control three of the precursors of regional haze are commercially available. Since EGUs are the most significant stationary source of SO_2, NO_X, and PM, they have been subject to extensive federal and state regulations to control all three pollutants. The technical feasibility of control technologies has been successfully proven for a large number of small (say, 100 MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, a large amount of cost data have also become available that clearly indicate that many technologies provide substantial and extremely cost effective reductions.

2.4.1. Detailed Capital Costs, Operating and Maintenance Costs, and Cost Effectiveness

Cost of Controlling SO_2 Emissions

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs for NO_X and PM controls. The recent capital costs range from $180/kW for large units (larger than 600 MW) to as high as $350 for small units (200 to 300 MW). However, the last few years has seen a general trend of declining capital costs due to vendor competition and technology maturation. The cost effectiveness (in dollars per ton) is very attractive, since these devices remove a very large amount of SO_2 (driven by high sulfur content of coal burned). The typical cost effectiveness is in the range of 200 to 500 dollars per ton of SO_2 removed though higher values are obtained for small units operating at low capacity factors and burning low-sulfur coal. The cost effectiveness is determined mostly by the baseline pre-controlled SO_2 emisison rate (or sulfur content of fuel), size and capacity factor of the unit, as well as the capital cost of FGDs (that generally ranges from $150 to $200/kW).

Cost of Controlling NO_X

A representative summary of range of costs associated with various technologies for NO_X control is provided below.

Gas Reburn

In general, the capital costs range from $15/kW to $30/kW for gas reburn and $30/kW to $60/kW when using coal as the reburn fuel. Operating costs are mainly driven by fuel cost differential (certainly gas vs. coal). For other fuels (e.g. coal/orimulsion reburning), fuel preparation costs become more important (micronization, atomization) as there is little or no fuel cost differential. The cost in dollars per ton of NO_X removed is in the range of 500 to 2000 dollars.

Retrofit schedules are directly related to the scope of the retrofit requirements. In most cases, 3-6 weeks are adequate for a reburn retrofit.

Low-NO_X Burners

In general, the capital costs for burners range from $10,000 to 50,000 per burner plus installation. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_X. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_X Burners provide moderate NO_X reductions in the range of 30 to 60% at moderate cost ($200 to 500 per ton of NO_X removed).

Overfire Air (OFA)

OFA technologies have little or no impact on operating costs (other than the potential for an increase in unburned carbon - efficiency loss -, and the resulting impact on ash disposal options). Retrofit costs are site-specific. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from $5-$10/kW, with the lower range reflecting easier application whereas the higher costs are typically associated with more difficult and involved retrofits. The cost effectiveness is in the range of $250 to 600 per ton of NO_X removed.

From a schedule standpoint, OFA retrofit projects can require outages of 3 – 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SCR

Capital costs for retrofit SCR systems to coal-fired power generation sources are specific to the individual site, but have been documented to be within the range of $70/kW to about $190/kW. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

Capital costs for retrofit SCR systems on oil and gas-fired boilers are substantially lower (about half to one third) than costs of coal-fired boiler retrofits. Lower volumes of catalyst are required for gas-fired boilers because of the lack of ash and catalysts poisons like arsenic in the flue gas. Capital costs for oil-fired retrofits are intermediate between coal- and gas-fired retrofits. Oil combustion produces some particulate matter, which necessitates larger SCR catalyst volume as compared to that for natural gas.

Operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization), catalyst replacement and dedicated O and M costs. SCR technology offers very high NO_X reductions (from 90 to 95%) and cost effectiveness (in the range of $1,000 to 1500 per ton of NO_X removed).

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_X reductions (25 to 50%). Capital cots range from $10 to $20/kW for power generation boilers.

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_X level and the desired percent reduction. These are typically in the range of \$500-\$700/ton of NO_X.

An additional consideration important in the overall operating costs is the potential contamination of fly ash by ammonia making it potentially unsalable.

Cost of Controlling PM

The costs associated with controlling PM from EGUs generally do not scale on the size of the unit but on the volume of flue gases processed by the control devices (ESPs or fabric filters). The representative costs are provided below.

ESPs

The following values represent typical costs for application of ESPs to units handling a range of flue gas rates (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM):

- Capital: \$15 - \$40/ACFM
- Fixed O&M: Dry ESP's - \$0.25 - \$0.65/yr-ACFM
  Wet ESP's - \$0.15- \$0.50/yr-ACFM
- Variable O&M: Dry ESP's - \$0.45 - \$0.60/yr-ACFM
  Wet ESP's - \$0.25 - \$0.50/yr-ACFM

Fabric Filters

Baghouses have been used extensively for many years in different industries. The EGU sector, while predominantly dominated by ESP's, has started to utilize FF's in the last 20 years.

- Capital: Reverse Air Fabric Filter - \$17 - \$40/ACFM
  Pulse Jet Fabric Filter - \$12 - \$40/ACFM
- Fixed O&M: Reverse Air Fabric Filter - \$0.35 - \$0.75/yr-ACFM
  Pulse Jet Fabric Filter - \$0.50 - \$0.90/yr-ACFM
- Variable O&M: Reverse Air Fabric Filter - \$0.70 - \$0.80/yr-ACFM
  Pulse Jet Fabric Filter - \$.90 - \$1.1/yr-ACFM

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3. INDUSTRIAL BOILERS

Industrial boilers are a significant source of emissions among the twenty-six source categories covered under the Regional Haze Rule. Estimates of national emissions for criteria air pollutants prepared by the USEPA (2000) show that industrial boilers contributed approximately 12 percent of the estimated total national SO_2 emissions and 23 percent of total national NO_X emissions in 1998 (the most recent year for which national estimates are available). Industrial boilers also are one of the largest industrial sources of PM emissions, with 16 percent of the national PM_{10} emissions and 20 percent of the national $PM_{2.5}$ in 1998. Contrast this with the emissions of EGUs for which PM_{10} and $PM_{2.5}$ emissions were 25 percent and 23 percent of national totals in 1998, respectively. In general, the combustion efficiencies achieved by industrial boilers are lower than those of EGUs, resulting in significant emissions of CO (18 percent of the 1998 emissions) and volatile organic compounds (6 percent of the 1998 emissions) from industrial boilers. Industrial boilers also produced 16 percent of the ammonia emissions in 1998. Ammonia is precursor of secondary PM in the atmosphere.

About 46 percent of the SO_2 emissions from industrial boilers are from coal-fired boilers (see Table III-1). The predominant sources of NO_X emissions from industrial boilers are gas-fired boilers (30 percent) and internal combustion boilers (34 percent); coal-fired boilers were only responsible for 17 percent of NO_X emissions from industrial boilers. Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO_2 control and ESPs or baghouses for PM control for oil units).

Table III-1 Distribution of emissions from industrial fuel boilers from 1998 National Emissions Inventory (USEPA, 2000)

Fuel/Source	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Coal	17%	46%	31%	16%
Oil	7%	27%	18%	16%
Gas	39%	21%	18%	26%
Other	4%	5%	25%	32%
Internal Combustion	34%	1%	7%	10%

3.1. Description of Boiler Process

Typically, industrial boilers generate steam used for process heating or on-site generation of electricity. Industrial boilers burn a wider variety of fuels than EGUs and there are a larger number of boiler designs in use than in the electric power sector. According to information contained in USEPA's Docket on "National Emission Standards for Hazardous Air Pollutants for Industrial/ Commercial/Institutional Boilers and Process Heaters" (USEPA, 2004) in 1998 there were 63,767 fossil fuel-fired boilers, 1,100 wood-fired boilers and 998 boilers classified as non-fossil-fuel-fired. The fossil fuels fired were natural gas, distillate oil, residual oil, coal and petroleum coke. The majority (75 to 95 percent) of the boilers firing natural gas, residual oil and distillate oil are fire tube boilers; the rest are water tube boilers. Coal-fired boilers include fluidized bed boilers, stokers, cyclone boilers, and pulverized coal-fired boilers (wall-fired or tangentially fired). Wood-fired boilers include fluidized bed boilers, cyclones, stokers and dutch ovens.

3.2. Review of BART-Eligible Industrial Boilers in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities.[5]

Table III-2 BART-Eligible Facilities in the Industrial Boiler Category

State	Company/Facility	City/Town	Category
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY-KNEELAND STATION	Boston	boilers
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	Katadhin - Mill W.	Millinocket	boilers
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Dartmouth College	Hanover	boilers
Rhode Island	BROWN UNIVERSITY	Providence	boilers

3.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for sulfur dioxide (SO_2), nitrogen oxides (NO_X), and primary PM emissions, the three major precursors of observed regional haze in the atmosphere. SO_2 and NO_X are mostly converted to ammonium sulfate and ammonium nitrate that are formed by the reactions of precursor gases with ammonia, which is emitted mostly from agricultural and cattle-related activities.

Pollutant emission controls are generally divided into three major types:

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[5] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

- *Pre-combustion Controls.* Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls.* Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

3.3.1. Emission Characteristics of Regional Haze Precursors from Industrial Boilers

Nitrogen Oxides

The formation of NO_X is an unfortunate byproduct of the combustion of fossil fuels. Both NO and NO_2 (collectively called NO_X) are formed during fossil fuel combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the fuel. The degree to which this conversion occurs is dependent on many factors including both the combustion process itself and the properties of the particular fuel being burned. This explains why similar boilers firing different fuels or similar fuels burned in different boilers will yield different NO_X emissions. Overall, total NO_X formed during combustion is composed predominantly of NO mixed with small quantities of NO_2 (typically less than 10 percent of the total NO_X formed). However, once NO formed during coal combustion is emitted to the atmosphere, the NO is oxidized to NO_2.

The NO_X formed during combustion by oxidation of molecular nitrogen (N_2) in the combustion air is referred to as "thermal NO_X." The oxidation reactions converting N_2 to NO and NO_2 become very rapid once gas temperatures rise above 1,700°C (3,100°F). Formation of thermal NO_X in a boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above 1,700 °C, the gas residence time at these temperatures, or the quantity of excess combustion air affects thermal NO_X formation. The formation of NO_X by oxidation of nitrogen compounds contained in the coal is referred to as "fuel NO_X." The nitrogen content in coal and petcoke ranges from approximately 0.5 to 2 percent; in wood, the nitrogen content is typically 0.1 to 0.2 percent. The amount of nitrogen available in the fuel is relatively small compared with the amount of nitrogen available in the combustion air. However, a significant portion of the fuel nitrogen can be converted to NO in the flame. Local temperature, oxygen concentration and NO concentration affect the conversion of fuel nitrogen to NO and this is exploited in low-NO_X firing systems.

Sulfur Dioxide

SO_2, like NO_X, is a precursor to acid rain and fine particulate matter ($PM_{2.5}$) and is also an undesirable byproduct of the combustion of sulfur-containing fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8 percent or more. Natural gas contains virtually no sulfur. Residual oil can have 1 to 2 percent sulfur by weight, while petroleum coke can have as much as 6 percent sulfur. During combustion, sulfur compounds in the fuel are oxidized to gaseous SO_2 or SO_3. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, 98 percent). The more alkaline nature of ash in some sub bituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. When firing petcoke or residual oil, more of the SO_2 is converted to SO_3 because of the oxidation that is catalyzed by vanadium in the ash. In coal-fired boilers, SO_3 levels are typically 10 ppm or less. With petcoke firing, however, SO_3 levels as high as several hundred ppm have been reported (Fernando,2001). Formation of SO_3 is a concern because the temperature of the particulate control device or scrubber is often below the acid dew point, resulting in nucleation and condensation of ultrafine sulfuric acid particles from the SO_3 present in the gas. These particles can contribute to the fine PM emissions from the stack.

Unlike nitrogen in fossil fuels and wood, almost all of the sulfur in fuel is oxidized to form SO_2. This means that the relationship between sulfur content in the fuel and SO_2 production is much more direct than that between fuel nitrogen and NO_X, and as such, it makes fuel switching (for example higher to lower sulfur coal) directly proportional to reductions in SO_2. Generally, the percentage of sulfur in the fuel that is converted to sulfur oxides during combustion does not vary with the boiler design or operation. The exception to this is the fluidized bed boiler in which limestone is added to the bed. The bed is operated at a sufficiently low temperature (compared to other combustion systems) that sulfur is captured effectively in the bed as calcium sulfate.

Particulate Matter

Primary PM emissions from boilers consist primarily of fly ash. Ash is the unburned carbon and the mineral portion of the fuel. Coals contain 4 to 12 percent ash typically. Other liquid or solid fuels (oil, petroleum coke, wood) contain less than one percent ash. The amount of ash that ultimately exits the boiler unit as fly ash is a complex function of the fuel properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone-fired boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs promote ash vaporization and this results in larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from boilers result from reactions of the SO_2 and NO_X compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO_2 and NO_X compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO_3), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned fuel) contained in the fly ash. Combustion efficiencies tend to be lower in industrial boilers than in EGUs. Oil or petcoke combustion results in high amounts of sulfur trioxide as compared to coal combustion because of the high vanadium content of residual oil and petcoke.

NO_X control technologies that inject ammonia or amine-based reagents (like Selective Catalytic Reduction or Selective Non-Catalytic Reduction) produce ammonia, generally with concentrations less than 10 ppm. This ammonia can also form fine particulate in the stack, if it persists through the air pollution control devices.

3.3.2. Control Technologies used for Industrial Boilers

Application Status

According to the 1998 survey of industrial boilers by USEPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had any kind of air pollution control device. More coal-fired boilers had air pollution control devices: 47 percent had some control device and these were largely PM controls.

For PM controls, ESPs were used on 12 percent of the coal-fired boiler units in 1998, fabric filters or baghouses were used on 10 percent of the boiler units, mechanical collectors were used on 21 percent of the units, and particulate scrubbers were only used on 2 percent of the units. 66 percent of wood-fired boilers used mechanical collectors for PM control, while 10 percent used PM scrubbers and another 10 percent used ESPs.

Post-combustion SO_2 control was used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petcoke: 2 percent of boilers firing petroleum coke had acid scrubbers. A small percentage of industrial boilers had combustion controls in place in 1998, although since 1998, additional low-NO_X firing systems may have been installed.

SO_2 Reduction Overview

Almost all SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. The exception to the nearly universal use of post-combustion controls is found in fluidized bed boilers, in which limestone is added to the fluidized bed combustion. Typically 90 percent of the sulfur can be captured in a coal-fired fluidized bed using limestone with Ca/S molar ratios of 2 to 2.5, depending on the sulfur content of the fuel, the reactivity of the limestone and the operation of the combustor.

Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and/or "Scrubbers" and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability, performance and cost.

Pre-Combustion Control

A coal with sufficiently low sulfur content that when burned in the boiler meets the applicable SO_2 emission standards without the use of additional controls is sometimes referred to as "compliance coal." Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

In-Process Controls

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800 to 870°C (1500 to 1600°F). The lower temperatures allow the use of limestone or dolomite to be added to the bed to capture sulfur. Limestone ($CaCO_3$) is converted to CaO at approximately 800°C (1500°F). SO_2 released from the fuel reacts with CaO to form $CaSO_4$, which is thermodynamically stable at bed temperatures. By recycling some of the solids leaving the bed, which contain unsulfated calcium, 90 percent removal of SO_2 can be achieved with Ca/S molar ratios of 2 to 2.5 in circulating fluidized beds. Higher Ca/S ratios are required in bubbling beds. In either case, the sorbent is removed with the ash from the bed and sent to disposal.

Post-Combustion Controls

Wet Processes

Wet FGD "scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s. They represent the predominant SO_2 control technology in use today with over 80% of the controlled capacity in the world and the U.S.

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90 percent SO_2 capture. Currently, advanced scrubber designs have eliminated many of the early problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with some units providing over 95 percent control.

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate and even seawater-based processes are commercial. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, efficiency targets, etc.

Dry Processes

Dry processes include spray dryer absorbers (SDA) and Dry Sorbent Injection (DSI) technologies. SDA refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber hence the common reference to "dry scrubber"; conversely, DSI uses the existing boiler/duct system as the "reactor" and several configurations are possible based on the temperature window desired. This can occur at furnace (~2200°F), economizer (800-900°F) or duct temperatures (~250°F). Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (e.g., atomization). Therefore, high-sulfur applications are not likely. In addition, another common feature among them is the need for particulate control downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (baghouses) which are, not only efficient collectors of particulates, but also provide additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the filters.

Dry SO_2 controls vary significantly in performance, with SDAs being able to achieve about 80 percent removal rates, whereas the various forms of DSI are capable of 40 to 75 percent efficiencies.

NO_X Reduction Overview

As a result of the complex interactions in the formation of NO_X, an equally large number of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NO_X emission control is to divide them into two major categories: (1) those that minimize the formation of NO_X during the combustion process (e.g., smaller quantities of NO_X are formed); and (2) those that reduce the amount of NO_X formed during combustion prior to exiting the stack into the atmosphere. In industry "language" it is common to refer to the first approach under the "umbrella" of *Combustion Modifications* whereas technologies in the second category are termed Post-*Combustion Controls*.

Within each of these categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible but often desirable as they may produce more effective NO_X control than the application of a stand-alone technology.

The following summaries describe the major technologies in each category.

Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts (similar to a "tune-up" in a car) to the deployment of dedicated technologies such as Low-NO_X Burners (LNB), Overfire Air (OFA) or gas recirculation (GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to improvements in NO_X emissions of 5 to 15 percent or even higher in cases where a unit may be badly "de-tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit (just as the improvement in a car from a "tune-up" depends on how "bad" it was running prior to it), and as such have limited opportunity for drastic emission reductions.

Recent development of "intelligent controls" - software-based systems that "learn" to operate a unit and then maintain its performance during normal operation, are expected help in keeping plants well-tuned, as they gain acceptance and become common features in combustion control systems.

Low-NO_X Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NO_X during combustion. Simply, this is accomplished by "controlling" the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging").

These technologies are the most prevalent in the power industry at present. For example, plants that have had to comply with Title IV of the CAAA of 1992 have largely used these technologies for compliance. Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NO_X reductions of 40 to 60 percent from uncontrolled levels. Again, the type of boiler (e.g., dry versus wet-bottom, wall- versus tangential-fired, NSPS versus pre-NSPS) and the type of fuel (e.g., bituminous versus sub-bituminous) will influence the actual performance achieved.

Furthermore, all combustion modification approaches face a common challenge: that of "striking a balance" between NO_X reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower efficiency (more fuel needed for the same electrical output), but also the contamination of the fly ash itself possibly making it unsuitable for reutilization (e.g., cement industry).

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss).

From a schedule standpoint, LNB/OFA retrofit projects have "lead" times of 10 to 14 weeks and can require outages of 6 to 10 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Post-Combustion Controls

Readily available post-combustion NO_X controls are limited to Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_X produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700°F-2000°F) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_X.

While this difference between the two technologies may seem minor, it yields significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "makeshift" reactor which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_X); and finally, has limited NO_X reduction capability (typically 30 to 40 percent with some cases achieving reductions in the 50 percent range). SCR, on the other hand, offers lower operating costs and the opportunity for very high NO_X reductions (up to 90 percent and higher).

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR and ammonia for SCR, - which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NO_X level and the desired percent reduction. Two additional parameters important in the overall operating costs are: (1) the potential contamination of coal fly ash by ammonia making it unsaleable; and (2) the life cycle of the catalyst due to premature "poisoning."

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH3) to reduce the NO and NO_2 in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet. The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO_2 in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific temperature range. A minimum of 0.5 seconds of residence time is required at a temperature of about $1800^{o}F$ to achieve high (50 to 60 percent) NO_X removal with SNCR. Good dispersion of the reagent in the flue gas is also needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.

PM Reduction Overview

Particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. In combustion processes, the mineral matter (inorganic impurities) is converted to ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", " PM_{10}", " $PM_{2.5}$" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Quantity and characteristics of the fly ash and particle size distribution depend on the mineral matter content of the fuel, combustion system, and operating conditions. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverized coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom furnaces. In dry bottom boilers, 10 to 20 percent of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50 to 60 percent of the ash is discharged at the bottom of the boiler as slag. Stokers or grate-fired boilers are used to burn coal, wood and waste. The majority of the ash falls through the grate and is discharged as bottom ash. Mineral composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash.

PM emissions from other point source processes involve similar phenomena where particulate matter is carried with the flue gas, in suspension to the stack. Hence, the general technologies applicable to one source are typically suitable for the others as well. Factors such as type and quantity of PM, characteristics of the process gas (temperature, moisture, other contaminants) have a major influence on the selection and design of the PM control technology.

PM Control Technologies

The following four major types of particulate controls technologies are common for a variety of applications:

Wet scrubbers

Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the "venturi scrubber" is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. Venturi scrubbers are effective devices for particulate control. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressures are required. High-energy scrubbers refer to designs operating at pressure losses of 50 to 70 inches of water. Of course, higher pressure translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis.

Electrostatic Precipitators (ESP)

ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charged plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates. In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron on a mass basis.

Fabric Filters

These are essentially "giant" vacuum cleaners. As in the case of the dry ESP, Fabric Filters (FFs, sometimes called baghouses) are not well suited for wet gas applications. However FFs are extremely efficient in collecting PM including fine (submicron) size fractions.

Cyclones

Cyclones are devices that separate particulates from the gas stream through aerodynamic/centrifugal forces. However, the technology is only effective in removing larger size particles (greater than about five microns).

3.4. Costs of Technology

3.4.1. NO_X Technologies

A representative summary of range of costs associated with various technologies for NO_X control in industrial boilers is provided in Table III-4, taken from Reference 4. Capital costs and pollutant removal costs (in $/ton of pollutant removed) are given for three different boiler sizes: 1000, 500, and 100 MMBtu/hr. For each boiler size, the range of costs corresponds to a range of capacities from about low (5 to 14 percent of capacity) to high (86 to 93 percent of capacity). Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities.

Low-NO_X Burners (LNBs)

The capital costs for coal burners range from $2,500 to $5,100 per MMBtu/hr of boiler size. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_X. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_X Burners provide moderate NO_X reductions in the range of 30 to 50 percent at moderate to high cost ($200 to $3,000 per ton of NO_X removed). The size of the boiler affects both the capital cost and the cost per ton. The combination of LNBs and overfire air (OFA), with or without flue gas recirculation (FGR), is more expensive but NO_X reduction is higher, as high as 80 percent for gas-fired boilers. From a schedule standpoint, LBB/OFA retrofit projects can require outages of 3 to 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_X reductions (about 40 percent). As discussed above, the NO_X reduction that can be achieved will vary from one boiler to another, and depend on the residence time available in the boiler in which the temperatures fall within the window for the SNCR chemistry to take place. Capital costs range from \$2,000 to \$4,000 per MMBtu/hr for industrial boilers. Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_X level and the desired percent reduction. These are typically in the range of \$1,300 to \$10,000/ton of NO_X.

An additional consideration important in the overall operating costs for coal-fired boilers is the potential contamination of fly ash by ammonia, making it potentially unsalable.

SCR

Capital costs for retrofit SCR systems to industrial boilers are mostly within the range of \$4,000 to \$15,000 per MMBtu/hr. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers. Coal-fired boilers have higher capital costs. The systems must be larger to allow for flow of fly ash through the catalyst without plugging. Catalyst activity deteriorates faster in coal-fired boilers because of the higher levels of contaminants in the flue gas (like arsenic) and the deposition of ash on the catalyst. Catalysts must be replaced more frequently in coal-fired systems, which increases the operating cost. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

In addition to catalyst replacement costs, operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization) and dedicated O and M costs. SCR technology offers very high NO_X reductions (80 percent or better); the cost per ton of NO_X removed is considerably higher than SNCR, although the overall NO_X reduction is higher.

3.4.2. SO_2 Technologies

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs for NO_X and PM controls (Khan, 2004b). Dry sorbent injection (DSI) has lower capital costs than a spray dryer absorber (SDA), although DSI can only achieve about 40 percent SO_2 reduction. SDA systems can achieve 90 percent reduction. Capital costs for DSI are in the range of $8,600 to $26,000 per MMBtu/hr, depending on the size of the system and on the sulfur content of the fuel. Capital costs for SDA systems are about double that for DSI systems, but the cost per ton of SO_2 removed is similar: $400 to $4,000 per ton of SO_2 removed. These costs are higher than the costs for scrubbers on EGUs, which are only $100 to $200 per ton of SO_2 removed.

Wet FGD systems also remove 90 percent and higher of the SO_2, but the capital cost is about 50% higher than the cost for an SDA system. The costs per ton of SO_2 removed are similar to the costs for SDA for coal-fired boilers. Costs per ton of SO_2 are estimated to be about twice as high for oil-fired boilers as compared to coal-fired boilers.

3.4.3. PM Technologies

As with most control technologies, the costs of PM controls involve both capital and operating costs. A cost-effectiveness indicator, such as $/ton as is typically used for other technologies (e.g. NO_X and SO_2), is very difficult to address for generic PM control costs, as the range of PM reductions for different fuels and processes is so wide that cost ranges become useless. An attempt to summarize costs in terms of capital and O&M components is presented below.

Capital

While it is customary to indicate capital costs on a $/kW basis for power generation applications, this is not relevant for non-power applications since no electricity is generated. However, one of the main parameters dictating the "sizing" and hence, the costs of a PM control device, is the quantity of flue gas it must handle. As a result, it is more appropriate to generalize capital costs per actual cubic feet per minute (ACFM) of gas flow and is given on a "$/ACFM" basis. The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Dry ESPs - $15 - $40/ACFM
- Wet ESPs - $15 - $40/ACFM
- Reverse Air Fabric Filter - $17 - $40/ACFM
- Pulse Jet Fabric Filter - $12 - $40/ACFM
- Venturi Scrubber - $5 - $20/ACFM
- Cyclone - $1 - $5/ACFM

O&M

O&M costs are difficult to generalize for such a variety of technologies and applications, as they are affected by many parameters that include type of fuel, type of process, local ash disposal options, local cost of power, etc. O&M costs include fixed costs (FOM) and variable costs (VOM). The costs provided below are presented in $/year-ACFM and reflect costs for coal-based fuels but should reasonably apply to other sources as well.

Fixed O&M

- Dry ESPs - $0.25 - $0.65/yr-ACFM
- Wet ESPs - $0.15- $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM
- Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM
- Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Cyclone – Not applicable

Variable O&M

- Dry ESPs - $0.45 - $0.60/yr-ACFM
- Wet ESPs - $0.25 - $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM
- Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM
- Venturi Scrubber - $1.2 - $1.8/yr-ACFM
- Cyclone – Not applicable

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Table III-4. NO_X reduction and control costs for industrial boilers (Khan, 2004a).

Fuel	**Technology**	**NO_X Reduction**	**$/Ton of Pollutant vs. Boiler Size**			**Capital Costs $/ MMBtu/hr vs. Boiler Size**		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Gas	LNB/OFA	60	280 - 5260	424 - 7973	559 - 10521	1280	1940	2554
Gas	LNB/OFA/GR	80	368 - 6204	543 - 9415	700 - 12374	2000	3031	3991
Oil	LNB/OFA(1)	30	306 - 2630	464 - 3986	612 - 5260	1280	1940	2554
Oil	LNB/OFA/GR (1)	50	326 - 2505	477 - 3790	615 - 4973	2000	3031	3991
Oil	LNB/OFA/GR (2)	30	741 - 5694	1085 - 8613	1399 - 11303	2000	3031	3991
Coal	LNB (subbit.)	51	256 - 1520	389 - 2305	512 - 3033	2554	3872	5097
Coal	LNB/OFA (subbit.)	65	306 - 1727	454 - 2608	593 - 3428	3649	5531	7281
Coal	LNB/OFA (bit)	51	392 - 2197	581 - 3317	757 - 4358	3649	5531	7281
Gas	SNCR	40	1842 - 14165	2193 - 20870	2521 - 27105	2111	3200	4212
Oil	SNCR (1)	40	1485 - 4271	1670 - 5892	1840 - 7399	2045	3100	4081
Oil	SNCR (2)	40	1628 - 5497	1889 - 7753	2123 - 9842	2045	3100	4081
Coal	SNCR	40	1285 - 2962	1473 - 4015	1625 - 4970	2639	4000	5266
Gas	SCR	80	986 - 14815	1354 - 21095	1689 - 26859	4014	6084	8009
Oil	SCR (1)	80	760 - 10458	997 - 14443	1245 - 18544	5547	8407	11067
Oil	SCR (2)	80	1017 - 14601	1343 - 20113	1694 - 25838	5547	8407	11067
Coal	SCR	80	876 - 4481	1123 - 5924	1349 - 7262	7298	11062	14562

Notes

(1) 0.5 lb/MMBtu inlet NO_X

(2) 0.36 lb/MMBtu inlet NO_X

Table III-5. SO_2 reduction and control costs for industrial boilers (Khan, 2004b).

Fuel	**Technology**	**SO_2 Reduction**	**$/Ton of Pollutant vs. Boiler Size**			**Capital Costs $/ MMBtu/hr vs. Boiler Size**		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Coal	DSI high S coal	40	633 - 1703	763 - 2471	943 - 3543	12508	18838	26835
Coal	DSI lower S coal	40	697 - 1986	849 - 2952	1075 - 4283	8648	12987	17995
Coal	SDA	90	381 - 1500	569 - 2611	790 - 3920	20275	36226	54679
Coal	Wet FGD high S coal	90	373 - 1789	528 - 2708	664 - 3513	32313	48857	64240
Coal	Wet FGD lower S coal	90	461 - 2273	661 - 3460	836 - 4495	29888	45283	59598
Oil	Wet FGD	90	693 - 5082	1011 - 7801	1285 - 10160	27455	41604	54761

4. PORTLAND CEMENT KILNS

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 2,650°F. High combustion temperatures require significant amounts of fuel and can result in significant emissions of NO_X and SO_2. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

The cement industry has seen significant growth in capacity and technology over the last 30 years. In 2000, the U.S. had 201 cement kilns with the annual capacity to produce 84 million metrics tons of concrete, with production projected to grow to 109 million metric tons in 2004 (Portland Cement Association, 2000).

4.1. Description of Cement-Making Processes

Concrete is a combination of Portland cement, sand, and gravel. The key component of Portland cement is clinker, a material produced by heating limestone and other raw materials to temperatures over 2,650°F, requiring combustion temperatures of about 3,000°F. These high temperatures are normally achieved in a rotary kiln, as shown in Figure IV-1. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

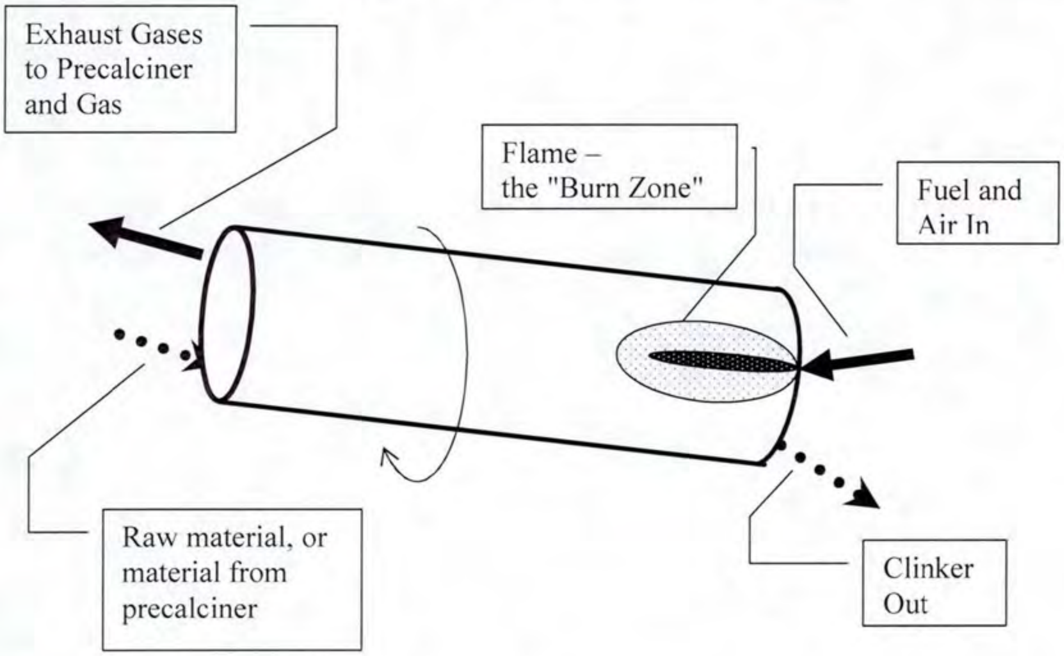

Figure IV-1. Simplified Sketch of a Rotary Kiln.

Cement kilns fall into four general process categories. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500°F to 1,650°F. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. In long kiln systems, the raw feed material is added to the rotary kiln itself as either a powder ("dry") or a slurry ("wet"). Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and typically have greater capacity. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Preheaters could also be replaced with suspension preheaters, but these are less common. If past trends continue, many of the existing long wet kilns and dry kilns are expected to be replaced with precalciner and preheater kilns since precalciner and preheater kilns are more energy efficient and also typically have greater capacity.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. The current fuel use in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NO_X for nearly all cement applications (see the section on NO_X controls included later).

Recent years have seen Portland cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility's outputs or reduce their operating costs. Incidentally, some of these technologies also offer the potential to reduce NO_X and other emissions.

4.2. Review of BART-Eligible Cement Kilns in the MANE-VU Region

NESCAUM's analysis of BART-eligible sources in the MANE-VU Region[6] (NESCAUM, 2004) identified two Portland cement facilities as being eligible for BART. The facilities are shown in Table IV-1. *[Editor's note: Additional facilities are likely to be added when PA and NY inventories are complete]*

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[6] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

Table IV-1 BART-Eligible Portland Cement facilities in MANE-VU Region

Facility	Kiln type	Capacity, thousands tons/yr	Primary Fuel(s)
St. Lawrence Cement (Hagerstown, MD)	Dry	550	Coal
Dragon Products (Thomaston, ME)	Wet	392	Coal, petcoke

4.3. Available Control Technologies

A number of technologies exist for controlling emissions from cement kilns. Secondary (post-combustion) control devices can be helpful in reducing emissions, and a variety of these are available. Many technologies and techniques have been developed in response to a specific environmental need and target a specific pollutant, sometimes achieving reduction in other pollutants at the same time. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the targeted pollutant. Controls are examined for SO_2, NO_X, PM, and VOCs.

4.3.1. SO_2 Controls

In contrast with electric utility boilers, SO_2 emissions from rotary kilns producing cement clinker under oxidizing conditions are nearly independent of fuel sulfur input, but, rather, are closely related to the amount of sulfide (e.g. pyrite) in kiln feed and to the molar ratio of total sulfur to total alkali input to the system. In cement kilns SO_2 emissions generally depend on:

- Inherent SO_2 removal efficiency of kiln system,
- Form of sulfur (e.g. pyritic) and sulfur concentrations in raw material,
- Molecular ratio between sulfur and alkalis,
- Prevailing conditions (oxidizing or reducing) and their location within kiln, and
- Temperature profile in the kiln system.

Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit of reducing SO_2 levels.

In addition to the control techniques used in the electric utility boilers, cement plants may also resort to other basic reductions techniques involving reduction of sulfur input to the kiln, by switching fuels or changing the limestone, or reduction of SO_2 emissions from reducing both the sulfur in the sources and using a secondary control device. It is common to achieve some level of SO_2 reductions when seeking to reduce another pollutant, usually NO_X (technologies targeting another pollutant, but also reducing SO_2, are described in the NO_X and PM sections below). In addition to considering a change in the primary fuel for the kiln, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO_2. Including high-pressure air injection at a mid-kiln firing site can limit oxygen in the kiln and suppress SO_2 formation (Hansen, 2002). Since these techniques are primarily used to reduce NO_X, more information about mid-kiln fuel injection can be found in the section on NO_X emissions, but other specific SO_2 control technologies applicable to cement kilns are listed below.

Fuel Switching

Selecting a fuel with lower sulfur content, a strategy commonly adopted in the utility boilers, is less effective in cement-making systems, where SO_2 emissions are not strongly dependent on fuel sulfur content. Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit in SO_2 levels.

Inherent Removal

Raw materials, primarily limestone, are preheated in the cement-making process either in the preheater tower or in the rotary kiln. In either case, the limestone comes in contact with hot combustion exhaust gases. The calcium in the lime reacts with SO_2 in the gas, providing in-process removal of sulfur in the kiln system. Removal efficiencies in rotary kiln systems range between 38% and 99% of sulfur input, and 50% to 70% of the remaining SO_2 is removed from exhaust gases when passing through an in-line raw mill system (Miller et al., 2001).

Process Alterations

The following methods to remove and prevent formation of SO_2 by modifying or controlling conditions in the system are available due to the nature of the Portland cement manufacturing process:

- The oxygen concentration of the exhaust gases can be controlled to ensure sufficient oxygen exists to stabilize alkali and calcium sulfate compounds formed in the process. Concentrations of O_2 and, more importantly CO, have a strong influence on the stability of alkali and calcium sulfates in the burning zone. Control of burning- zone O_2 and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary kilns producing cement clinker. The downside of this technique is the more favorable conditions created for generation of NO_X in the rotary kiln.
- Burning-zone flame shape can be modified to minimize localized reducing conditions. It has been observed (Hansen, 1986) that flame impingement in the hot zone had a major effect on SO_2 emissions from the kiln, even if total oxygen is sufficient to fully combust all fuel. Avoiding flame impingement in the burning zone minimizes SO_2 formation. Avoiding flame impingement on the clinker, a technique applicable to all rotary

kilns producing cement clinker, requires proper solid fuel preparation and proper flame shaping and control.

- Raw materials can be altered to affect the alkali/sulfur molar ratio. SO_2 concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur; when alkalis are in excess of sulfur, SO_2 emissions are typically low, due to more sulfur being retained in clinker as alkali sulfates. Also, kiln feed containing carbon seems to directly cause SO_2 emissions. Changing raw materials may reduce SO_2 emissions. Substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds reduces SO_2 emissions. Replacement of raw materials, however, is often constrained by economic considerations, while alkali input increase may also be limited by cement product quality specifications on total alkali in cement.
- Alterations to system can influence SO_2 emissions. It has been found that an improved distribution of kiln feed may equalize temperatures in bottom stage cyclones and reduce SO_2 emission by as much as 20% (Miller, 2001).

Scrubbers

Dry Reagent Injection

Steuch and Johansen (1991) found that Ca $(OH)_2$ (hydrated lime) was the most effective scrubbing agent, particularly when added to the kiln feed and when the exhaust gases were near the dew point. Adding quicklime or hydrated lime into the upper preheater cyclones demonstrated up to 70% removal efficiency (Nielse, 1991).

Several dry reagent systems are available:

- The RMC Pacific process (Sheth, 1991) injects dry $Ca(OH)_2$, and with different stoichiometric ratios (40:1 to 50:1), has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.
- Krupp Polysius Polydesox process uses hydrated lime where SO_2 in the raw feed tends to form from pyrites and obtains removal efficiencies of up to 85% (Miller, 2001).
- De-SoX Cyclone, by Fuller Company (Miller, 2001), reduces SO_2 emissions in a precalciner kiln by removing a portion of the gases from the precalciner outlet to a cyclone, and from there to the Stage II cyclone where pyritic sulfur in kiln feed is decomposed into SO_2. The feed (or "raw meal"), containing freshly produced lime, is discharged into the outlet duct of the second stage (this process is known as hot meal injection)._Removal efficiencies of 5 to 30% are claimed.

Lime/Limestone Spray Dryer Absorber

Design stoichiometric ratios of calcium to sulfur for spray dryer systems in utility boilers are typically between 0.9 and 1.5, with most below 1.0. These SO_2 scrubbers are designed for removal efficiencies in excess of 80%.

SO_2 reacts with $CaCO_3$, to form $CaSO_4$, a reaction that becomes more complete as the temperature and the fineness of $CaCO_3$ increase. The presence of water vapor also increases conversion.

Most of the spray dryer type SO_2 control technologies in the cement industry are applied to preheater or preheater/precalciner kilns. Exhaust gases from long dry kilns are cooled by either spray water introduced into the feed end of the kiln or by dilution air-cooling after the gases leave the kiln. Adding a conditioning tower to replace water sprays or dilution air enables the alkaline slurry system to be used to reduce SO_2 emissions (the equivalent of a spray dryer). The range of temperatures for exit gases from long wet kilns does not allow the use of an alkaline slurry spray dryer type scrubber because the addition of the lime slurry may drop the exhaust gases temperature below the acid dew point, creating significant plugging and corrosion problems in the downstream Particulate Control Device (PCD), duct work, and induced draft (ID) fan.

RMC Pacific's Alkaline Slurry Injection System (Sheth, 1991)

RMC Pacific uses a hydrated lime, spray dryer absorber to reduce SO_2 emissions. The captured sulfur compounds are returned as a portion of the raw material feedstock to the roller mill, which results in no scrubber effluent or sludge disposal. When SO_2 emissions are high and preheater exit gas temperatures are low, sufficient lime slurry cannot be added to reduce SO_2 to acceptable levels. With different stoichiometric ratios (40:1 to 50:1), the process has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.

EnviroCare Microfine Lime System (Miller, 2001)

This system uses the existing gas conditioning tower to introduce the scrubbing reagent (water suspension of finely pulverized calcium hydroxide, $Ca\ (OH)_2$). The small size of the lime particles (3-10 microns) allows the particles to dissolve in water droplets quickly and react with SO_2 as it is absorbed into the water droplet. The dried lime continues to react with any remaining SO_2 in the downstream kiln system and PCD. Lime injection rate can be optimized through a feedback control loop from an SO_2 monitor. EnviroCare claims an SO_2 removal efficiency of greater than 90%.

Wet SO_2 Scrubbers

Wet scrubbers have been used successfully in the utility industry. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control applied to the exhaust gas from a cement kiln can be avoided if these systems are installed downstream of a high efficiency PCD (e.g., fabric filter). Failure of the PCD can pose difficult problems for a downstream wet scrubber.

Fuller Company (FLS Miljø) (Miller, 2001)

The Monsanto Dyna Wave wet SO_2 scrubber has been installed by the Fuller Company and used on several cement kilns in the U.S. This wet scrubber is designed to remove SO_2, halide gases, and some particulate matter.

The scrubber, typically located downstream from the kiln PCD and operated under positive pressure, uses limestone as the absorbent. A slurry (approximately 20% limestone and 80% water) produced in the mixing tank is sprayed countercurrent to the gas flow to cool the gases and react with SO_2 forming calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$), which precipitates. Air is sparged into the sump at the bottom of the tower to oxidize $CaSO_3$ to $CaSO_4+2H_2O$ (gypsum).

Monsanto EnviroChem DynaWave (Miller, 2001)

DynaWave is a "Reverse Jet" scrubber that can simultaneously accomplish several gas cleaning/process needs: hot gas quenching, particulate removal, and acid gas absorption. The reverse jet is an annular orifice scrubber having one to three large-bore nozzles through which a relatively large volume of scrubbing liquid is injected counter to the gas flow to create a froth zone. The gas collides with the liquid, forcing the liquid radialy outward toward the wall. A standing wave, created at the point the liquid is reversed by the gas, is an extremely turbulent region where the gas absorption and particulate collection occurs.

The system is a tailpipe system generally installed downstream of the PCD, and operates with a saturated gas stream. Therefore, it would likely be applicable to most if not all the cement kilns. A single-stage DynaWave scrubber in full-scale operation has a reported SO_2 removal efficiency of about 90%. Monsanto EnviroChem claims that multiple units may be installed in series to achieve whatever removal efficiency is required (e.g., 99.9%).

4.3.2. NO_X Controls

The following sections discuss the formation of NO_X in cement kilns, potential NO_X control techniques, NO_X control in the cement industry, and the cost effectiveness of applicable controls.

NO_X Formation in Kiln Systems

Nitrogen oxides (NO_X) are formed during the combustion of fuels in the cement-making process. In kiln exhaust gases, more than 90% of NO_X is NO, with NO_2 generally making up the remainder from rotary kilns producing cement clinkers (Gardeik, 1984). There are three different NO_X formation mechanisms - thermal, fuel, and feed NO_X - typically contributing to NO_X emissions.

Thermal NO_X

Thermal NO_X is formed by oxidation of atmospheric molecular nitrogen at high temperatures (>1,200 °C). Most NO_X formed in the high-temperature environment of the main combustion zone (burning zone) of a kiln is "thermal NO_X". Since the flame temperature in a kiln is significantly above that threshold, a considerable amount of thermal NO is generated in the burning zone.

While conditions in the burning zone of a cement kiln favor formation of thermal NO_X, those prevalent in secondary combustion zones (e.g. calciners, preheater riser ducts and mid-kiln firing in long wet or dry kilns) with temperatures below 1200°C, are less conducive to significant thermal NO_X formation. In that zone, formation of fuel NO_X and feed NOx is more prevalent.

The amount of thermal NO_X produced is related to fuel type, burning zone temperature, and oxygen content. Therefore, raw materials that are hard to burn (i.e., materials that require more heat input per ton of clinker produced) generate more NO_X.

Fuel NO_X

Fuel NO_X is the result of oxidation of nitrogen compounds in fuel. Fuel nitrogen is only partially converted into NO_X during combustion. The amount formed depends on fuel type, precalciner type and precalciner temperature. NO_X formed in the secondary combustion zone, primarily fuel NO_X (Gardeik, 1984), depends on:

- Nitrogen concentration in the fuel,
- Oxygen concentration in the combustion zone,
- Initial NO concentration in the combustion gas,
- Volatile concentration in the (solid) fuel, and
- Temperature in the secondary combustion zone.

As opposed to the burning zone of the kiln, where higher temperatures result in much higher NO_X formation, higher temperatures (up to 1100°C) in the precalciner may actually reduce NO_X emissions when a fuel containing nitrogen is used (Nielsen, 1990).

In the design of modern low-NO_X calciners, high temperatures and reducing conditions are proven methods for suppressing the formation of fuel NO_X generated in the precalciner, and for destroying thermal NO_X generated in the burning zone of the rotary kiln (Keefe and Shenk, 2002).

Feed NO_X

NO_X emissions can also result from the oxidation of nitrogen compounds in the raw material feed to the kiln (feed NO_X). The range of nitrogen concentrations in various kiln feeds is 20-1000 ppm (Gartner, 1983) and the potential contribution of feed NO_X to total NO_X emissions is 0.2-10 lbs of NO_X per ton of clinker.

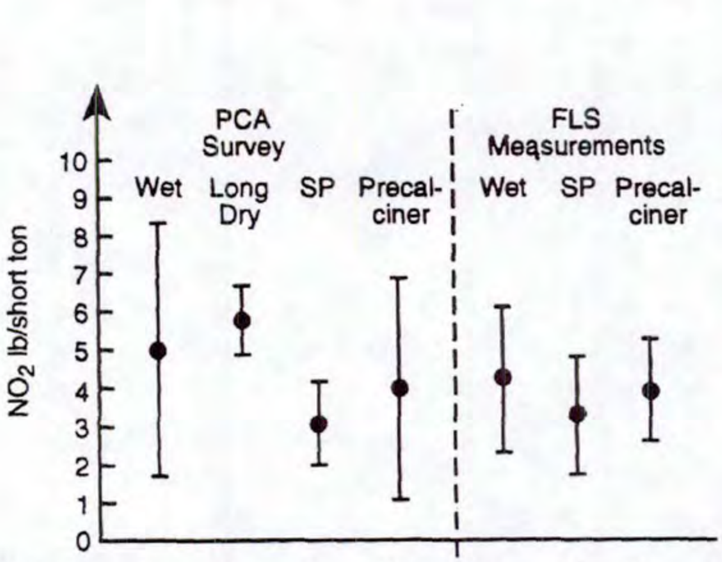
Up to 50% of feed nitrogen may be converted to NO_X, if raw materials are heated slowly: with rapid heating, the conversion rate is much lower.

The following conclusions can be made for rotary kiln systems (Young and von Seebach, 1999):

- Formation of thermal NO_X in the burning zone is the major contributor to NO_X emissions from the kiln
- Fuel NO_X is the major contributor in the secondary combustion zone of precalciner and riser duct fired preheater kilns
- Feed NO_X is usually a minor contributor to the total NO_X generated in rotary kiln systems.

It should be further noted that, due to the dynamic nature of kiln operations, NO_X formation can be highly variable so each kiln will tend to have unique NO_X emission characteristics, inherent to the variability in cement manufacturing process. Figure IV-2 illustrates the wide range of NO_X emissions from different types of kilns.

NO_X emissions rates are also site- and kiln-specific, and may be quite dissimilar between two apparently identical kilns, for causes not fully understood, but, probably connected to the raw materials used. Other causes for NO_X emissions rate differences may result from different types or classes of cement products being produced; chemical variations between these different products can influence cement kiln operating parameters and thus NO_X emissions. Short-term process transients such as kiln feed rates and fuel quality also affect NO_X emissions. All of these factors can influence the applicability and costs of incorporating NO_X controls.



Number of Kilns	8	3	3	10	7	13	7
Average	4.97	5.70	2.98	3.86	4.07	3.13	3.77
Standard Deviation	3.28	0.85	1.05	2.89	1.89	1.57	1.31

Figure IV-2. NO_X emissions for various cement kiln types (USEPA, 1994). (SP: Suspension Preheater kilns)

NO_X Control Techniques

There are two broad categories of NO_X reduction techniques for cement kilns: 1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_X in the manufacturing process (modifications for cement kilns include low-NO_X Burners (LNB), secondary combustion, and staged combustion); and 2) post-combustion (secondary) controls, where flue gases are treated to remove NO_X that has already been formed.

It should be noted that the quality of clinker produced in a kiln varies with characteristics of the combustion, so primary controls need to be selected carefully. Dry low-NO_X (DLN) operation, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NO_X. Low excess air and air-staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a LNB has been successfully used in some facilities, including California Portland Cement. Low-NO_X combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter).

The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NO_X.

LNBs can be used when indirect firing is employed. When implementing indirect firing with LNBs, other process improvements are often implemented, such as better process controls. According to Portland Cement Association (1998), 20%-30% NO_X reductions can be achieved from the use of indirect firing with LNBs and associated process modifications.

Combustion modifications are less successful at reducing NO_X emissions in thermal processing applications (like cement kilns) than in boilers for steam and/or power production. Chemical reactions producing cement clinker require high material and gas temperatures, and product quality also requires an oxidizing atmosphere in the combustion zone of a cement kiln. Excessively high temperatures in the burning zone pose equipment damage risk, while temperatures too low will no longer produce a salable product.

NO_X emissions can also be affected by kiln feed chemical characteristics, feed chemical uniformity, and specific fuel consumption. As stated by EPA's NO_X Alternative Control Technique Document for the Cement Manufacturing Industry (USEPA, 1994), "For any given type of kiln, the amount of NO_X formed is directly related to the amount of energy consumed in the cement-making process. Thus, measures that improve the energy efficiency of this process should reduce NO_X emissions in terms of lb of NO_X / ton of product."

Following are some of the more common process modifications that have been made to reduce NO_X emissions from cement kilns (NESCAUM, 2001):

- Changing fuel (e.g. natural gas to coal firing).
- Improving kiln feed chemical uniformity, for more stable kiln operations:
  - Modifications to quarry operations,
  - Raw material blending facilities, and
  - On-line analytical control systems for raw material proportioning (e.g. kiln feed blending systems).
- Modifications to improve thermal efficiency, including:
  - Reducing excess air infiltration,
  - Increasing efficiency of cyclones in preheater kilns,
  - Reducing the amount of moisture in slurry (wet process kilns only),
  - Revising kiln chain systems in long wet or long dry kilns,
  - Modifying or replacing clinker coolers to improve heat recovery and cooler efficiency,
  - Initiating operator training programs, and

  - Returning as much cement kiln dust (CKD) as possible to the kiln system (without adversely affecting product quality).

- Installing or upgrading kiln system sensors and instrumentation.
- Installing or upgrading computer controls of kiln systems to stabilize kiln operation and avoid burning zone temperature variations.

According to Young and von Seebach (1999), industry data and experience show that control of burning zone temperature is the primary process control method applicable to lowering thermal NO_X formation. Process modifications that allow better control of the kiln burning zone temperature will result in reducing thermal NO_X formation and minimizing NO_X spikes. Stable kiln operation, through feed chemical uniformity, results in overall NO_X reductions of 10% - 15%, while poor kiln feed chemical uniformity results in overfiring the kiln, and higher NO_X emissions.

Fuel Switching

Switching to a lower-nitrogen fuel in a precalciner may reduce NO_X emissions, but the nitrogen content of the fuel burned in the burning zone has little or no effect on NO_X generation. Generally, no relationship has been found between fuel nitrogen content and the NO_X emissions from a cement kiln (Miller and Egelov, 1980).

Process Optimization and Automated Control

Process optimization is a common method for reducing NO_X emissions from cement kilns. In principle, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NO_X generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NO_X control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NO_X reductions reported in this Chapter are generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions reported in a case study (NESCAUM, 2001) equivalent to 55% reduction in average NO_X emissions - from 845 lb/hr to 383 lb/hr – were achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NO_X reduction for an overall NO_X emission reduction of 59% from controls.

Flue Gas Recirculation

Flue gas recirculation (FGR) or water/steam injection into the main flame to reduce flame temperatures and NO_X formation is not a viable method of reducing NO_X in a cement kiln burning zone. FGR's effectiveness relies on cooling the flame and generating an oxygen deficient (reducing) atmosphere for combustion to reduce NO_X formation, conditions that are not compatible with cement kiln operation. High flame temperature and an oxidizing atmosphere are process requirements to produce a quality clinker product.

Indirect Firing

Conversion from a direct coal firing system to an indirect firing system kiln with a low NO_X burner may result in NO_X reductions ranging from 0% to about 20% (Kupper et al., 1990; Schrsemli, 1990). Incorrect use of multi-channel (low NO_X) burners can increase NO_X rather than reduce NO_X, and it has been found (Hansen, 1985) that less excess air in the kiln combustion gases results in less NO formation at the same burning zone temperature. NO_X reductions of 15% were reported.

Low-NO_X Burners

LNBs have been successfully used in the primary burn zone and especially in the precalciner kilns.

Secondary combustion zones have proven effective at reducing NO_X emissions in cement kilns. In long kilns, secondary combustion can be partly accomplished by mid-kiln injection of fuel (less than 20% of kiln fuel). NO_X emissions are reduced because less fuel is burned in the high temperature environment of the burning zone. Another NO_X reducing technique is the use of fuel in the riser duct of preheater kilns, although, because of high prevailing temperatures, such reductions do not always occur. With precalciner kilns, which employ a secondary combustion zone at a much lower temperature than the burning zone, typically 60% of the fuel is burned in the precalciner, with the combustion air coming directly from the clinker cooler, and NO_X emissions for these kilns are less than from long wet, long dry, or preheater kiln systems because 60% of the total fuel requirement is burned under lower temperature conditions where negligible amounts of thermal NO_X are formed. Furthermore, precalciner kilns have the potential for staged combustion as a NO_X control technique. All major equipment suppliers offer "low-NO_X" precalciner designs. Fuel burned in a sub-stoichiometric O2 environment creates a strongly reducing atmosphere (relatively high concentrations of CO) that inhibits formation of fuel NO_X and destroys a portion of the NO_X formed in the kiln burning zone. Additional tertiary combustion air is added later to complete combustion of the fuel.

Staged combustion has become a well-known method for reducing NO_X emissions from cement plants, but as NO_X and CO emissions limits become more stringent, control via fuel and air staging are coming under reconsideration. Low- NO_X calciners combine high temperature combustion and firing under reducing conditions without staging fuel/air.

Low-NO_X Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner can be low enough to reduce thermal NO_X but still be effective in heating the limestone.

Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NO_X reductions can be substantial. All new precalciner kilns are equipped with low-NO_X burners in the precalciner. Low-NO_X precalciners have been shown to reduce NO_X by 30%-40% compared to conventional precalciners (Young and von Seebach, 1998). This reduction is from the precalciner-generated NO_X, not for the entire kiln.

Several precalciner kilns in the U.S. have recently been retrofitted with these "two-NO_X" calciners, and several new kiln lines have been installed using low-NO_X precalciner technology. Operating experience indicates a noticeable reduction in NO_X per ton of clinker. Industry reports place the NO_X reduction potential of staged combustion with a low-NO_X precalciner at 30% - 40% when compared to a conventional precalciner kiln system.

Low-NO_X precalciner is a proven way to reduce NO_X emissions in a cement-making system, and all new cement-making systems are expected to be built with it. They come in two types, "in-line", commonly used with "normal" fuels (e.g. coal, oil, gas), or "separate-line", selected for difficult-to-burn fuels (e.g. petroleum coke and anthracite) because its high oxygen atmosphere ensures improved fuel burnout. In-line calciners have lower specific NO_X emissions than separate-line ones, but both are capable of meeting current CO/NO_X emission standards for any combination of fuel and feed, and both are dependent on the presence of strong reduction and oxidation zones.

CemStar

Another approach that has been proven effective in reducing NO_X is the patented CemStar process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures (Young, 1995; Young, 1996). In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment.

The CemStar approach has many advantages: energy input can be reduced, NO_X emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NO_X generation. NO_X reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NO_X is high due to thermal NO_X, CemStar is likely to provide reductions on the order of 40%-50%. Results of controlled testing of CemStar with baseline conditions resulted in 20% reduction in NO_X, corresponding with a reduction in average burn-zone temperature of over 200°F. Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

TXI, the developer of CemStar, reports that more than 10 plants are currently equipped with the technology. NESCAUM (2001) discusses one application of CemStar on a long-wet process kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NO_X by about 30% with mid-kiln heat input comprising about 20% of the total heat input (Portland Cement Association, 1998). Results of tests of mid-kiln firing on several kilns are summarized in Table 2 (NESCAUM,2001). The average NO_X reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NO_X produced in the primary burn zone. Fuel NO_X will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar (Schrama et al., 1995; Stillwater and Wahlquist, 1998). Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.

Table IV-2 NO_X Reduction at Cement Kilns Using Mid-Kiln Technology (NESCAUM,2001)

Initial NO_X (ppm)	936	1372	1342	1359	565	513
Final NO_X (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

High-pressure air injection, mentioned in the previous section as a potential control for SO_2 emissions, was primarily developed as a NO_X reduction strategy (Hansen, 2002). The technique was designed for use with staged fuel combustion (mid-kiln firing) and mixing air. Mid-kiln firing with mixing air creates stratified thermal layers in the kiln, preventing immediate combustion of the mid-kiln fuel and lowering exit oxygen levels enough that additional CO is produced. Injecting high-pressure air into the kiln provides energy to mix the layers, lowering the main flame temperature and creating a reducing area between the fuel and air injection points, which encourages the destruction of NO_X. The technique has been shown to reduce NO_X by about 50%, while also reducing CO by 47% and SO_2 by 97%.

Biosolids Injection

Biosolids Injection (BSI) is a technology that was developed in the 1990's by the cement industry for NO_X reduction in precalciner and preheater kilns (Biggs, 1995). BSI adds dewatered sewage sludge to the mixing chamber of the precalciner. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NO_X. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NO_X from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NO_X reduction, but it will depend on the specifics of the kiln.

Selective Non-catalytic Reduction

Selective Non-catalytic Reduction (SNCR) of NO_X is based on the injection of a reagent, typically NH3 or urea, into the kiln system at a location with an appropriate temperature window 1140 – 2010oF (870 - 1100°C). Some researchers have found that the most effective temperature range is narrower, about 1650 – 2000°F (900 - 1000°C). Temperature is critical because no catalyst is used. At temperatures too high, the reagents will form additional NO_X, and, at low temperatures, the reactions proceed slowly and promote the escape of substantial amounts of unreacted ammonia. Under optimum conditions about one mole of NH3 is required to reduce one mole of NO_X, but the amount of NH3 is always critically dependent on the reaction temperature. Ammonia slip, which increases rapidly when the molar ratio of NH3 to NO is above one, causes a detached plume and can increase opacity of the stack gases.

Preheater and precalciner kilns operate with kiln gas exit temperatures in the appropriate temperature range. SNCR systems have been used on some preheater kilns in Europe. For wet and long dry kilns, these temperatures exist midway through the kiln. Access to this area is possible only through ports in the kiln shell as used in mid-kiln firing or with scoops used to return cement kiln dust. Ammonia must be added continuously in a fixed molar ratio to NO_X in order to be effective and to minimize ammonia slip. Therefore, SNCR is not technically feasible at this time on long wet process or long dry process kilns.

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries (Steuch et al., 1994; Sun et al., 1994). Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table 3 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good.

Although SNCR technology has the potential to offer significant reductions on some precalciner kilns and it is being used in numerous cement kilns in Europe, it has been tested in only one facility in the U.S.

Table IV-3 NO_X Reduction Performance of Urea SNCR on Precalciner Cement Kilns (NESCAUM, 2001)

Company / Location	Unit Type	Size (MMBtu/hr)	NO_X Baseline	Reduction (%)	NH_3 SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Precalciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Precalciner	260 697 658	1.29 lb/MMBtu 1.58 lb/MMBtu 0.92 lb/MMBtu	50 45 25	15 15 15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm^3 500 ppm	90	na

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) uses ammonia, in the presence of a catalyst (e.g. titanium dioxide; vanadium pentoxide), to selectively reduce NO_X emissions from exhaust gases. SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the U.S. Typically, anhydrous ammonia, usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NO_X is reduced to N_2 gas and water. The optimum temperature for SCR depends on the catalyst but is usually between 570 and 840°F (300 and 450°C).

Exit gas temperatures from dust collectors on wet kilns, for long dry kilns, and for dust collectors in preheater kilns that use in-line raw mills for grinding and drying raw materials are relatively low and flue gases would have to be reheated before employing SCR. This technology so far has not been applied to the cement kilns but is being evaluated by some of the state air permitting agencies as Best Available Control Technology (BACT) for some of the new cement kilns being proposed in the U.S.

Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, one of the case studies in *Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness* (NESCAUM, 2001) combines indirect firing and mid-kiln firing to reduce NO_X by a combined amount approaching 50%. It is also reasonable to expect that technologies such as CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits, and it may be feasible to use SNCR or SCR in combination with other controls for cement kilns. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NO_X reductions may not be additive.

4.3.3. $PM_{2.5}$ Controls

The particulate matter exiting the kiln system with the exhaust gases is relatively coarse, with most of the particuate matter having diameters greater than 10 microns, but the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading.

As is the case for many other industrial sectors, the main control options for fine particles are baghouses (more formally known as Fabric Filters) and electrostatic precipitators (ESPs), described in Section 2.3.2 (EGUs). The following section describes some issues specifically related to cement kilns and the use of these devices, including a new filter system combining a baghouse and an ESP.

Cement kilns primarily utilize baghouses of the reverse-air and pulse-jet types. Both types are usually configured so that the bags can be cleaned during an "off-line" cycle, in which a section of the baghouse is closed off from the main exhaust flow for cleaning. This tends to reduce the need for a high-pressure pulse that causes additional wear on the filtration fabric, allows less time for particles to be collected in the hopper during its brief and frequent use, and requires additional power for operation. The choice between a reverse-air and pulse-jet system is generally made on the basis of the volume of exhaust and production from the kiln. In general, kilns producing less than 1650 stpd (with exhaust volumes below 128,000 acfm) are most efficiently served by a jet-pulse system (D'Lima and Pirwitz, 2000). The decision is more complex for kilns up to 6600 stpd (with exhaust volumes up to 853,000 acfm), for which initial equipment costs are similar but lifetime operation costs are more complicated. D'Lima and Pirwitz (2000) concluded that jet-pulse systems are appropriate for the smallest kilns and reverse-air systems are preferred for all larger kilns, even though they may have higher installation costs for kilns of more modest size.

Corrosion in baghouses has been an important topic in the cement kiln control literature (Jansen and Mazeika, 2003; Biege and Shenk, 2001). A 2002 EPA rule [40 CFR Part 63 Subpart LLL (2002)] requires gas temperatures entering the control device not to exceed 400°F (205°C) in order to control dioxin emissions. Water sprays are usually utilized to control exhaust temperature, but adding water vapor to the exhaust stream while lowering exhaust temperature brings the gas near the dew point of some corrosive components. Corrosion issues can be addressed in a number of ways, but all add cost to the use of the control system.

The three components of corrosion are corrosive gases, condensation, and a corrodible surface; reducing any component will reduce corrosion. Corrosive gases can be reduced in a roller mill; this may be one of the most effective methods to reduce corrosion. Many of the gases are absorbed by the feed during the milling process and are therefore not available to form acids in the exhaust. Changing the feed may also reduce some of the acidic gases. Condensation is prevented most easily by keeping the exhaust temperature hot; however, when this is not allowed, it is best to maintain the exhaust temperature as high as possible, preventing drops which may allow acidic condensation. Insulating surfaces and carefully sealing unused sections of the control device can prevent exhaust from leaking into cool areas where it can condense and cause corrosion. Finally, corrosive-resistant materials and acid-resistant coatings can help reduce corrosion in control equipment.

Instead of a baghouse or an ESP, a combined system has become available, utilizing components of both systems. Whereas an in-series, hybrid system has the ESP and baghouse systems in independent compartments, this technology is described as "an ESP in which every other row of discharge electrodes is replaced by a single row of filter bags" (Gebert et al., 2003). In this new system, where the filter bags are directly adjacent or parallel to the ESP electrical field, ESP zones alternate with filter zones, allowing primary collection by the ESP and pre-ionization of the remaining dust for collection on the filter bags. A highly efficient expanded polytetrafluoroethylene (ePTFE) membrane is used as the filter fabric, which can remove an order of magnitude more of fine particulate than ordinary bags. During a pilot system test of a 225 m3/min (9000 acfm) slipstream from a coal-fired power plant in South Dakota, greater than 99.99% removal efficiency was shown. With the ESP fully engaged, bag cleaning was required only every 300 minutes, compared to every fifteen minutes when the ESP was not used. This system has been utilized in full-scale commercial operation at a cement kiln in Italy since September 2002, capturing dust from the cement kiln, raw mill and clicker cooler. Another similar filter is in operation since October 2002 at the coal-fired power plant in South Dakota mentioned above.

The synergy between the two technologies enables operation of the filter bags at high air-to-cloth (A/C) ratios, and, combined with the new compact size for filters, provides the following benefits for a cement plant:

- Ability to reach high control efficiencies in all operation modes,
- Continuous stable operation, and

- Lower operating costs, due to reduced number of system components.

4.3.4. VOC Controls

No controls which specifically targeted VOCs were identified for cement kilns.

4.4. Costs and Availability

4.4.1. Sulfur Dioxide Control

The SO_x control techniques applicable to the cement industry and the assumed SO_x reductions that the various control technologies can achieve are summarized in Table IV-4.

The achievable SO_x reductions vary greatly. Even when the same control technology is applied to kilns of the same type, the removal efficiency will depend on kiln operating parameters, uncontrolled SO_x emissions rate, and many other site-specific factors.

Wet-limestone scrubbers and spray dryers can be used as secondary control devices to reduce SO_2 emissions from a cement kiln.

Capital and operating costs for spray dryers and wet scrubbers as applied to cement kilns were computed by Young (2002). Both technologies were assumed to be installed *after* the existing APCD, which would allow the CKD to be recycled back to the kiln. If CKD is not recycled, there is a negative impact on the operating cost of the plant. Table IV-5 summarizes the capital and operating costs in terms of $ per ton of clinker produced for different types of kilns. The capital and operating costs of the spray dryer include a baghouse, new stack and new ID (induced draft) fan. The capital and operating costs for the wet scrubber include new fans and a new stack as well as a new wastewater treatment facility.

Another installation was made in 1998 at Castle Cement's Ribblesdale (UK) facility (Castle Cement, 2004). Scrubber installation cost £5 million and operational costs are about £750,000 annually. Emissions from one unit were reduced by 90%.

Table IV-4 SO_2 Control Techniques Applicable to Cement Kilns (Miller, 2001)

SO_2 reduction technique	Applicable to kiln type				Range of removal efficiency
	Long wet	Long dry	Preheater	Precalciner	
Process alterations	x	x	x	x	0-100%
Dry reagent injection			x	x	25-85%
Hot meal injection			x	x	0-30%
Spray dryer absorber		x	x	x	50-90%
Wet SO_2 scrubber	x	x	x	x	80-95%

Table IV-5 Capital and operating costs of spray dryers and wet scrubbers applied to cement kilns (Young, 2002)

		Spray Dryer		Wet Scrubber	
	Clinker capacity, tpy	Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker	Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker
Small wet kiln	300,000	\$54.67	\$20.02	\$47.00	\$22.59
Medium wet kiln	600,000	\$38.17	\$14.09	\$32.67	\$17.58
Medium dry kiln	600,000	\$39.75	\$14.79	\$31.83	\$17.21
Large dry kiln	1,200,000	\$23.17	\$9.43	\$20.42	\$13.05
Medium preheater kiln	600,000	\$17.92	\$7.51	\$15.83	\$9.85
Medium precalciner kiln w/ bypass	600,000	\$25.17	\$10.20	\$19.33	\$11.42
Large preheater kiln	1,200,000	\$10.96	\$5.41	\$10.83	\$8.14

An alternative secondary control device for SO_2 was designed and applied as part of U.S. Department of Energy's Clean Coal Technology program. A co-project of Passamaquoddy Technology and Dragon Products Company in Thomaston, ME, the Passamaquoddy Technology Recovery Scrubber™ (Recovery Scrubber™) utilizes cement-kiln dust as a reagent for removing SO_2 from kiln exhaust gases (USDOE, 2001). Waste heat from the kiln is used to crystallize K_2SO_4, a saleable, fertilizer-grade by-product. The remaining cement kiln dust is returned to the kiln, significantly reducing particulate emissions, eliminating the need for removal of the dust to a landfill, and reducing the requirement for raw materials by about 10 percent. Sulfur dioxide was reduced by 82 to 98.5%, depending on scrubber inlet SO_2 rates. In addition, NO_X was reduced by about 25% and VOCs by 70%. Capital costs for a Recovery Scrubber^{TM} were estimated at about $10.5 million in 1996 dollars, with operating and maintenance costs of $150,000 per year and electricity costs of $350,000 per year (787 kW at $0.06/kW).

4.4.2. Nitrogen Oxides Control

Table 6 presents a summary of NO_X controls that are feasible for cement kilns, the range of potential NO_X reductions from applying these controls, the cost effectiveness of the controls, and effects on other emissions when using these controls.

Table IV-6 Summary of the Feasibility of NO_X Controls for Cement Kilns

NO_X Reduction Technique	Technical Feasibility	NO_X Reduction Potential (%)[1]	Cost Effectiveness ($/ton NO_X removed)	Effect on Other Emissions	Reference
Process Modifications	In full-scale use	0 - 30 [15]	3,100 - 8,800	Unknown	16
Low NO_X Burners w/ Indirect Firing	In full-scale use	0 – 20 [10]	5,800 - 8,100	Unknown	16
Low NO_X Burners w/ Indirect Firing and Mid-kiln Tire Injection	In full-scale use	[49]	1 - 1,800	Unknown	17
Mid-Kiln Injection of Fuel, Riser Duct Firing Calciners	In full-scale use	0 – 30 [15]	5,100 -11,500	May increase CO, SO; hydrocarbon emission	16
CemStar	Wet kilns	20 - 50 [20]	0-600	Unknown	17
Low NO_X Precalciner	Have been installed on several full-scale kilns - Offered by several different vendors.	30 – 40 [30]	2,700 - 3,600	May Increase emissions CO, S02, and/ or hydrocarbons	16
SNCR	May be applicable only on preheater or precalciner kilns - limited data	15 – 65 [45]	900 - 1,200	May Increase emissions CO, NH3, and NH4+salts (detached plume)	17
Biosolids Injection	May be applicable only on preheater or precalciner kilns - limited data	[50]	100-1,800	May Increase emissions CO, NH3, and NH4+salts (detached plume	17

[1] Values in brackets are the assumed NO_X reductions used to calculate the estimated cost effectiveness of each Technology.

4.4.3. $PM_{2.5}$ Control

As discussed above, control of particulate matter in cement kilns is accomplished using baghouses and electrostatic precipitators. These processes are also used in electric utility generating units and industrial boilers. Capital and operating costs for fabric filters and ESPs as applied to cement kilns were computed by Young (2002) and are summarized in Table IV-7. The costs include the addition of a new fan.

Table IV-7 Capital and operating costs of baghouses and ESPs applied to cement kilns (Young, 2002)

		New ESP		New baghouse	
	Clinker capacity, tpy	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**
Small wet kiln	300,000	$14.00	$3.35	$16.67	$3.81
Medium wet kiln	600,000	$11.00	$2.49	$13.00	$2.92
Medium dry kiln	600,000	$10.50	$2.54	$12.00	$2.78
Large dry kiln	1,200,000	$7.33	$1.51	$8.67	$1.96
Medium preheater kiln	600,000	$4.33	$1.03	$5.17	$1.17
Medium precalciner kiln w/ bypass	600,000	$5.33	$1.42	$6.33	$1.53
Large preheater kiln	1,200,000	$3.33	$0.74	$4.00	$0.90

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5. KRAFT PULP MILLS

5.1. Description of pulp and paper processes

Kraft pulping processes consists of wood preparation, pulping, pulp washing, oxygen delignification and/or bleaching of pulp and chemical recovery as illustrated in Figure V-1. Beginning with wood preparation, logs are debarked, ground into wood chips, and then screened to remove chips of unacceptable sizes. During the pulping process, the wood chips enter the digester where they are cooked with liquor and broken down into a pulp slurry. The pulp slurry is transferred to a blow tank while the spent liquor is sent to a flash tank. The pulp slurry then enters the pulp washing process where knots, shives, and short fibers are removed, spent cooking chemicals are recovered from the pulp slurry, and the pulp slurry is thickened for later processes. Next, the pulp enters the oxygen delignification process where the lignin content of the pulp is reduced to increase brightness of the pulp. The brightness of the pulp is further enhanced by bleaching, a multi step process that removes residual lignin by using chemicals to oxidize and dissolve the lignin compounds. Lastly, the chemical recovery process recovers the spent cooking liquor using the following methods: evaporation to reduce water content in spent liquor, combustion of concentrated spent liquor, and recovery of chemicals from

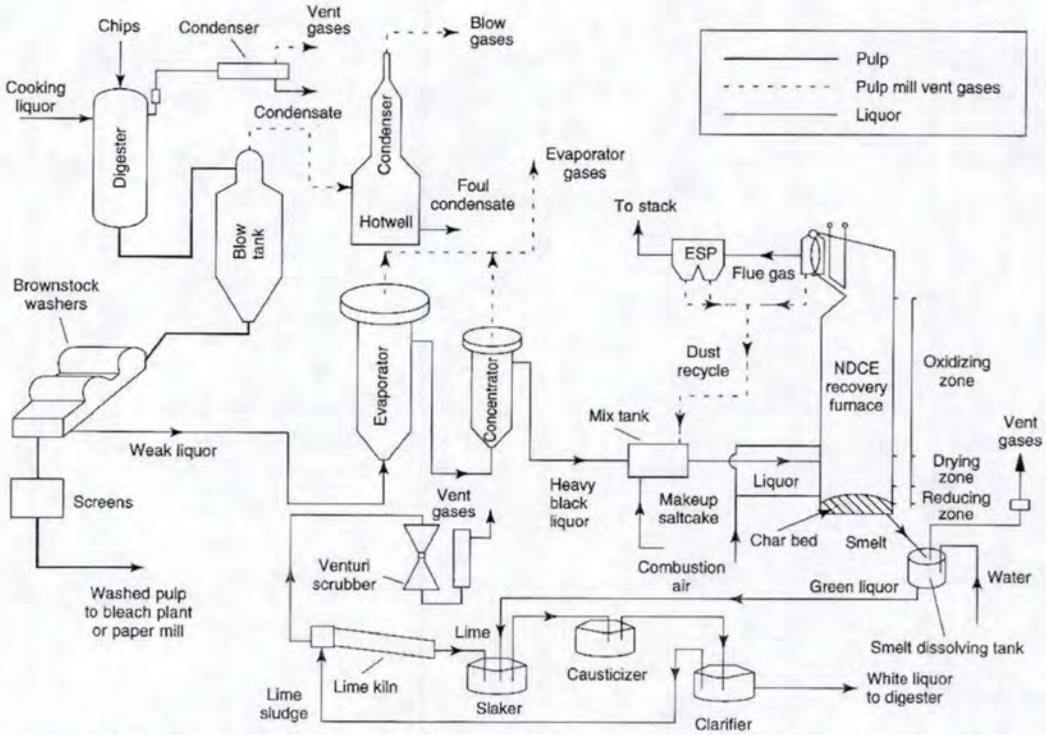

Figure 1. Schematic of the Kraft Pulping and Recovery Process (Someshwar and Pinkerton, 2000).

combustion products. The regeneration of lime, which is used for recovering sodium, is an additional step of the kraft chemical recovery process not found in the acid sulfite, mechanical, or semi chemical processes.

Acid Sulfite and semi chemical processes are very similar to the kraft process, however, the acid sulfite process differs from the kraft process in the type of cooking liquor used and the semi chemical process differs from the kraft process in the use of lower temperatures, more dilute cooking liquor or shorter cooking time, and mechanical disintegration. Mechanical pulping uses high-energy refining systems to produce pulp from chips and bleaching agents are used to decolorize lignin instead of removing lignin. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.2. Review of BART-Eligible Pulp and Paper facilities in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities.[7] *[Editor's note: additional facilities may be added after NY and PA have completed their inventory].*

Table V-1 BART-eligible pulp and paper facilities.

State	Company/Facility	City/Town	Category
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp

5.3. Available Control Technologies

The pulp and paper production, consisting of chemical, mechanical, and semi chemical processes, has a number of potential sources of SO_x, NO_X, particulates, and VOC emissions (Pinkerton, 2000). The major chemical wood pulping processes are kraft, acid sulfite, and semi chemical pulping. Kraft pulping accounts for 80% of the

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[7] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

pulp produced in the U.S, mechanical and semi chemical pulping, for 10% and 6%, respectively and sulfite or soda chemical process accounts for the remaining pulping capacity (Someshwar and Pinkerton, 2000).

A variety of technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the main (or targeted) pollutant. The sections below will describe the potential sources of significant SOx, NO_X, particulates, and VOC emissions in the major pulping processes and the measures used to control them.

5.3.1. SO_2 Controls

In a kraft mill, SO_2 is a product of the incineration of black liquor in the recovery furnace; black liquor is made up of 3-5% sulfur by weight of dissolved solids. The majority of the sulfur exits the furnace in the smelt; however, typically less than 1% can be emitted as a gas or particulate, resulting in average SO_2 concentrations of 0-500 ppm in stack gases. Recovery furnace SO_2 emissions are a function of liquor properties such as sulfidity (sulfur-to-sodium ratio), heating value, and solids content; combustion air and liquor firing patterns; furnace design features; furnace load; auxiliary fuel use; and stack gas oxygen content. To reduce SO_2 emissions from the recovery furnace, the temperature in the lower furnace must be uniform. This has been achieved by optimizing liquor and combustion air properties and firing patterns. Reducing liquor sulfidity has also been used as a control strategy for SO_2 emissions. Flue gas desulfurization as an effective control strategy is uncertain due to the mostly low and unpredictable levels of SO_2 emitted.

In a lime kiln, SO_2 is produced from the combustion of fuel oil or non condensable gases (NCG). On average, lime kiln SO_2 emissions are very low due to the capture of SO_2 from the alkaline material inside the kiln and the venturi scrubber usually installed immediately after the kiln.

In semi chemical processes, only neutral sulfite semi chemical (NSSC) pulping emits SO_2 emissions as a result of the combustion of sulfur-containing semi chemical spent liquor in a fluidized bed combustor. Limited data shows an SO_2 emission factor for a fluidized bed combustor burning NSSC liquor as 1 lb SO_2/a.d. ton of pulp.

A major source of SO_2 in acid sulfite processes is from the digester and blow tank areas. During a hot blow, significant quantities of SO_2 can be released into the blow gases ranging from 10 to 70 pounds per ton of pulp. Using an alkaline solution to scrub the blow gases, 97% of SO_2 can be recovered and returned to the acid-preparation system. While this approach is possible using sodium and NH_3 bases, magnesium and calcium bases need slurry scrubbers deemed less practical. Scrubbing becomes impractical when during a cold blow, only 4 to 20 pounds SO_2 per pulp are released into the blow gases.

SO_2 can also escape from acid bisulfite washers and screens which can result in uncontrolled emissions generally ranging from 1 to 4 lb SO_2/ton pulp but can get up to as much as 16 lb SO_2/ton pulp. The gases emitted from the washers and screens are hooded and then directed to a direct-contact scrubber where the SO_2 is scrubbed from the gases. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.3.2. NO_X Controls

NO_X is produced from the incineration of black liquor in the kraft recovery furnace with black liquor containing 0.05% to 0.25% nitrogen by weight of liquor solids content. Normal NO_X emissions from kraft recovery furnaces are less than 100 ppm. NO_X emissions are mainly a result of fuel NO_X since the maximum temperature in the recovery furnace is approximately 2400°F and the temperature required for formation of significant amounts of thermal NO_X is greater than 2800°F. NCASI studied the origins of NO_X emissions from kraft recovery furnaces and concluded that the two most important factors affecting NO_X emissions, in order of importance, were the black liquor nitrogen content and excess oxygen in the zone where most of the liquor combustion occurs. Since it is difficult to alter the liquor N content, the best approach to minimizing NO_X in recovery furnaces is staged-air combustion. Currently, most recovery furnaces already optimally use staged combustion and emit less than 100ppm NO_X.

NO_X is produced in the kraft lime kiln from the combustion of fossil fuels, such as natural gas and residual fuel oil. Due to the design of the lime kiln, SNCRs and SCRs are not viable NO_X reduction techniques. Installing Low-NO_X Burners (LNBs) is also not a practical NO_X reduction technique according to a BACT analysis conducted on a new lime kiln in 1997. The installation of LNBs had a negative influence on the efficiency, energy usage, and calcining capacity of the lime kiln. Hence, like the recovery furnace, combustion modification such as decreasing excess air is the best way to reduce NO_X emissions. However, since the mechanisms of NO_X formation and NO_X emission reduction are not completely known, NO_X reduction strategies should be considered on a case-by-case basis.

Some NO_X emissions result from the burning of stripper off gases (SOGs) with significant ammonia and methanol content and combustion of NCG in the kiln, thermal oxidizer, or boiler. When SOGs containing methanol and ammonia are incinerated, the ammonia could potentially oxidize to produce NO_X. NH_3 will oxidize to NO_X when injected into gases above 2000°F to 2200°F, reduce NO_X to N_2 when gas temperatures range from about 1600°F to 2200°F, and remain as NH_3 in temperatures below 1600°F. However, the degree of NH_3 conversion to NO_X and the expected baseline level of NO_X emissions from pulp process units burning NCG and SOGs are not known.

NO_X emissions are expected during combustion of liquor in recovery furnaces for both semi chemical and acid sulfite processes. (Pinkerton, 2000; Someshwar, 1999).

5.3.3. $PM_{2.5}$ Controls

Measurable particulate emissions sources in a kraft mill are recovery furnaces, smelt-dissolving tanks, and lime kilns while fugitive particulate emissions sources are coal piles, paved and unpaved roads, bulk material handling such as lime, limestone, or starch, and wood handling. Particulate emissions from recovery furnaces are controlled by ESPs with particulate removal efficiencies of 90% in older units and 99% in newer units. Demister pads, packed towers or venturi scrubbers are used to achieve particulate emissions control in smelt-dissolving tanks, and venturi scrubbers and ESPs are used for control in lime kilns. Controlled mean particulate emission factors from smelt dissolving tank vents and kraft lime kilns are 0.13 lb/ton black liquor solids and 1.82 lb/ton of reburned lime product, respectively. Fugitive emissions are controlled by wetting; using chemical agents, building enclosures, and windscreens; paving or wetting roads; and modifying handling equipment.

In semi chemical processes, particulate emissions only become a concern when recovery furnaces are used. These emissions are controlled by using ESPs, wet ESPs or venturi scrubbers. In acid sulfite processes, the burning of both ammonium and magnesium base liquors will result in the release of particulate matter in the form of ammonium salts and magnesium oxide, respectively. The ammonium salts are removed when the flue gas exiting the absorption unit enters a series of fabric mesh pads called "candles." The magnesium oxide particulates are removed using multiple cyclones, a series of 3 or 4 packed tower absorbers, and in addition, some mills use venturi scrubbers and/or a SO_2 scrubber. Controlled particulate emissions of ammonia salt particles are <0.5 gr/dscf @ 8% O2 and for magnesium oxide, 0.05 to 0.1 gr/dscf correct to 8% O2. (Someshwar and Pinkerton, 2000).

5.3.4. VOC Controls

VOC emissions sources in a kraft mill are recovery furnaces and lime kilns. In a recovery furnace, VOC emissions are produced from incomplete combustion or from the contact between the black liquor and flue gas where volatile material from the liquor can transfer to the flue gas. Factors that affect recovery-furnace VOC emissions are the level of excess air used and the degree of mixing achieved within the furnace. To lower recovery-furnace VOC emissions, the residence time, oxygen content, temperature, and level of turbulence in the furnace combustion zone must be increased. However, increasing these parameters will increase NO_X emissions.

VOC emissions from lime kilns are also produced from incomplete combustion. In addition, VOC emissions can be a result of VOCs entering the kiln with the liquid part of the lime mud and VOCs being present in the scrubber makeup water. These additional VOCs are then emitted into the flue gas when the lime mud is heated and the flue gas exiting the kiln strips the VOCs from the scrubber makeup water. VOC emissions from lime kilns tend to be small with the majority being methanol.

In semi chemical and acid sulfite pulping processes, VOC emissions are a product of incomplete combustion in the fluidized bed combustor or in a specialized recovery furnace. Semi chemical VOCs can also be introduced into the flue gas if flue gas comes in contact with pulping liquor. VOCs from both semi chemical and acid sulfite pulping processes can enter the flue gas if the flue gas is able to strip organic compounds such as methanol from the scrubber makeup water. According to limited data, VOC emissions can significantly be reduced by improving combustion conditions and controlling liquor firing.

Mechanical pulping processes only emit VOCs and steam into the atmosphere. The VOCs in wood are emitted with the steam when wood undergoes cooking and refining processes. A study conducted by NCASI showed that VOC emission rates were proportional to steam emission rates. This data suggests that in order to decrease VOC emissions, the temperature in the exhaust gas must be reduced below the boiling point of water. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.4. Costs and availability

According to John Pinkerton at the National Council of the Paper Industry for Air and Stream Improvement (NCASI) (Pinkerton, 2004), pulp and paper industry representatives have been working with several engineering firms to evaluate to assess the costs and emission reduction potential of SO_2 and NO_X control technologies. Many of the technologies are candidates for evaluation as part of a BART site-specific engineering analysis. Particulate matter (PM) control strategies were also evaluated by NASCI. Information on applicability and cost is summarized in Tables V-2 through V-5 for Kraft Recovery Furnaces, Lime Kilns, Wood and Wood/Gas boilers and Wood/Coal and Wood/Oil boilers.

Information on the technologies referenced in the tables was collected by NASCI based on installation of processes or evaluation of these processes as part of New Source Review (NSR) Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) analyses, state Reasonably Available Control Technology (RACT) evaluations in ozone non-attainment areas, the USEPA NO_X SIP Call, or for other reasons.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well at to the achievable emissions reductions. Hence the range of costs cited in the tables.

Table V-2 Reduction of NO_X, SO_2 and PM in Kraft Recovery Furnaces (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Type of furnace, operating practices, black liquor solids concentration.	Type of furnace, operating practices, nitrogen content of black liquor, black liquor solids concentration.	Type of furnace, ESP efficiency
Current Emission Levels	~0 to 300 ppm	40 to 130 ppm	0.01 – 0.1 gr/dscf
National Emission Standards	none	none	1978 NSPS, 2001 MACT Existing Source – 0.044 gr/dscf. New source MACT is 0.015 gr/dscf
Recent BACT Determinations	50 to 300 ppm	75 to 150 ppm	0.021 to 0.044 gr/dscf
Current Installed End of Pipe Control Technologies	none	none	ESPs
Control Options	Optimize, on site-specific basis, liquor solids and operating practices; install SO_2 scrubber	Staged combustion practices (very site-specific)	Larger ESPs
Applicability of Control Option and Potential Emission Reductions	Scrubbing possible on some units to reduce SO_2 to as low as 10 ppm. Some units have emissions this low or lower at present.	SNCR and SCR not demonstrated as technically feasible.	Larger ESP possible on some units, although retrofit costs highly site-specific. Depending on current ESP design and condition, replacement or expansion of existing ESP can be considered
Cost of Option	Capital $8 million (1.7 MMlb/day BLS DCE unit; $12.8 million (3.7 MMlb/day BLS NDCE unit); Operating costs of $1.1 to $1.3 million (1.7 MMlb/day unit), or $1.6 to 1.8 million/yr (3.7 MMlb/day unit). Lower operating costs are for achieving 50 ppm; higher for achieving 10 ppm. Costs are very site-specific.		Replacement of ESP to achieve 0.015 gr/dscf PM emissions: for a 3.7 MMlb BLS/day NDCE furnace - Capital $29.3 million; operating $1.9 million/yr; for a 1.7 MMlb BLS/day DCE unit: $18.4 million capital; $1.2 million/yr operating. Costs are very site-specific.

Table V-3 Reduction of NO_X, SO_2 and PM in Lime Kilns (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Emissions are minimal due to alkaline nature of lime in kiln	Type of fuel (gas vs. oil), operating temperatures, nitrogen content of oil and oxygen availability in flame zone, burning NCGs	Type of control device and control device efficiency
Current Emission Levels	~0 to 20 ppm	0.05 to 0.4 lb/10^6 Btu heat input	0.01 – 0.2 gr/dscf
National Emission Standards	none	none	1978 NSPS – 0.067/0.13 gr/dscf (gas/oil); 2001 MACT Existing Source – 0.064 gr/dscf. New source MACT is 0.01 gr/dscf
Recent BACT Determinations	30 to 80 ppm	100 to 220 ppm	0.015 to 0.13 gr/dscf
Current Installed Control Technologies	none	none	Wet scrubbers, ESPs
Control Options	Wet scrubber with supplemental caustic control	none	Replace wet scrubber with ESP
Applicability of Control Option and Potential Emission Reductions			ESPs have higher removal efficiencies than wet scrubbers; all lime kilns installed in last ten years have ESPs rather than scrubbers. Average ESP emissions are on the order of 0.01 gr/dscf.
Cost of Option			Replacement of scrubber with ESP to achieve 0.01 gr/dscf PM emissions: for a 270 ton CaO/day kiln - $3.4 million; operating $0.2 million/yr.

Table V-4 Reduction of NO_X, SO_2 and PM in Wood and Wood/Gas-Fired Boilers (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Sulfur content of wood minimal	Type of boiler, wood nitrogen and moisture content, operating practices	Wood ash content, control device efficiency, operating practices
Current Emission Levels	0.025 lb/10^6 Btu is AP-42 emission factor	0.15 to 0.3 lb/10^6 Btu	0.05 to 0.6 lb/10^6 Btu
National Emission Standards	none	Subpart Db NSPS- none if gas capacity factor limited to 10% or less; gas capacity factor over 10% - 0.3 lb/10^6 BTU except 0.2 lb/10^6 BTU for new/reconstructed units after 1997	Subpart D, Db, Dc NSPS – 0.1 lb/10^6 Btu; final boiler MACT limit – 0.07 lb/10^6 Btu for existing, 0.025 lb/10^6 Btu for new solid fuel boilers
Recent BACT Determinations	0.01 to 0.045 lb/10^6 Btu	0.25 to 0.3 lb/10^6 Btu	0.02 to 0.1 lb/10^6 Btu
Current Installed Control Technologies	none	SNCR for base loaded boilers	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	none	SNCR for base loaded boilers	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions		SNCR has been installed on a few new wood boilers to achieve NO_X reductions in the 20 to 50% range. SNCR not appropriate for boilers with high load swings. SCR has not been applied.	ESPs in use on many wood boilers. Emission levels as low as 0.02 lb/10^6 Btu possible. Retrofit costs highly site-specific.
Cost of Option		Installing SNCR to achieve 0.15 lb/10^6 Btu NO_X emissions on a 300,000 pph wood boiler: Capital \$1.5 million; operating \$0.1 million/yr	Installing ESP to achieve 0.04 lb/10^6 Btu PM emissions on a 300,000 pph wood boiler: Capital \$21.3 million; operating \$1.4 million/yr. Costs to achieve a 0.065 lb/10^6 standard range from \$18.7 million to \$5.1 capital, \$900,000 to \$77,000 operating—highly site-specific
Control Option		Methane de-NO_X Reburn	
Applicability of Control Option and Potential Emission Reductions		Has been applied to one boiler burning wood, gas, and sludge. Involves natural gas injection and flue gas recirculation in stoker-type boilers only. NO_X reduction reported to be 40 to 50% in boilers burning high nitrogen content fuels.	
Cost of Option		Capital costs unavailable. Lower operating costs claimed due to increased boiler efficiency.	

Table V-5 Reduction of NO_X, SO_2 and PM in Wood/Coal and Wood/Oil-Fired Boilers (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Coal/oil sulfur content, ratio of wood to coal/oil	Type of boiler, coal/oil nitrogen content, wood nitrogen and moisture content, ratio of wood to coal/oil	Wood/coal/oil ash content, oil S level, control device efficiency
Current Emission Levels	Depends on fuel mix and coal/oil S content	0.25 to 0.7 lb/10^6 Btu	0.03 to 0.3 lb/10^6 Btu
National Emission Standards	Subpart D NSPS limits SO_2 to 1.2/0.8 lb/10^6 Btu (coal/oil); Subparts Db and Dc require percent reduction (except for very small boilers or those with low coal capacity factors) or use of very low S oil	Revised 1998 NSPS has 0.2 lb/10^6 Btu limit for boilers over 100 x 10^6 Btu/hr for all fossil fuels, limit applies if annual fossil fuel capacity factor exceeds 10%. Prior NO_X limits were fuel-type dependent and ranged from 0.3 to 0.7 lb/10^6 Btu for oil and coal.	Subpart D, Db, Dc NSPS – 0.1 lb/10^6 Btu unless annual wood capacity factor is less than 10%; final boiler MACT limit – 0.07 lb/10^6 Btu for existing, 0.025 lb/10^6 Btu for new solid fuel boilers
Recent BACT Determinations	0.3 to 0.5 lb/10^6 Btu	0.3 to 0.7 lb/10^6 Btu	0.03 to 0.1 lb/10^6 Btu
Current Installed Control Technologies	Alkaline scrubbing	SNCR for base loaded boilers, FGR, Low NO_X burners	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	Alkaline scrubbing	Low NO_X burners	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions	Generally applicable; reductions up to 90% possible	This option only available to pulverized coal/stoker boilers or oil/wood units. NO_X reductions in the 20 to 50% range can be achieved for the coal or wood contribution to total NO_X.	ESPs in use on many wood/coal and wood/oil boilers. Emission levels as low as 0.02 lb/10^6 Btu possible. Retrofit costs highly site-specific.
Cost of Option	Capital cost for scrubber installation following and ESP on a 300,000 pph wood/coal boiler - $7.4 to 8.2 million. Annual operating cost for 50% removal $1.0 million, $1.5 to 2.0 million for 90% removal.	Installing low NO_X burners to achieve a 0.3 lb/10^6 Btu level on a 300,000 pph wood/pulverized coal boiler: Capital $2.9 million; operating $0.15 million/yr. Retrofit costs site-specific.	Remove existing control device and install ESP to achieve 0.04 lb/10^6 Btu PM emissions on a 300,000 pph wood/coal boiler: Capital $5.1 to 20.5 million; operating $70,000 to 1.2 million/yr. Retrofit costs site-specific.
Control Option	Lower S content coal/oil; gas	SNCR for base loaded boilers	
Applicability of Control Option and Potential Emission Reductions	Generally applicable	Limited NO_X reductions possible, in the 20 to 40% range. SNCR not appropriate for boilers with high load swings.	
Cost of Option	Dependent on fuel prices	Capital cost of $1.5 million for a 300,000 pph wood boiler with limited coal or oil use; operating cost of $0.15 million/yr. Retrofit costs site-specific.	

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6. CONCLUSION

As states prepare to conduct BART determinations for their eligible facilities, preliminary information has been collected on the availability, costs and efficiencies of a variety of technology options. Depending on the requirements contained in the final BART regulations, anticipated for April 2005, states will have to decide what level of cost and what degree of visibility improvement is considered reasonable before completing BART determinations. MANE-VU has reviewed technology options for four of the 26 BART-eligible source categories. For EGUs, industrial boilers, cement plants and paper and pulp facilities, we present typical control options and costs. Facility specific reviews will be needed to determine specific controls and costs for each BART-Eligible source in the region.

6.1. EGUs

The presumptive level of control for previously uncontrolled EGU boilers as included in the proposed BART regulations include FGD (Scrubber) technology with an SO_2 control efficiency of approximately 95 percent. Chapter 2 points out that the average scrubber operating today does not achieve this level of control (existing scrubbers have a range of efficiencies between 30 and 97 percent); however, new installations are achieving rates even higher than 95 percent removal. Additional measures which can be considered for SO_2 control include the use of low-sulfur coal (compliance coal) (typically XX percent SO_2 reduction), spray dry adsorption (60-95 percent removal), dry scrubbing (40-60 percent removal) or circular fluidized-bed adsorption technology (80-98 percent removal). SO_2 control is highly cost effective with operational costs in the \$100-200 per ton range.

NO_X control technologies can be grouped into combustion controls (including low-NO_X burners (LNBs), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, burners-out-of-service, and air staging) and post-combustion controls (include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes). Combustion controls result in typical NO_X reductions of 15 to 60 percent, depending on the specific boiler and combination of controls. SCR achieves a 90-95 percent reduction whereas SNCR achieves 25-50 percent reduction in NO_X. Costs for NO_X removal range from \$200-500/ton for some of the low yield techniques to \$1000 to \$1500/ton for SCR with 90-95 percent removal efficiency.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called "baghouses"), and particulate scrubbers (PS). These technologies typically achieve greater than 95 percent removal of total particulate mass with over 80 percent removal of PM smaller than 0.3 um (with the exception of particulate scrubbers which achieve only 30-85 percent removal for this smaller size fraction). Mechanical collectors have even lower trapping efficiencies. PM controls are in place on virtually all EGUs already, hence the issue that will be faced in conducting BART determinations is how these existing controls will interface with proposed controls for other pollutants.

6.2. Industrial Boilers

For industrial boilers, many of the same control technologies for EGUs are applicable to this source category including: low sulfur coal, wet and dry FGD (or scrubber) technology for SO_2, combustion modifications and SCR and SNCR technology for NO_X, and ESP, fabric filter and wet scrubbing techniques for PM. However, industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus cost estimates for the same technologies will generally range, depending on the capacity of the boiler and typical operating conditions. High end cost estimates for NO_X removal can be over $10,000/ton.

6.3. Cement Kilns

Designing a system of emission controls for cement kilns are somewhat more complicated given that the quality of clinker produced in a kiln varies with characteristics of the combustion, it is possible to combine combustion technologies with post-combustion technologies for cement kilns in some cases and it is also possible to combine multiple combustion technologies on cement kilns. As a result, primary controls need to be selected carefully taking engineering and cost decisions into account for each specific kiln.

Control options for SO_2 include in-process removal, process changes (e.g. combustion optimization, flame shape adjustment or raw material changes), and the use of wet or dry scrubbers. For NO_X, both process modifications (e.g. combustion modifications, low-NO_X burners, secondary combustion or staged combustion) as well as post combustion controls need to be selected carefully. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading given that the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. In addition, PM technologies are affected by the presence of corrosive gases which can be reduced most effectively in a roller mill. While fabric filters (baghouses) and electrostatic precipitators are still the most common means of PM control at cement plants, a number of novel techniques and procedures are used to deal with the unique issues face by cement kilns.

Costs for SO_2 controls at cement kilns will vary widely depending on control options selected and process variables (e.g. whether material is recycled in the control process). Capital cost for typical wet/dry scrubbing post-combustion controls have been estimated in the $10-50/ton of clinker produced with operating costs in the $5-20/ton of clinker range. PM controls are similarly estimated in the $3-15/ton of clinker range for capital costs and $0-30/ton clinker for operating costs on an annual basis. NO_X has not been estimated on a per ton of clinker basis, but estimates vary between 0 and $10,000/ton of NO_X reduced.

6.4. Pulp Mills

Paper and pulp facilities have perhaps the widest range of operational configurations and thus possibilities for reducing pollutant emissions. A variety of technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions for some processes, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are presented as options.

For Kraft mill recovery furnaces, combustion modifications can be effective at reducing SO_2, NO_X, and VOCs. Reducing the liquor sulfidity can also help reduce SO_2 emissions. PM control for recovery furnaces is typically achieved through the use of ESPs or wet ESPs.

Lime kilns are also a significant source of visibility impairing pollutants; however, there are fewer options for effectively reducing SO_2 emissions. Combustion modifications can reduce NO_X and VOC emissions and Venturi scrubbers and ESPs are commonly used for PM control.

Demister pads, packed towers and Venturi scrubbers are used to reduce PM emissions from smelt dissolving tanks.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well at to the achievable emissions reductions. Hence a wide range of costs have been cited.

Appendix A: BART-Eligible Facilities in the MANE-VU Region

NESCAUM has conducted two previous studies to identify a comprehensive list of BART-eligible sources in the MANE-VU region (NESCAUM, 2001; NESCAUM, 2003). These studies have been carefully reviewed by permitting authorities in each of the MANE-VU jurisdictions and the sources listed in Table A-1 represent the list of sources identified through that process. Non-EGU sources for Pennsylvania and New York are still pending and should be available for inclusion in the Final Report.

Table A-1 BART-Eligible Facilities in the MANE-VU Region

State	Facility	Town/City	BART Category
Connecticut	Middletown		EGU
Connecticut	Montville		EGU
Connecticut	Norwalk Harbor		EGU
Connecticut	PSEG Power Connecticut LLC-Bridgeport Harbor		EGU
Connecticut	PSEG Power Connecticut LLC-New Haven Harbor		EGU
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Connecticut	PFIZER INC	Groton	chemical plant
Delaware	Edge Moor		EGU
Delaware	Indian River		EGU
Delaware	Mckee Run		EGU
Delaware	Citisteel	Claymont	iron and steel
Delaware	DuPont Edge Moor	Edge Moor	chemical plant
Delaware	Reichhold	Cheswold	chemical plant
Delaware	Motiva	Delaware City	petrol. storage
District of Columbia	Benning (PEPCO)	District of Columbia	EGU
Massachusetts	Brayton Point		EGU
Massachusetts	Canal		EGU
Massachusetts	Cleary Flood		EGU
Massachusetts	Braintree Electric		EGU
Massachusetts	Mystic		EGU
Massachusetts	New Boston		EGU
Massachusetts	Salem Harbor		EGU
Massachusetts	EASTMAN GELATINE CORP	Peabody	chemical plant
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY-KNEELAND STATION	Boston	boilers

Massachusetts	GULF OIL LP CHELSEA	Chelsea	petrol. storage
Massachusetts	REFUSE ENERGY SYSTEM COMPANY	Saugus	incinerator
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	EXXON EVERETT TERMIN (EXXON EVERETT MARKETING TERMINAL #240	Everett	petrol. storage
Massachusetts	GLOBAL PETROLEUM CORP.	Revere	petrol. storage
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maryland	C P Crane		EGU
Maryland	Chalk Point		EGU
Maryland	Dickerson		EGU
Maryland	Herbert A Wagner		EGU
Maryland	Morgantown		EGU
Maryland	Vienna		EGU
Maryland	EASTALCO ALUMINUM	Frederick	aluminum ore
Maryland	ST. LAWERENCE CEMENT(formerly Independent Cement)	Hagerstown	portland cement
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maryland	METTIKI COAL CORPORATION	Oakland	coal cleaning
Maine	William F Wyman		EGU
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Dragon Products	Thomaston	portland cement
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Katadhin - Mill W.	Millinocket	boilers
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
Maine	Gulf Oil - S Portland	South Portland	petrol. storage
New Hampshire	Merrimack		EGU
New Hampshire	Newington		EGU
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp
New Hampshire	Dartmouth College	Hanover	boilers
New Jersey	Hudson		EGU
New Jersey	CHEVRON PRODUCTS CO 18058	Perth Amboy	petrol. refinery
New Jersey	AMERADA HESS CORP PORT READING 17996	Woodbridge	petrol. refinery
New Jersey	BAYWAY REFINING CO 41805	Linden	petrol. refinery
New Jersey	COASTAL EAGLE POINT OIL COMPANY 55781	Westville	petrol. refinery
New Jersey	COLORITE SPECIALTY RESINS 45940	Burlington	chemical plant

New Jersey	GATX TERMINALS CORP CARTERET FACILITY 18010	Carteret	petrol. storage
New Jersey	GENERAL CHEMICAL CORP 07369	Newark	acid, sulfur, charcoal
New Jersey	GREEN TREE CHEMICAL TECHNOLOGIES INC 18185	Parlin	chemical plant
New Jersey	Griffin Pipe Products (45954)	Florence	iron and steel
New Jersey	Infineum USA LP- Bayway Chemical Plant (41767)	Linden	chemical plant
New Jersey	SHELL OIL PRODUCTS CO SEWAREN PLANT 18051	Sewaren	petrol. storage
New York	Arthur Kill		EGU
New York	Astoria		EGU
New York	Bowline Point		EGU
New York	Charles Poletti		EGU
New York	Danskammer		EGU
New York	E F Barrett		EGU
New York	Lovett		EGU
New York	Northport		EGU
New York	Oswego		EGU
New York	Ravenswood		EGU
New York	Roseton		EGU
New York	Samuel A Carlson Generating Station		EGU
New York	Consolidated Edison's 59th St Station		EGU
Pennsylvania	Bruce Mansfield		EGU
Pennsylvania	Brunner Island		EGU
Pennsylvania	Cheswick		EGU
Pennsylvania	Conemaugh		EGU
Pennsylvania	Eddystone		EGU
Pennsylvania	Hatfield's Ferry		EGU
Pennsylvania	Homer City		EGU
Pennsylvania	Keystone		EGU
Pennsylvania	Martins Creek		EGU
Pennsylvania	Mitchell		EGU
Pennsylvania	Montour		EGU
Pennsylvania	New Castle		EGU
Pennsylvania	Portland		EGU
Pennsylvania	Warren		EGU
Rhode Island	BROWN UNIVERSITY	Providence	boilers
Rhode Island	Clariant Corp.	Coventry	chemical plant

ATTACHMENT AA

Low-Sulfur Heating Oil in the Northeast States

Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues

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Disclaimer:

This document does not necessarily reflect the opinions of the Massachusetts Executive Office of Environmental Affairs.

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Executive Summary

The Northeast states are considering adopting a regionally consistent low sulfur standard for heating oil to reduce air pollution from this source. This White Paper evaluates the benefits, costs and implementation issues associated with reducing sulfur in #2 distillate heating oil from its current average of 2,000 to 3,000 parts per million (ppm) to 500 ppm. The states' long-term goal is to bring the sulfur content of heating oil into line with the future highway and nonroad ultra-low sulfur diesel fuel requirement of 15 ppm.

Heating oil burners emit particulate matter (PM), oxides of nitrogen (NO_x), sulfur dioxide (SO_2), mercury (Hg), carbon dioxide (CO_2) and other pollutants. Collectively, these pollutants have direct health impacts, contribute to the formation of ozone and fine particulate matter, cause regional haze, contribute to acid deposition and nitrification of water bodies, add to the global mercury pool and contribute to the build up of greenhouse gasses in the atmosphere. The combustion of heating oil is a significant source of SO_2 emissions in the region – second only to electric power plants. The burning of heating oil also produces approximately 10 percent of total CO_2 emissions in the Northeast.

As shown in Table ES-1, reducing the sulfur content of heating oil from 2,500 ppm to 500 ppm lowers SO_2 emissions by 75 percent, PM emissions by 80 percent, NO_x emissions by 10 percent, and CO_2 emissions by 1 to 2 percent. Other benefits associated with lowering the sulfur content of heating oil include heating system efficiency improvements, the opportunity to develop and market advanced high efficiency boiler and furnace technologies, and harmonizing with European and Canadian fuel standards.

Table ES-1: Emission Benefits of Low Sulfur Heating Oil and Biodiesel Blends (% reduction compared to 2,500 ppm sulfur fuel)

Pollutant	**Reduction with 500 ppm Sulfur Heating Oil**	**Reduction with 500 ppm Sulfur Heating Oil/Biodiesel Blend (80/20)**
SO2	75 %	84 %
PM	80 %	>80 %[1]
NOx	10 %	20 %
Hg	n/a	20 %[2]
CO2	1 % - 2%	17-18 %

[1] Additional PM reductions are expected with biodiesel blends, but no known test data exists to substantiate this assumption.

[2] Value based on the assumption that biodiesel contains no mercury. No known test data exist to substantiate this assumption

These benefits can be achieved at an overall savings to heating oil marketers and consumers. The incremental cost of low sulfur (500 ppm) heating oil compared to the higher sulfur product varies over time, but historically has averaged about 1.5 cents per gallon. Lower sulfur heating oil is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating equipment and can permit longer time intervals between vacuum cleanings, if existing service practices are converted from annual to "as needed" cleaning. The potential savings for oil heated homes due to reduced maintenance costs is on the order of hundreds of million of dollars a year on a national basis. The cleaning cost savings generated by using lower sulfur fuel oil is two to three times higher than the added fuel cost based on historic price differences between heating oil and highway diesel.

Biofuels, including soy-based biodiesel, contain negligible amounts of sulfur and nitrogen and can be blended with low sulfur heating oil to further reduce air emissions, improve the environmental attractiveness of home heating oil and extend supplies with renewable domestic feedstocks. Low sulfur (500 ppm) heating oil blended with a 20 percent soy-based biodiesel can reduce SO_2 emissions by 84 percent, PM emissions by greater than 80 percent, NO_x emissions by 20 percent, mercury emissions by 20 percent and carbon dioxide emissions by approximately 16 percent compared to 2,500 ppm sulfur heating oil.

The region's heating oil comes from Gulf Coast refiners, Northeast refiners, and foreign sources. Imports provide about a 20 percent of demand on an annual average basis, but can rise significantly during periods of peak usage. The continued availability of adequate home heating oil through domestic sources and imports is an important consideration as states assess implementation issues associated with a low sulfur oil heating oil initiative. This White Paper discusses a variety of steps that should be taken to ensure that a low sulfur heating oil program in the Northeast would not adversely affect supply and cost during periods of peak demand. Potential solutions include: (1) increasing stocks of lower sulfur fuel oil; (2) increasing imports from countries with lower sulfur standards; (3) permitting seasonal averaging of sulfur levels; (4) blending of lower sulfur diesel with higher sulfur imports; and (5) introducing greater amounts of domestic biofuels into the market.

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

1. INTRODUCTION AND BACKGROUND

1.1. Introduction

The combustion of heating oil containing sulfur levels on the order of 2,500 parts per million (ppm) contributes to ambient concentrations of fine particles found in the Northeast. These particles have adverse health and environmental impacts. The Northeastern U.S. is one of the world's largest markets for heating oil. In the eight state NESCAUM region (CT, ME, MA, NH, HJ, NY, RI and VT), approximately 4 billion gallons of heating oil are burned annually in residential furnaces and approximately 1 billion gallons are burned in commercial furnaces. Heating oil represents 54 percent of total demand for #2 distillate oil in the Northeast, compared to 38 percent for highway diesel.

Due to the high level of sulfur currently found in heating oil, its combustion is a significant source of sulfur dioxide (SO_2) emissions in the region – second only to electric power plants. Regionally, the burning of high sulfur heating oil generates approximately 100,000 tons of SO_2 annually – an amount equivalent to the emissions from two average sized coal-burning power plants. Oil heating is also a source of particulate matter (PM), oxides of nitrogen (NO_x) and carbon monoxide (CO). While data are limited and uncertain, residential heating with fuel oil is estimated to produce almost 25 percent of mercury emissions in the six New England states. The burning of heating oil also produces approximately 10 percent of total CO_2 emissions in the region and is estimated to represent as much as 17 percent of Connecticut's CO_2 inventory.

To address this concern, the Northeast states are considering adopting regionally consistent standards to cap the sulfur content of heating oil at 500 parts per million, by no later than 2010. The states' long-term goal is to limit the sulfur content of heating oil to levels consistent with future ultra-low sulfur diesel standards for highway and nonroad fuels (15 ppm). However, more research and development is needed to prevent the undesired impacts on home heating equipment that have been experienced in Europe with ultra-low sulfur fuel including damage to oil burner air tubes in blue flame oil burners.

This analysis is intended to help states better understand the benefits and costs associated with the proposed regional low sulfur heating oil initiative. While this analysis is preliminary in nature, it provides state regulators with additional information as they consider appropriate next steps.

This White Paper includes six sections. Section 1 provides background information on the oil heat market, the environmental and public health impacts associated with emissions from this source, and a summary of the proposed Northeast low sulfur heating oil initiative. Section 2 summarizes the emission reduction potential of lowering the sulfur content of heating oil and evaluates the potential benefits of adding biodiesel to heating oil. Section 3 summarizes the findings of the cost-benefit analysis undertaken for low sulfur heating oil. Section 4 discusses other benefits of this proposed initiative. Section 5 provides a brief overview of supply and distribution issues for the Northeast heating oil market. Section 6 presents conclusions.

1.2. Background

Lowering the sulfur content in heating oil will significantly reduce the threats to public health and sensitive ecosystems posed by SO_2 emissions in the Northeast. Emissions of NO_x, which contribute to a number of public health and environmental problems in the Northeast, will also decrease with lower sulfur heating oil. The use of cleaner fuel has the potential to improve furnace efficiency by reducing fouling rates of boiler and furnace heat exchangers and other components. Further, the availability of low sulfur heating oil will enable the introduction of highly efficient condensing furnace technology. Both outcomes will lower emissions of CO_2 and other pollutants from this source sector by reducing fuel use.

The region's heating oil comes from Gulf Coast refiners, Northeast refiners, and foreign sources. Imports provide about a 20 percent of demand on an annual average basis, but can rise significantly during periods of peak usage. The ability to bring in offshore product is important to heating oil availability and price stability. European supplies range from 13 percent on an annual average to 23 percent during January and February, with Russia supplying as much as 18 percent of the region's total demand during peak periods, based on recent reports.

Oil heat industry representatives have expressed concern that offshore suppliers will not have sufficient low sulfur product available for the North American market in the near to mid-term which will undermine the delicate supply balance that now exists. Industry representatives suggest that it will take a broader international shift toward low sulfur heating oil to drive offshore refiners to invest in de-sulfurization technology for this portion of the product stream. Europe, a major market for heating oil, will require low sulfur (1000 ppm) product beginning in 2008 and Canada is committed to a similar requirement. To minimize supply concerns, the Northeast states are considering an annual averaging compliance program that would allow higher sulfur product into the market during peak demand periods, if necessary. Further, as discussed in this paper, the blending of biodiesel into heating oil provides an additional stream of clean and renewable domestic feedstock to increase the supply of fuel for space heating. However, biofuels supplies are currently rather limited.

1.3. Public Health and Environmental Impacts

The Northeast states are faced with developing state implementation plans (SIPs) to demonstrate compliance with the new 8-hour ozone and fine particulate matter national ambient air quality standards. The states must also submit plans that include strategies for protecting visibility in national parks and wilderness areas. After three decades of controlling air pollution, the challenges of achieving sufficient additional emission reductions to attain these new standards are substantial.

Heating oil burners emit significant levels of SO_X, NO_x, PM, and mercury. These burners also emit CO_2, a greenhouse gas that contributes to global warming. Collectively, these pollutants have direct health impacts, contribute to the formation of ozone and fine particulate matter, cause regional haze, contribute to acid deposition and nitrification of water bodies, add to the global mercury pool and contribute to the buildup of greenhouse gases in the atmosphere.

1.3.1. Particulate Matter

Both solid particles and condensable liquid droplets are generated from most combustion sources including heating oil burners. Most of the particulate matter emitted by combustion sources is classified as fine PM with diameters less than 2.5 microns ($PM_{2.5}$). Primary particulates include unburned carbonaceous materials (soot) that are directly emitted into the air. Secondary particulates, such as sulfates, are formed after sulfur dioxide is emitted into the air from combustion sources burning sulfur-containing fuels. Particulate matter less than 10 microns in size (PM_{10}) is linked to a number of adverse health outcomes including asthma, bronchitis, cardiac arrhythmia, and heart attacks (reference 9). Sulfates are also the primary cause of regional haze and acid deposition in the Northeast.

Direct PM emissions from residential and small commercial oil burners in the form of soot have decreased by approximately 95 percent over the past three decades (as will be discussed later in this section). Sulfates that condense in the outdoor air after being emitted by oil heating equipment are now the predominate form of PM associated with emissions from heating oil burners. Reducing the sulfur content of the fuel can lower sulfate emissions.

1.3.2. Oxides of Nitrogen

NO_x is emitted during all types of fuel combustion. Nitrogen dioxide (NO_2) and the secondary oxidants that are formed in the atmosphere contribute to numerous adverse health outcomes. NO_2 causes respiratory distress, respiratory infection, and irreversible lung damage. These are exacerbated by the secondary oxidants that are produced including ozone and fine particulate matter. In addition these oxidants contribute to the formation of acid rain and regional haze.

Efficiency advances in residential oil heat equipment have included the introduction of flame retention oil burners that produce higher flame temperatures and enhanced heat transfer rates. These improvements have helped decrease PM emissions, however, the resultant elevated flame temperatures contribute to increased rates of nitric oxide production by oil burners (thermal NO_x). On the positive side, the higher emission rates are offset by the improved efficiency and reduced fuel use. New oil burners are currently under development in the U.S. that lower nitrogen oxide emissions substantially. The use of lower sulfur home heating oil also lowers the emissions of nitrogen oxide by reducing the nitrogen content of the fuel that contributes to total NO_x emissions.

1.3.3. Sulfur Dioxide

SO_2 is a criteria air pollutant produced in significant quantities by residential and commercial oil heat burners. Elevated levels of SO_2 in the atmosphere can cause wheezing, breathing difficulty, and shortness of breath. Through its important role in fine particulate matter formation, SO_2 also contributes to cardiovascular disease, respiratory illness, and impaired lung function especially in individuals with pulmonary diseases including asthma. Sulfur dioxide also contributes to acid rain and related crop and vegetation damage. Sulfates are the primary cause of regional haze in the Eastern U.S.

Burning home heating oil with lower sulfur content directly reduces SO_2 emissions and its negative impact on health and the environment.

1.3.4. Mercury

Mercury is a potent neurotoxin, particularly damaging to the fetus and young child. Greater than 84,000 newborns in the Northeast are at risk for irreversible neurological deficits from exposure to mercury. Emerging data also suggest a link between mercury exposure and increased risk of adverse cardiovascular effects. The Northeast is implementing a Mercury Action Plan that has reduced total in-region emissions by greater than 55 percent over the past five years. Much of this reduction has come from emission controls put on municipal waste combustors and medical waste incinerators. With emissions from these major stationary sources better controlled, the combustion of fuel oil in residential and commercial burners is now considered a major source of mercury emissions in the region.

1.4. Proposed Northeast Low Sulfur Heating Oil Initiative

The Northeast states are considering adopting consistent low sulfur heating oil requirements as part of the larger plan to address the region's air pollution problems. The decision to pursue a consistent regional strategy is premised on the Northeast's common airshed and the regional nature of the heating oil supply network. In order to achieve reductions in SO_2 emissions from home oil burners, a regional low sulfur initiative is proposed for the states in the Northeast where oil is a predominant energy source. This initiative is summarized in a *DRAFT Memorandum of Understanding for Regional Fuel Sulfur Content Standards for Distillate Number 2 Heating Oil* dated February 4, 2005 (reference 7). The memorandum proposes a reduction in the sulfur content of distillate fuel oil used for space heating from the typical range of 2000 to 3000 part per million (ppm) down to 500 ppm, as now required for highway diesel fuel. The sulfur content of highway diesel will be lowered to 15 ppm beginning in 2006.

Homeowners and fuel oil service companies will benefit from reduced fouling of boiler and furnace heat transfer surfaces that permits extended intervals between vacuum cleanings. This has the potential to substantially lower annual service costs for oil heating equipment. Nationwide, this translates to potential cleaning cost savings on the order of \$200 million to \$300 million a year; with much of this benefit accruing in the Northeast. As discussed in more detail in Section 3, the added cost for the cleaner fuel is expected to be more than offset by the savings resulting from reduced maintenance and improved burner efficiency. The oil heat industry also benefits when the environmental impact of heating oil is reduced since it makes this product more competitive with natural gas as clean energy source for space heating.

As shown in Table 1-1 (reference 7), current sulfur requirements for home heating oil vary widely from state to state in the Northeast. The proposed limit on the sulfur content of distillate oil used for commercial and residential heating would establish a uniform standard across all states in the region at 500 parts per million.

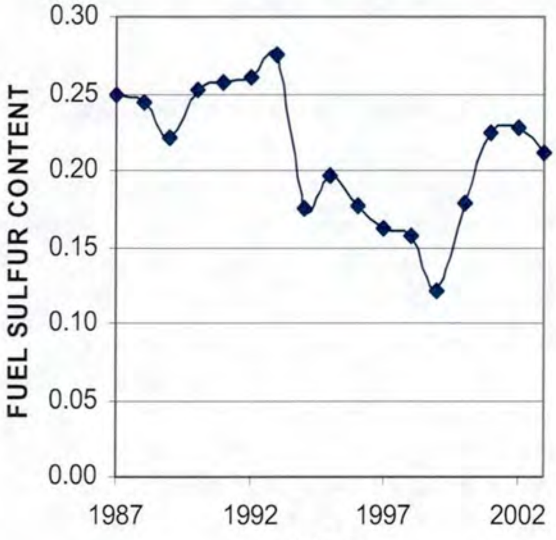
Table 1-1: State Sulfur Limits for Heating Oil

State	Sulfur Limit In percent	Sulfur Limit In parts per million
Connecticut	0.3	3000
Maine	0.3 to 0.5	3000 to 5000
Massachusetts	0.3	3000
New Hampshire	0.4	4000
New Jersey	0.2 to 0.3	2000 to 3000
New York Upstate	1.0 to 1.5	10,000 to 15,000
New York Downstate	0.2 to 0.37	2000 to 3700
Rhode Island	0.5	5000
Vermont	2.0	20,000

1.5. Current Fuel Sulfur Content of Heating Oil

According to sampling conducted over the past two decades, the average sulfur content of heating oil varies from year to year (see Figure 1-1). These data are reported in *Heating Oils, 2003* published by Northrop Grumman Mission Systems (reference 8). Historically, the sulfur content of home heating oil was in the range of 0.25 percent or 2500 ppm. After lower sulfur diesel (500 ppm) was introduced for highway use, the average sulfur content of home heating oil decreased.

Figure 1-1: #2 Fuel Oil Sulfur Content Percentage (REF: NGMS – 231)



From 1987 to 1993, the average sulfur content of heating oil remained at approximately 0.25 percent. Between 1993 and 1999, the percentage of sulfur decreased steadily within the 1200 to 2000 ppm range. For the period 1999 to 2002, the average sulfur content has increased, returning to historic levels. From 2002 to 2003 the average sulfur content was 0.22 percent. These results are based on relatively small sample sizes, however, and the actual average sulfur content of oil used in homes in the Northeast has not been accurately determined.

1.6. Fuel Sulfur Requirements in Other Countries

Lower sulfur heating oil is gaining acceptance around the world including in Canada and Europe. The sulfur content of distillate oil in EU countries will be limited to 0.1 percent or 1000 ppm by January 1, 2008, based on Directive 1999/32/ EC (reference 19). The average sulfur content of light heating oil in Canada from 1995 to 2001 was between 2000 ppm and 2700 ppm, with an average of 2010 ppm in 2001 (reference 19), which is similar to sulfur levels in the U.S. The Minister of Environment in Canada has indicated an intention to reduce sulfur levels in fuel oil to improve public health and the environment with the goal of matching the sulfur requirement set by the European Union (EU) for 2008.

A presentation by the Institute for Wirtschaftliche Oelheizung, dated September 17, 2003, listed the current fuel sulfur standards for Europe in percent: Austria 0.005 to 0.1; Belgium 0.2 or less; France 0.2 or less; Germany 0.005 to 0.2; Great Britain 0.2 or less; Italy 0.2 or less; Sweden 0.1 or less; Switzerland 0.2 or less (reference 20). This presentation also showed a decreasing trend in sulfur content with Switzerland moving toward 50 ppm to 500 ppm sulfur, and Scandinavia, Germany, Austria and Belgium moving toward 50 ppm sulfur fuel limits.

Switzerland has an allowable limit for sulfur content of 0.2 percent, but taxes fuel oil higher than 0.1 percent. Reportedly, most of the fuel sold had sulfur content of 0.1 percent or lower. There are low sulfur fuels with 0.03 to 0.05 percent sulfur on the market in Europe and its use is reported to represent up to 20 percent of the fuel sold in Germany.

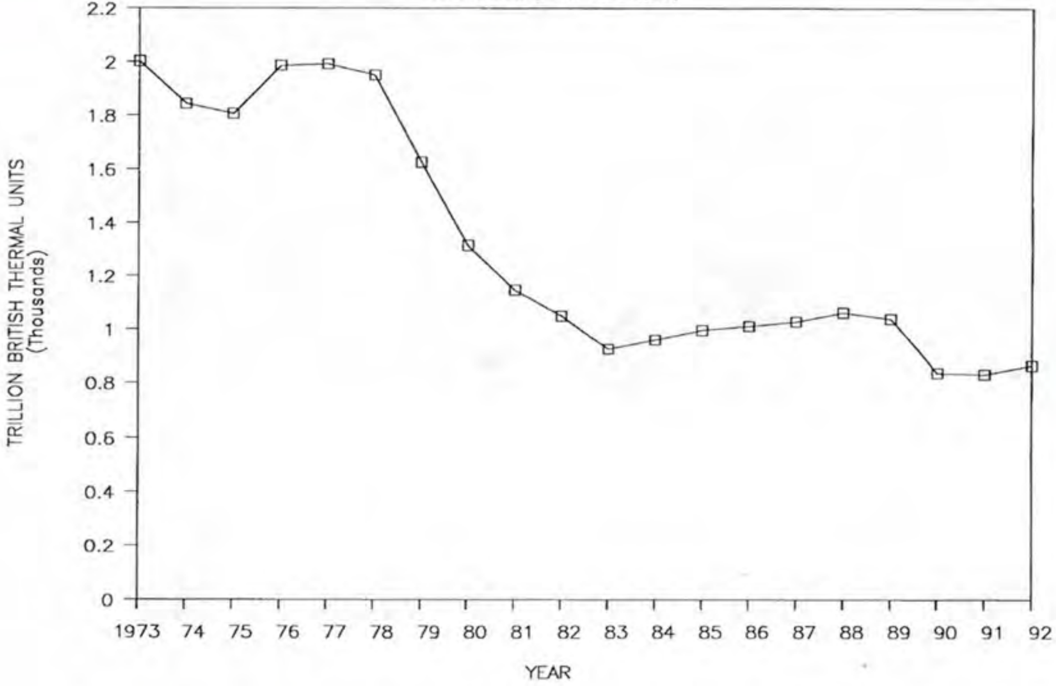
1.7. Past Advances in Oil Heat Emissions Performance

Important advances have occurred over the past three decades that have helped to reduce air emissions from residential oil heating equipment through the efforts of oil heat marketers and equipment manufacturers. These include voluntary energy conservation initiatives that have lowered fuel use and technology advances that have substantially lowered the emission rate for particulate matter from oil burners.

Prior to 1973 and the first substantial oil price increases, oil heated homes typically consumed 1400 gallons of fuel annually. Efforts by the oil heat research program at Brookhaven National Laboratory and the oil heat equipment manufacturers resulted in the development of more efficient equipment that contributed to a decrease in oil consumption by the average house to less than 900 gallons a year. The plot that follows, based on data published by the Energy Information Administration (U.S. Department of Energy), shows a 40 percent reduction in fuel use from the mid 1970s to the present time. Between 1977 and 1992 residential annual fuel oil use decreased from 1,994 to 865 trillion BTU. The number of oil heated homes fell by about 25 percent, and energy efficiency improvement is credited with lowering fuel use by approximately 40 percent (references 1,2). The annual residential consumption of distillate fuel oil averaged 861 trillion BTU from 1995 through 1999.

Figure 1-2: U.S. Annual Residential Fuel Oil Use

REF: USDOE/EIA-0214(92)

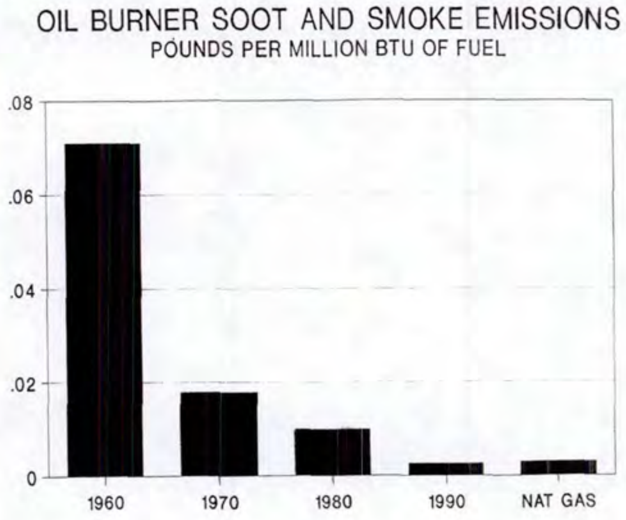


In addition to energy conservation programs, the historical reduction in fuel oil use has been spurred by the development and use of new higher efficiency oil heating equipment. The flame retention oil burner, which increases fuel efficiency by about 15 percent, was developed through industry-sponsored research and development efforts and began to dominate the market in the late 1970s (reference 3). The efficiency of new oil-powered boilers and furnaces also increased substantially from the late-1970s to the present with average annual fuel utilization efficiencies rising from less than 70 percent (estimated) to more than 85 percent.

The increases in oil burner, boiler, and furnace efficiencies directly contributed to the 40 percent reduction in average annual fuel consumption. Annual emissions of air pollutants including PM, SO_x, NO_x, and CO_2 have also decreased by 40 percent as a direct result of the reduction in annual fuel consumption in homes. In fact, calculations indicate that from 1977 to 1992, greenhouse gases from oil heat were lowered by 470 million tons (reference 1).

Particulate matter emissions from oil burners have been lowered by more than 95 percent over the past three decades as a result of the development and deployment of the flame retention oil burner. In addition to increasing efficiency and lowering fuel use, the rate of PM emissions is much lower with the flame retention design. The plot that follows shows the reduction in the rate of PM emissions by oil burners over the past 30 years (reference 4).

Figure 1-3: Reductions in Oil Burner PM Emissions



BASED ON DATA FROM USEPA AND BNL

The rate of filterable particulate emissions decreased by a factor of 20 from the 1960s to the 1990s as oil burner design evolved and fuel-air mixing improved as a result of increased air supply pressure. Enhanced fuel-air mixing produces more complete combustion and lowers PM (smoke and soot) emissions. These substantial reductions in PM emissions from residential oil burners were recognized by the U.S. Environmental Protection Agency in the mid 1990s when the standard emissions factor for oil burners was lowered by a factor of seven to 0.003 pounds of PM per million BTU of fuel burned during cyclic operation (references 4, 5). Properly adjusted oil burners now produce particulate mater emissions that are similar to natural gas burners.

While the oil heat industry has compiled an impressive record of energy conservation and lowered air emissions over the past several decades, the high sulfur content of the fuel used for space heating continues to represent a significant source of SO_2. These emissions can be lowered dramatically through the introduction of lower sulfur heating oil as will be discussed in the next section.

Given the nature of this source (i.e., millions of individual units), there are fewer options for reducing air pollution from residential and commercial heating units than large industrial source. Since traditional regulatory measures, such as the addition of emission control technology to existing facilities, are not practical for this sector, the use of cleaner fuel represents the best near-term option for controlling emissions from oil burners.

2. EMISSION REDUCTION POTENTIALS OF LOW SULFUR HEATING OIL AND BIOFUELS

This section summarizes the emission reduction potential associated with the use of lower sulfur home heating oil for SO_2, NO_x, PM and CO_2. Additionally, the potential environmental benefits that could be achieved by blending biofuels into low sulfur heating oil are discussed.

2.1. Low Sulfur (500 ppm) Home Heating Oil

As described earlier, the introduction of lower sulfur heating oil can reduce emissions of several key air pollutants. Table 2-1 shows typical emission rates for residential oil burners using fuel with sulfur contents of 500 and 2500 parts per million, based on emission factors published by the U.S. Environmental Protection Agency (references 1,5).

Table 2-1: Air Emission Rates for Home Oil Burners

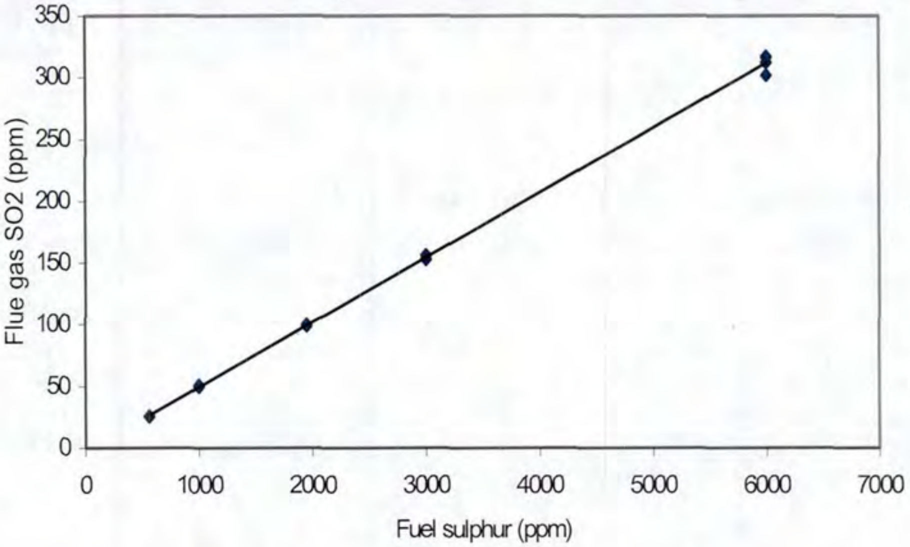
Pollutant	**Emission Rate In lbs/MMBTU**
PM Total	0.012
PM Condensable	0.0094
PM Filterable	0.0030
CO	0.036
TOC / VOC (non methane)	0.0051
NOx	0.13
SOx 0.05%	0.05
SOx 0.25%	0.26

Reference: *Oil Burner Emissions: AP-42 Sept 98 (Jan 2004)*

2.1.1. Sulfur Dioxide Emissions

The SO_2 emission rate for home heating oil with 0.25 percent (2500 ppm) sulfur is 0.26 pounds per Million BTU of fuel burned. Using oil containing 0.05 percent sulfur (500 ppm) lowers the sulfur oxide emissions to 0.05 pounds per million BTU. Figure 1-1 indicates that typical sulfur contents of distillate fuel oil are currently in the 0.22 percent range. The graph in Figure 2-1 shows the change in SO_2 emissions as the sulfur content of heating oil changes (reference 10). SO_2 emissions from home oil burners are directly related to the sulfur content of the fuel. Reducing the sulfur content of heating oil from an average of 0.20 percent to 0.05 percent lowers the rate of sulfur oxide emissions by 75 percent. If the fuel sulfur content is lowered by 80 percent, the sulfur dioxide emissions decrease by 80 percent.

Figure 2-1: Relationship of Fuel Sulfur Content to SO_2 Emissions

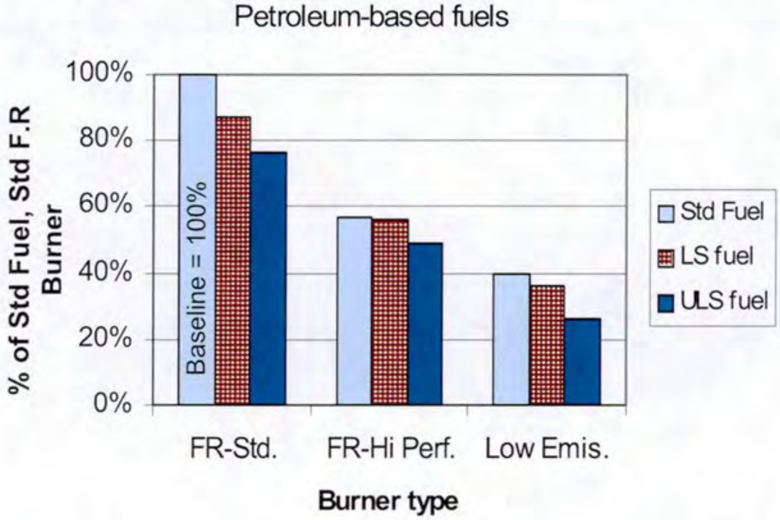


2.1.2. Nitrogen Oxide Reductions:

Figure 2-2 shows measured reductions in NO_x emissions associated with using lower sulfur heating oil for several oil burner types (reference 11). The chart shows the measured reduction in nitrogen oxide emissions for three oil burner designs and three fuel sulfur contents. "FR-Std" refers to a standard flame retention oil burner, "FR-Hi Perf" is a new high performance flame retention oil burner, and "LowEmis" refers to a new generation of low NO_x oil burners. The three test fuels were: standard fuel oil (nominally 2100 ppm S), low sulfur fuel at 250 ppm (LS), and an ultra low sulfur fuel oil (ULS) at 91 ppm. For each burner type, as the fuel sulfur content decreased, the NO_x emission rate also dropped. The standard flame retention oil burner produced 10 percent lower NOx emissions when the 500 ppm sulfur fuel was used in place of normal sulfur (2000 ppm) fuel. These tests clearly demonstrate that NO_x emissions from residential heating systems decrease when low sulfur heating oil is burned. Further, these test data point to the additional NO_x reductions that could be realized by reducing heating sulfur below 500 ppm.

For a standard flame retention oil burner, the most common burner type now used in homes, the lower sulfur heating reduced NO_x emissions by about 12 percent. However, the test fuel contained 250 ppm of sulfur, so the expected NO_x reduction for a 500 ppm fuel would be slightly less. The expected reduction in nitrogen oxide emissions from conventional flame retention oil burners is in the range of 10 percent when conventional heating oil (>2000 ppm sulfur) is replaced with 500 ppm sulfur oil. These reductions can be achieved by changing only the fuel properties, without any burner modifications.

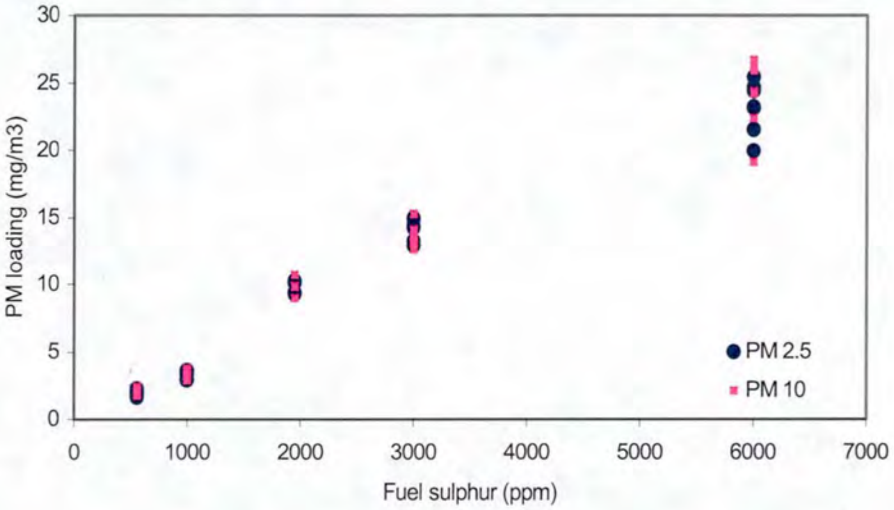
Figure 2-2: Nitrogen Oxide Emission Reductions with Lower Sulfur Heating Oil



2.1.3. Particulate Matter (PM) Reductions:

Figure 2-3 relates PM emissions (filterable and condensable) from home oil burners to fuel sulfur content (reference 10). The x-axis shows the fuel sulfur content of heating oil in parts per million and the y-axis shows the total loading in milligrams per cubic meter of exhaust for both PM_{10} and $PM_{2.5}$. There is a linear relationship between total PM loading and fuel sulfur content: as the sulfur content of fuel decreases, the PM loading decreases proportionally. These data indicate that lowering the sulfur content of the fuel from 2500 ppm to 500 ppm reduces total PM emissions by a factor of five, and lowering the sulfur content from 2000 ppm to 500 ppm reduces PM emissions by a factor of four. PM emissions from oil burners using low sulfur heating oil approach the particulate emissions of natural gas burners which are widely recognized as one of the cleanest combustion sources.

Figure 2-3: Effect of fuel sulfur on $PM_{2.5}$ and PM_{10} emissions



2.2. Low Sulfur (500 ppm) Heating Oil Blended with Biofuels

Low sulfur heating oil can be blended with biofuels to further reduce air emissions, improve the environmental attractiveness of home heating oil and extend supplies with domestic feedstocks. Biofuels, including soy-based biodiesel, contain negligible amounts of sulfur and nitrogen and can further lower SO_2 and NO_x emissions from oilheat burners. In addition, smoke and soot emissions from biofuel blends are less than for petroleum-based distillate oil. Biodiesel is not known to contain mercury. Greenhouse gas emissions are also lowered as the feedstocks for biofuels are re-grown and sequester carbon from the air.

Lower sulfur heating oil blended with biofuels represents a premium fuel with excellent combustion characteristics and lower air emission rates than conventional petroleum-based distillate heating oil. In fact, low sulfur (500 ppm) heating oil combined with a 20 percent soy-based biodiesel has comparable environmental characteristics to natural gas (reference 12).

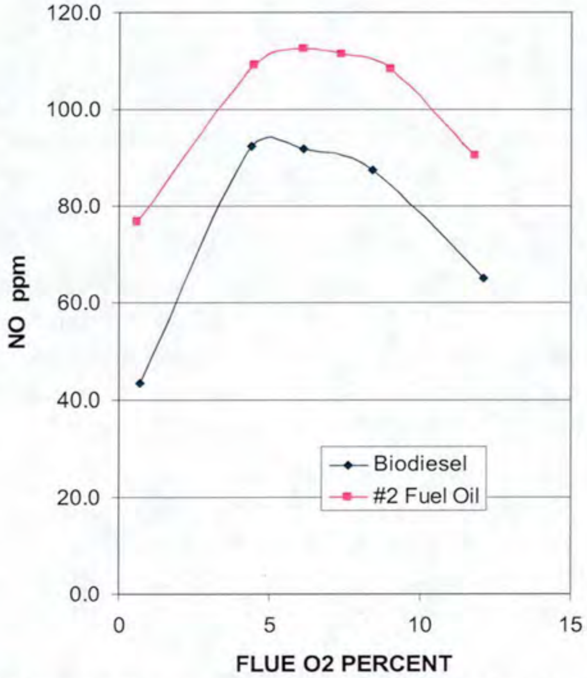
2.2.1. Sulfur Dioxide Reductions

Tests of sulfur dioxide emissions with a blend of 80 percent heating oil containing 500 ppm sulfur and 20 percent soy-based biodiesel were conducted for the Massachusetts Oilheat Council at the New England Fuel Institute in 2003 (reference 13). Because the sulfur content of biofuels is near zero, adding 20 percent biodiesel lowers the fuel sulfur content of the final blend. The measured reduction in SO_2 emissions was 84 percent compared to the normal sulfur distillate fuel used for these tests. Compared to a 2000 ppm base fuel, an 80 percent reduction in SO_2 emissions is expected for a blend of 80 percent low sulfur (500 ppm) distillate fuel and 20 percent biofuel. This is greater than the 75 percent reduction expected when 500 ppm sulfur fuel oil replaces 2000 ppm sulfur fuel.

2.2.2. Nitrogen Oxide Reductions:

Nitrogen Oxide emissions are significantly lower for the 20 percent biofuel blend in 500 ppm fuel oil compared to the reductions achieved with lower sulfur fuel alone. In fact, typical measured NO_x reductions for the biofuel blend were double those for the 500 ppm sulfur heating oil. In one case, for a boiler with an atypically high combustion chamber temperature, the NO_x levels did not decrease for the biofuel/low sulfur blend. The figure below shows the results of a typical test.

Figure 2-4: Nitric Oxide Emissions for Low Sulfur / Biofuel Blend



Note: *NO ppm (at 3% excess air) versus FLUE O_2 %; Unit 13, 0.75 gph*

Figure 2-4 shows measured flue gas emissions of Nitric Oxide (NO) as the burner excess air is varied and the flue gas oxygen content increases. These data are corrected to 3 percent excess air. The biofuel/low sulfur oil blend emits much less NO than conventional higher sulfur home heating oil. These preliminary tests suggest that about one-half of the reduction is produced by the lower sulfur fuel oil and the other half is produced by the biofuel. The lower sulfur fuel oil and biofuel blends can substantially reduce NO_x emissions without requiring burner or boiler modifications.

2.2.3. Particulate Matter Reductions:

Lower sulfur content in heating oil reduces PM emissions and biofuels can lower these emissions even further. Combustion test results showed that biofuel blends lower smoke emissions. In one test program, a burner was adjusted for zero smoke using the blend of biofuel and low sulfur oil. When the conventional (higher sulfur) home heating oil was used at the some burner air setting, the smoke level increased from zero to a number 3 on the Bacharach (ASTM 2156) scale. While these tests cannot measure actual PM loading, it is clear that the biofuel blend lowers smoke and soot emissions.

2.2.4. Mercury Reductions

While there is a paucity of data, it is expected that adding biodiesel to heating oil will reduce Hg emissions by an amount equivalent to the blend percentage. Soy-based biofuel is not known to contain mercury and therefore will dilute the mercury concentration of the final fuel when blended with petroleum-based heating oil. Additional testing is needed to more accurately quantify the emission coming from residential and commercial oil heating and to verify the relationship between the addition of biodiesel and changes in mercury emissions from the combustion of the blended fuel. Further, the relationship between the sulfur and mercury content of distillate is not well understood. The Northeast states will begin a testing program in 2006 to measure both the sulfur and mercury content of heating oil and highway diesel in an effort to better quantify mercury content and the potential relationship between sulfur and mercury concentrations in distillate.

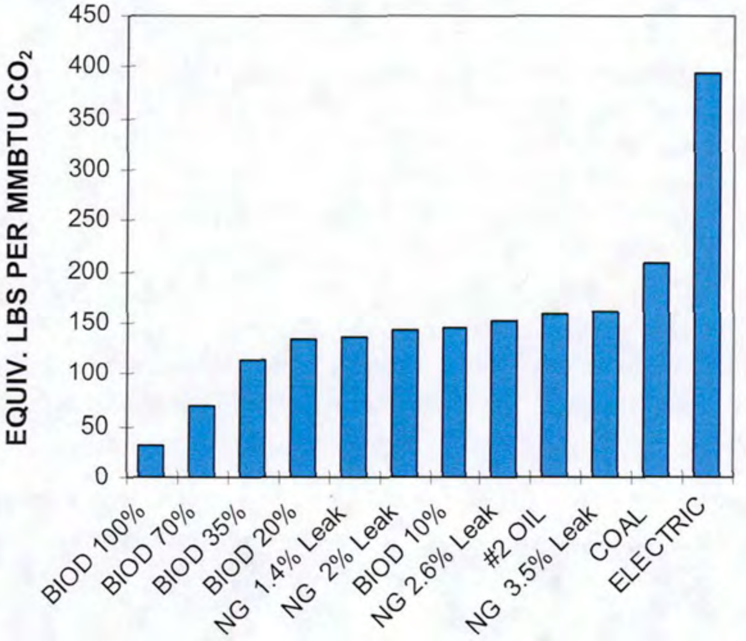
2.2.5. Greenhouse Gas Emission Reductions:

An additional benefit of biodiesel blends is that the biofuel component is re-grown which removes carbon dioxide from the atmosphere. While some energy is required to re-grow and process the soy-based biodiesel, research indicates a net reduction in greenhouse gases of 80 percent for soy-based biofuels. This means that a 20 percent soy biodiesel blend will lower carbon dioxide emissions by approximately 16 percent.

The chart in Figure 2-5 shows the net global warming impact potentials for a range of fuels including fuel oil with varying percentages of soy biodiesel. Values are in pounds per million BTU of fuel burned, and are based on emission factors published by the U.S. Environmental Protection Agency (reference 5).

"Biod 100%" is heating oil consisting of 100 percent soy-based biodiesel fuel. The next three values shown are biodiesel fuels at 70 percent, 35 percent, and 20 percent respectively. "NG 1.4% Leak" is for natural gas including a gas leakage rate during transmission and distribution of 1.4 percent of throughput, and an average methane-to-CO_2 global warming ratio of 30. "NG 2% Leak" is for natural gas including a gas leakage rate of 2.0 percent of throughput. "Biod 10%" is heating oil consisting of 10 percent biodiesel fuel. "NG 2.6% Leak" is for natural gas including a gas leakage rate of 2.6 percent. "Number 2 oil" shows emissions for standard distillate heating oil used in homes. Coal emissions are higher because of the higher carbon-to-hydrogen ratio. Electric energy has the highest greenhouse gas emissions based on U.S. Department of Energy Publications showing total CO_2 emissions and total energy generated.

Figure 2-5: Global Warming Potentials of Various Energy Sources



Note: *Equivalent CO_2 Emissions Pounds Per Million BTU for Oil and Natural Gas (Ref: USEPA AP-42)*

The lowest global warming potentials for all fuels are the biodiesel-heating oil blends. The 100 percent biodiesel blend (B100) produces the lowest global warming potential. The B20 blend is lower than all other sources including natural gas. For the 10 percent biodiesel in petroleum-based heating oil, the total global warming potential is lower than for natural gas within the range of expected gas leakage rates.

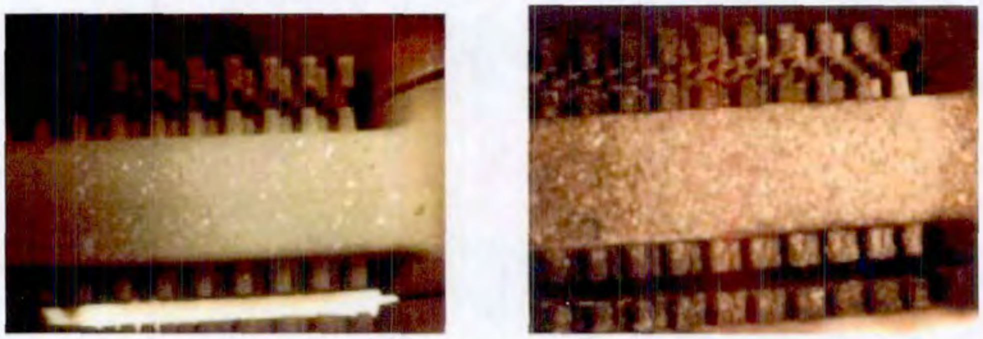
One important factor in comparing the climate impacts of natural gas and heating oil is methane leakage that occurs during natural gas transmission and distribution given the higher global warming potential of methane compared to carbon dioxide. Because biofuel are renewables, when blended with home heating oil, they reduce the global warming potential below that of natural gas.

3. COST-BENEFIT ANALYSES OF LOW SULFUR HOME HEATING OIL

Lower sulfur heating oil is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating equipment and permits longer time intervals between vacuum cleanings. The potential costs savings for oil heated homes due to reduced maintenance is on the order of hundreds of million of dollars a year, most of which accrues in the Northeast and Mid-Atlantic states where oil is a dominant fuel for space heating. The added cost for the lower sulfur fuel is expected to be less than the savings produced by cleaner operation.

Figure 3-1 shows the impact of various fuel oil sulfur contents on the rate of fouling depositions inside a residential cast iron boiler based on research conducted by Brookhaven National Laboratory. These photos clearly show that more boiler fouling occurs as the sulfur content of the fuel increases. The reduced rate of deposits with lower sulfur fuel oil lowers cleaning costs.

Figure 3-1: Boiler Fouling for Varying Fuel Oil Sulfur Contents



No 2 heating fuel, 0.04% Sulfur by weight

No. 2 heating fuel, 0.18% Sulfur by weight

No 2 heating fuel, 0.34% Sulfur by weight

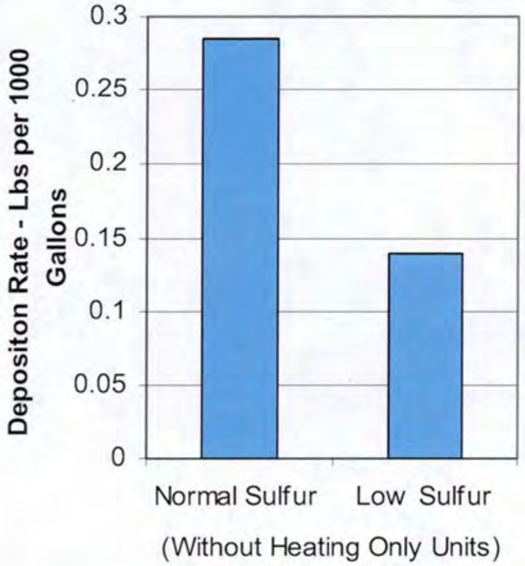
No. 2 heating fuel, 1.08% Sulfur by weight

The lower sulfur fuel produces minimal boiler deposits as shown in the upper left photograph for the 0.04 percent sulfur fuel (reference 10).

3.1. Reduced Maintenance Costs

Figure 3-2 summarizes the results of a comprehensive field study of the impacts of low sulfur fuel oil (0.05 percent) funded by the New York State Energy Research and Development Authority (NYSERDA). See Reference 10 for details of this multi-year study. Boiler deposits were collected and analyzed for houses burning normal sulfur and low sulfur heating oil. The results showed a significant reduction in boiler deposits for the low sulfur houses, consistent with the laboratory tests conducted by Brookhaven National Laboratory and in Canada on boiler deposition rates.

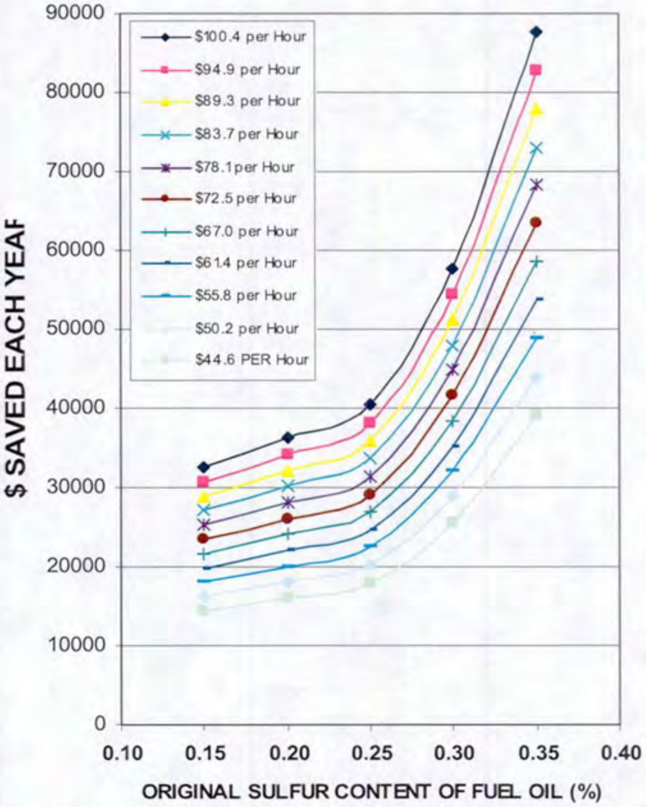
Figure 3-2: Measured Boiler Deposits – Normal and Low Sulfur Fuel Oil



Boiler deposits were reduced by a factor of two by lowering the fuel sulfur content from 0.14 percent to 0.05 percent for the houses in the study. Larger reductions in boiler depositions are produced when the initial sulfur content is higher. These reduced deposits translate into much lower costs for vacuum cleaning by extending the service interval. When the existing heating oil sulfur content is 2000 to 2500 ppm and 500 ppm sulfur fuel is substituted, the service interval can be extended by a factor of three or more (e.g., cleaning at three year intervals rather than annually). This produces substantial savings in service costs for oil-heated homes.

The reduced boiler and furnace fouling rates achieved by using lower sulfur fuel oil translate directly into lower vacuum-cleaning costs for fuel oil companies and homeowners. The chart that follows summarizes expected savings for a range of hourly service rates and for varying initial fuel oil sulfur percentages (reference 10).

Figure 3-3: Vacuum Cost Savings per 1000 Houses



Note: *The cost savings in dollars per year, by using 0.05% Sulfur Fuel Oil per 1,000 customers*

For example, at a median hourly service cost of $72.50 and an initial fuel sulfur content of 0.25 percent (2500 ppm), the expected reduction in vacuum cleaning costs is $29,000 a year per 1000 houses. If the hourly service rates are higher, the annual savings are also higher. The service rates shown here are for illustrative purposes, actual costs may be higher than the maximum values or lower than the minimum values shown on the graph.

The potential vacuum-cleaning cost savings for the U.S., for a starting fuel sulfur content of 0.20 percent, ranges from approximately $200 million a year to $390 million a year for service costs of $50 to $100 per hour. Therefore, if all oil heated homes switched to 500 ppm sulfur heating oil, more than $200 million a year could be saved, which would significantly lower the overall operating costs of fuel oil marketers (reference 10). Given the dominant share of the U.S. heating oil market represented by the Northeast states, a large percentage of the projected national benefits would accrue in the region.

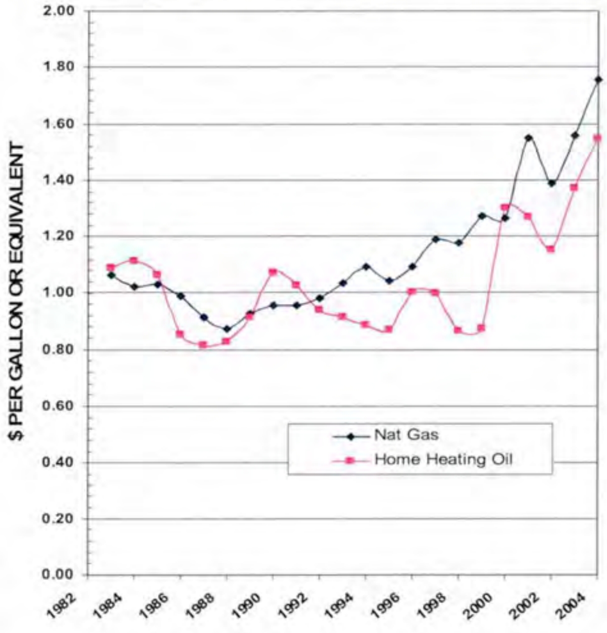
3.2. Added Cost for Lower Sulfur Heating Oil and Historic Fuel Prices

The incremental cost of low sulfur (500 ppm) home heating oil compared to the higher sulfur product varies over time. Fuel oil prices reported in the *Weekly Petroleum Status Report* published by the U.S. Department of Energy (reference 15) were used to compare New York Harbor spot market prices of # 2 heating oil and # 2 diesel (low sulfur). From January 2003 through March 2004, the price of the low sulfur diesel ranged from $ 0.0022 per gallon to $ 0.0378 per gallon higher than the price of the higher sulfur heating oil. The average price increment for the lower sulfur product was 1.6 cents per gallon for the 15 month period examined.

Data collected by the Oilheat Manufacturers Association, which tracks fuel oil and natural gas prices, shows that the retail price of home heating oil has cycled up and down over the past twenty years (reference 16). Figure 3-4 shows dollar per gallon equivalent prices for heating oil and natural gas between 1982 and 2004.

Figure 3-4: Home Heating Oil and Nat Gas Prices

(CT, ME, MA, NH, RI, VT, DE, MD, NJ, NY, PA, DC, VA)



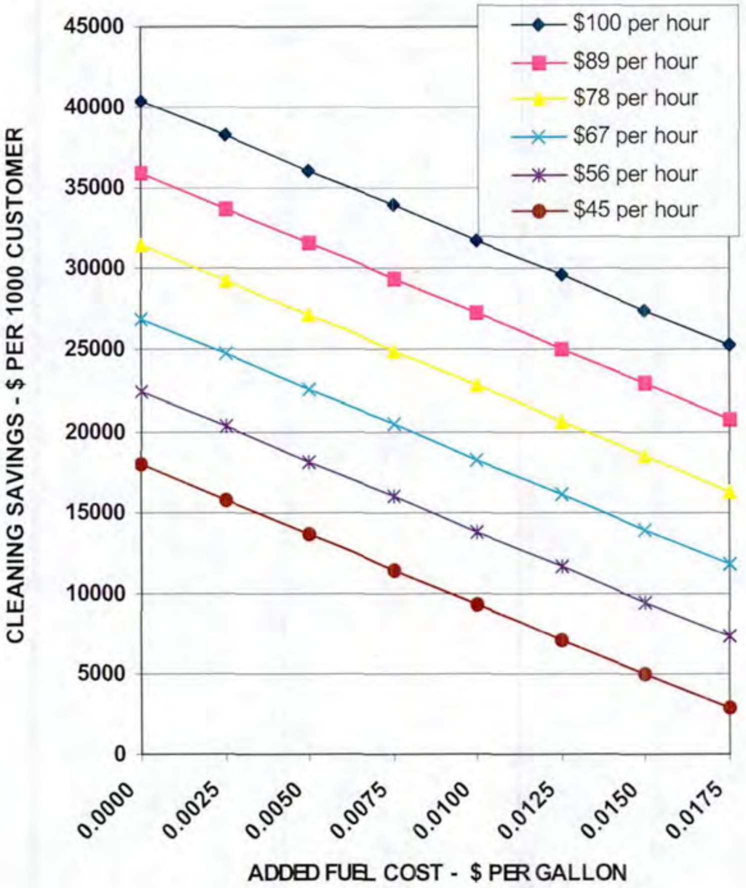
Residential oil prices have increased and decreased over this period. From 1984 to 1988 oil prices fell about 27 percent, and then increased from 1984 to 1991 by about the same amount. This represents a cyclical change of more than 25 percent. From 2001 to 2002 average oil prices increased by more than 50 percent, and then decreased for the next two years.

The added cost of low sulfur heating oil is on the order of 1.6 cents per gallon; representing approximately 1 percent of the average oil price. The incremental cost of low sulfur heating oil is much smaller than historical oil price fluctuations. Therefore, the added cost for lower sulfur heating oil is expected to have a minimal overall economic impact on home heating oil consumers.

3.3. Net Cost Savings with Lower Sulfur Fuel Oil

The chart in Figure 3-5 presents the net cost savings of lower sulfur heating oil including the effect of added fuel costs (reference 10). The net savings are shown for a range of added fuel costs and for various hourly service rates. For an added cost of low sulfur home heating oil of 1.5 cents per gallon, and for an hourly service rate of $78 per hour, the net cost savings by reduced vacuum cleaning intervals is $18,000 or about $18 per customer. This chart can be used to estimate the net savings associated with the use of lower sulfur home heating oil for a range of fuel and maintenance costs.

Figure 3-5: Net Cost savings per 1,000 Houses Using Low Sulfur Oil
For: 0.25%S (initial) and 865 Gal per Year



The cleaning cost savings generated by using lower sulfur fuel oil are greater than the added cost of the fuel. The NYSERDA study indicates that the expected savings in vacuum cleaning costs is approximately two to three times higher than the added fuel cost for service rates of $75 to $100 per hour. Other reductions in service costs, in addition to the vacuum cleaning cost savings, were also observed during NYSERDA's multi-year field demonstration of low sulfur home heating oil (reference 10). This further improves the benefit to cost ratio for lower sulfur fuel oil.

3.4. Environmental and Health Benefits

In addition to the cost savings that would accrue to oil heat marketers and consumers due to reduced maintenance, substantial public health and environmental benefits would be realized through the introduction of low sulfur heating oil. According to the NYSERDA study referenced earlier, the potential reductions in SO_2 emissions by using 500 ppm sulfur oil to replace 2000 ppm sulfur is approximately 60,000 tons per year nationwide. These emission reductions occur primarily in the Northeast where a majority of the home heating oil is consumed. In New York State alone, the projected SO_2 reductions associated with the shift to low sulfur home heating oil is about 13,000 tons per year (reference 10).

In summary, this section suggests that lower sulfur fuel oil and lower sulfur/biofuel blends can provide important public health and environmental benefits in a very cost-effective manner. In fact, the cost savings due to reduced need for heating system cleaning and maintenance alone more than offset the incremental cost of the lower sulfur fuel. When the public health and environmental benefits are added to the equation, a 500 ppm sulfur heating oil program represents one of the most cost-effective air pollution control strategies available to the Northeast states. The next section discusses other benefits associated with the introduction of lower sulfur heating oil.

4. OTHER BENEFITS OF LOW SULFUR HEATING OIL

Additional benefits derived from the use of heating oil with lower sulfur content include efficiency improvements, the opportunity to develop and market advanced boiler and furnace technologies, and harmonizing with European and Canadian fuel standards.

4.1. Improved Efficiency

Lower sulfur fuel oil produces less fouling of the heat transfer surfaces inside boilers and furnaces as discussed earlier. This helps improve the long-term efficiency of the boiler or furnace by maintaining high heat transfer rates from the hot flame gases to the boiler water or furnace warm air. Research conducted by Brookhaven National Laboratory indicates that the drop in heating equipment efficiency is on the order of one or two percent each year, with higher decreases in some cases. After the heating unit is cleaned, the thermal efficiency returns to the higher levels. Therefore, using lower sulfur home heating oil can improve the efficiency of oil heating equipment on the order of one to two percent.

The added benefits of improved efficiency are two-fold. First, heating costs are reduced, as less fuel is required to supply the required heating demand. Second, the emissions of all pollutants are reduced, as less fuel is consumed by more efficient boilers and furnaces. On an individual basis this is a small increment. However, when applied to the more than 10 million home heating systems in the U.S., the reductions in fuel use and air emissions are meaningful.

4.2. Opportunity to Utilize Advanced Equipment

Part of the energy loss from heating equipment is in the form of water vapor in the exhaust gases. Each pound of water vapor removes 970 BTUs, which represents about 6.5 percent of the energy content of the fuel oil. Brookhaven National Laboratory conducted research in the 1980's on developing "condensing" furnaces and boilers that operate at very low exhaust temperatures that permit some of the water vapor heat loss to be recovered. One problem with heating oil is that the fuel sulfur content increases the acidity of the condensed water vapor. This requires measures to protect the heat transfer surfaces from acid attack and damage. Recently, the National Oilheat Research Alliance funded the development of oil-powered condensing heating equipment and the availability of lower sulfur heating oil will support expanded use of this new technology.

The use of lower (500 ppm) and eventually ultra low sulfur (15 ppm) heating oil offers the opportunity to improve boiler and furnace designs to include flue gas condensation and increase efficiencies into the mid to upper 90 percent range. This is comparable to the highest efficiencies now available from natural gas-powered equipment.

Historically, condensing oil furnaces have been available. However, design and maintenance problems associated with the use of higher sulfur heating oil limited widespread use of condensing oil equipment. The availability of lower sulfur oil can lower equipment and service costs and permit expanded use of higher efficiency warm air oil furnaces and hot water boilers. This is an important option for oil heat consumers as both oil and natural gas prices continue to rise. Higher efficiency equipment can help assure that oil heat remains an economically viable option for residential consumers to maintain a mix of fuels needed for energy diversity. The use of this higher efficiency equipment will reduce the emissions of all air pollutants, including CO_2, as less fuel is needed to produce the same heat output. Market demand for condensing furnaces is likely to increase as prices for heating oil rise.

4.3. Harmonizing with Worldwide Standards

Clearly, the trend in Europe, Canada and elsewhere is toward lower sulfur heating oil. Home heating oil sulfur contents are being lowered to 0.1 percent or 1000 ppm in the near-term with a target of 500 ppm to 50 ppm in many European countries and other nations around the world as reviewed earlier. The U.S. can keep pace with these changes and encourage fuel refiners and suppliers toward lower sulfur products by joining with other nations in requiring lower sulfur oil. Joining forces with other major fuel users around the world will help to move sulfur standards to lower levels so that the many benefits of the lower sulfur product that are summarized in this report can be realized as soon as possible. Reducing the number of products transported and stored around the world by harmonizing sulfur limits is the most expeditious way to achieve the goal of lower sulfur fuel oil.

5. OVERVIEW OF SUPPLY AND DISTRIBUTION OF HEATING OIL IN THE NORTHEAST

The continued availability of adequate supplies of heating oil from domestic sources and imports is an important consideration in assessing the costs and benefits of establishing low sulfur standards. This section presents a brief overview of some key issues and potential strategies that will enable the use of lower sulfur home heating oil in the U.S. in the near-term without significant supply disruptions or price spikes.

In April 2005, total petroleum use in the U.S. was 20.4 million barrels per day (MMBPD) of which 13.2 MMBPD was from imports (reference 21). Imports accounted for approximately 65 percent or almost two-thirds of the total petroleum products in the U.S. supplied for domestic uses. In contrast, the percentage of distillate fuel imported into the U.S. is much smaller. Table 5-1 is based on data related to distillate fuel oil supply from reference 21.

Table 5-1: US Distillate Fuel Oil Supply (Thousand Barrels per Day)

Year	Refiner Output	Imports	% Imports
2002	3,592	267	7.4
2003	3,707	333	9.0
2004	3,819	320	8.4
2005	3,627	384	10.5 (Jan to April 2005)

Distillate fuel use in the U.S. is less than 20 percent of total petroleum use. The percentage of distillate fuel oil imported to U.S. from 2002 to 2005 ranged from 7.4 to 10.5 percent. This does not include exports of distillate fuel oil that ranged from 87 to 112 thousand barrels per day, or changes in stocks. The percentage of imported fuel is considerably higher in the Northeast where the majority of the nation's heating oil is consumed, especially during periods of peak demand.

Nationally, residential distillate fuel oil consumption is only a small percentage of total U.S. distillate use, ranging from 10.7 to 11.4 percent of the total from 1999 to 2003 (reference 22). Residential consumption represents less than two percent of total U.S. petroleum use. Highway diesel fuel consumption is five times higher than that of residential distillate, ranging from 55.5 to 58 percent of total U.S. distillate demand for the same time period. However, the situation in the Northeast is dramatically different where heating oil represents 54 percent of total demand for #2 distillate oil, compared to 38 percent for highway diesel.

Distillate fuel oil is brought into the Northeast from a combination of sources that include a pipeline that runs from the Gulf States to New Jersey, refineries in New Jersey and Pennsylvania, imported fuel from Canada by trucks, and from other countries by tanker. Distillate imports come from three main sources: Canada, the Virgin Islands, and Venezuela with a combine volume of 196 thousand barrels per day for the peak year from 2000 to 2003. These three countries provide about two-thirds of total distillate imports to the Northeast on an annual average basis (reference 23).

An important consideration regarding a requirement for lower sulfur heating oil is the availability of lower sulfur distillate fuel imports during times of peak fuel consumption, in January and February when the outdoor temperature is the coldest. A presentation by Allegro Energy Consulting on August 23, 2004 (reference 23) compared the annual percentage of imported distillate fuel oil (high sulfur) in the Northeast to the percentage of total demand met by domestic refiners. Table 5-2 summarizes this information.

Table 5-2: Source of Annual Distillate Fuel Oil Supplies on the East Coast (%)

Year	East Coast Refineries	Golf Coast Receipts	Imports
2000	39%	36%	**24%**
2001	33%	38%	**29%**
2002	37%	37%	**26%**
2003	34%	37%	**29%**

The annual percentage of high sulfur distillate oil imports used for heating ranged from 24 to 29 percent from 2000 to 2003. This is higher than the national average for all distillate fuel oil that ranged from 7.4 to 10.5 percent. The percentage of imports to the East Coast during the first quarter of the years 2000 to 2003 when the peak demand occurs are shown in Table 5-3 (Reference 23).

Table 5-3: Peak Distillate Fuel Oil Imports (%)

Year	To East Coast
2000	30%
2001	41%
2002	24%
2003	39%

These data indicate a significant year-to-year fluctuation in wintertime demand met by imports. In 2002, imports accounted for 24 percent of peak quarter demand, which is similar to the average annual East Coast values. By contrast, 41 percent of peak demand was met by imports in 2001. The peak volume of imported distillate fuel oil to the East Coast, approximately 400 thousand BPD, occurred during the first quarter of 2001. It is important to note that distillate stocks were not available to meet the peak demand in 2001, as it was in subsequent years, which caused imports to increase.

The Allegro presentation indicates that about two-thirds of distillate imports to the Northeast during the peak year come from Canada, the Virgin Islands, and Venezuela that supply 74, 71, and 51 thousand BPD of distillate fuel, respectively. The next largest suppliers of imported fuel have been: Europe at 31 TBPD; Russia at 28 TBPD; Africa at 14 TBPD; and Asia, South America, Caribbean, Middle East, and Mexico for a total of 27 TBPD. Concern has been expressed regarding the ability of offshore marketers to supply lower sulfur distillates fuel as needed to meet peak demand in the near-term. Russia and Africa are two historic suppliers that are not expected to lower sulfur content of their distillate fuels in the near-term. However, together, they supplied only about 14 percent of imports during the peak year examined. It seems likely that other suppliers will be able to make up the difference. However, during episodic cold spells, the demand for imports can be significantly higher than the first quarter averages discussed above.

Based on the concern expressed by industry representatives about potential near-term adverse supply impacts associated with a low sulfur heating oil requirement, the Northeast states are assessing potential strategies for ensuring needed supplies during peak heating demand periods. These include: (1) increasing pre-season stocks of lower sulfur fuel oil; (2) increasing imports from countries with lower sulfur standards; (3) permitting seasonal averaging of sulfur levels; (4) blending of lower sulfur distillate with higher sulfur imports; and (5) introducing greater amounts of domestic biofuels into the market over time.

The Irving presentation (reference 24) indicates that during peak heating demand, in the 2001 to 2004 period, heating oil stocks helped supply the needed fuel. Fuel stocks supplied approximately 200 thousand BPD for that time period. This limited the amount of imports during periods of peak demand between 2002 and 2004. The exception was in 2001, when adequate distillate stocks were not available, and the peak demand for imports increased to about 400 thousand BPD. Therefore, building adequate stocks of distillate fuel at the start of the heating season is an important mechanism for lowering reliance on imports.

Some sources of imported distillate oil may not be able to supply the lower sulfur fuel oil in the near-term, but other sources are expected to have low sulfur product available. For example, European countries are leading the way with 0.1percent sulfur oil required in 2008. Canada plans to meet the EU target, and other nations are also expected to meet the lower sulfur mandates. Small increases in imports from some of the larger suppliers who will produce reduced sulfur fuel can compensate for the countries that lag in sulfur reduction.

Seasonal averaging would diminish supply constraints by allowing providers to bring in "non-specification" fuel during periods of peak demand as long as the higher sulfur gallons are offset by lower sulfur fuel over the course of the heating season. The objective is to have an average seasonal or yearly fuel delivery that meets the new sulfur limit. This provision permits flexibility when fuel supplies are tight and fuel marketers must rely more on imports to meet the heating demand.

Fuel blending is another approach for meeting lower fuel sulfur standards. The ultra-low sulfur (ULS) or 15 ppm standard for highway use is approaching and diesel fuel with very low sulfur content will be widely available. If this lower sulfur product is added to a higher sulfur stock, the average sulfur content drops rapidly. For example, a blend of 80 percent fuel with 500 ppm sulfur and 20 percent 15 ppm fuel produces an average sulfur content of 403 ppm. This fuel blending method can be used to comply with lower sulfur standards for heating oil. It is important to remember that in the U.S., diesel production and fuel use is approximately five times higher than home heating oil use. Therefore, if all home heating oil was blended with 20 percent ULS diesel, it would require only about 4 percent of the diesel supply. In reality, much less than 4 percent of the ULS diesel supply would be needed, given the other compliance methods available.

The supply of imported fuel oil is strongly dependent on the fuel price differential. Historically, the volume of net imports increases as the price of heating oil increases on spot markets. After October 1989, the heating oil spot market price increased by 5 to 10 cents per gallon and the volume of imports doubled from less than 250 to 500 thousand BPD. A similar increase in imports occurred after October 2002. Even increases of 5 cents per gallon have historically produced substantial increases in the rate of distillate fuel imports. Higher fuel oil prices for the lower sulfur product must be minimized so that the balance between oil, natural gas and other energy sources is not disrupted. The strong relationship between distillate import rates and changes in fuel prices suggests that imports could help offset temporary fuel shortages during times of peak demand.

Many environmental, public health, and equipment service cost benefits are produced by using lower sulfur home heating oil. The use of lower sulfur distillate heating oil is gaining acceptance, with Europe, Canada and other nations leading the way, much as the U.S. led the way for lower sulfur diesel fuel. An immediate question is how much can the sulfur limits be lowered without disturbing normal fuel supplies around the world. The good news is that distillate heating oil in the U.S. represents a much smaller fraction of the barrel than diesel fuel use whose sulfur content has already been reduced to 500 ppm and is slated to go to 15 ppm beginning in 2006. The challenge is to develop a plan for implementing lower sulfur heating oil standards that will minimize supply problems in the Northeast especially during times of peak heating demand in January and February.

6. CONCLUSIONS

The Northeast states are in the process of developing long-term strategies to meet national ambient air quality standards and visibility goals and regional targets for mercury and greenhouse gas reductions. As part of the planning effort, a wide range of pollution control strategies are being evaluated. Residential and commercial space heating with fuel oil has been identified as an important source of emissions. Given the relative lack of regulation of this sector, the implementation of lower sulfur fuel standards appears to represent a cost-effective emission reduction option.

The emissions from residential and commercial oil heating contribute to ozone and particulate matter formation, mercury deposition and the build up of greenhouse gasses in the atmosphere. Given the impracticality of applying source-by-source emission control technology, the best option for reducing emissions from fuel oil heaters is the introduction of cleaner-burning fuel.

SO_2 emission reductions of 75 percent can be achieved by lowering the sulfur content of heating oil from current levels to 500 ppm. A ten percent reduction in NO_x emissions from this source sector can also be achieved. The benefits of this approach are realized immediately upon introduction of the cleaner fuel and therefore can help states meet specific near to mid-term emission reduction targets.

The Northeast states are also evaluating the merits of blending biofuels with lower sulfur heating oil to improve the emission characteristics and open up the market for domestically produced clean-burning renewable fuels. Blending twenty percent biodiesel with 80 percent 500 ppm sulfur #2 distillate further lowers SO_2 and PM emissions compared to 500 ppm sulfur heating oil and doubles the NO_x benefits. The addition of twenty percent soy-based biodiesel also lowers greenhouse gas emissions by almost twenty percent and through dilution, reduces average mercury concentrations in the emission stream.

The significant emission reductions associated with the introduction of lower sulfur heating oil standards can be achieved in a cost-effective manner. The incremental cost of 500 ppm highway diesel fuel has averaged 1.5 cents per gallon more than heating oil over the past decade. Further, the use of lower sulfur heating oil reduces the fouling of heating oil equipment and consequently extends maintenance intervals. Assuming that maintenance is needed only every third year, rather than annually, the cleaning cost savings are projected to be two to three times greater than the added fuel cost. With the recent increase in fuel oil cost, the 1.5 cent per gallon increment is a smaller percentage of total heating oil cost.

The volatile nature of heating supply and demand presents unique challenges to the fuel oil industry. The success of a low sulfur fuel oil program is predicated on meeting these challenges. The Northeast states are assessing a variety of business strategies and regulatory approaches that could be used to minimize any potential adverse supply and price impacts that could result from a regional 500 ppm sulfur standard for heating oil. Suppliers can increase pre-season reserves and look to increase imports from offshore refiners producing low sulfur product. Blending domestically produced biodiesel into heating oil offers opportunity to reduce imports, stabilize supplies and minimize supply-related price spikes. Air quality regulators are also considering permitting seasonal averaging of sulfur content which would allow higher sulfur imports to be brought to the Northeast market during periods of peak demand. Over the course of the year, the higher sulfur fuel would have to be offset by heating oil with a sulfur content below the standard.

The analysis summarized in this White Paper supports the Northeast states conclusion that significant reductions in SO_2, NO_x, PM and CO_2 emissions can be achieved by mandating lower sulfur heating oil. Importantly, these reductions can achieved at an overall savings to the consumer. Adding the public health and environmental benefits of a lower sulfur fuel further substantiate the favorable cost-benefit ratio of a regional 500 ppm sulfur heating fuel program.

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