9. Modeling

Air quality modeling to assess regional haze has been done cooperatively by the MANE-VU member states, with major modeling efforts being conducted by NESCAUM[28] and screening modeling being conducted by the New Hampshire Department of Environmental Services (NHDES)[29]. These modeling efforts include emissions processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 and several future periods, including the 2018 primary target period for this SIP. Modeling was conducted in order to assess contribution from upwind areas, as well as Maine's contribution to its own Class I areas. Further, the modeling evaluated visibility benefits of control measures being considered for achieving reasonable progress goals and establishing a long-term emissions management strategy for MANE-VU Class I areas. The modeling tools utilized for these analyses include the following:

- The Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5) was used to derive the required meteorological inputs for the air quality simulations.
- The Sparse Matrix Operator Kernel Emissions (SMOKE) emissions modeling system was used to process and format the emissions inventories for input into the air quality models.
- The Community Mesoscale Air Quality model (CMAQ) was used for the primary SIP modeling.
- The Regional Model for Aerosols and Deposition (REMSAD) was used during contribution apportionment.
- The California Grid Model (CALGRID) and its associated EMSPROC6 emissions processor was used to screen specific control strategies.

Each of these tools has been evaluated and found to perform adequately, and the SIP pertinent modeling underwent full performance testing and the results were found to meet the specifications of EPA modeling guidance.

For more details on the regional haze modeling, refer to the NESCAUM report "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment P). The detailed modeling approach for the most recent 2018 projected scenario can be found in the NESCAUM report "2018 Visibility Projections," May 13, 2008 (Attachment Q).

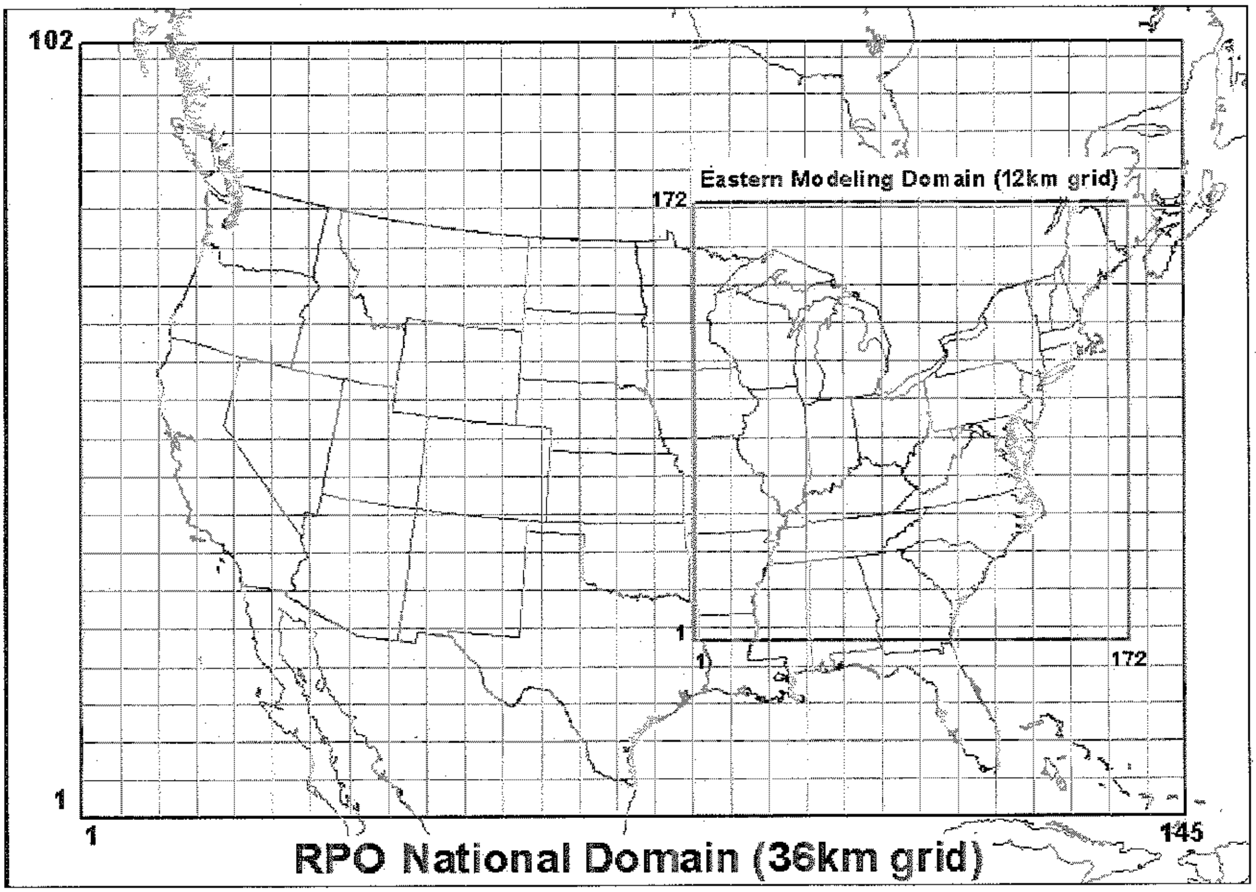
9.1 Meteorology

The meteorological inputs for the air quality simulations were developed by the University of Maryland (UMD) using the MM5 meteorological modeling system. Meteorological inputs were generated for 2002 to correspond with the baseline emissions

[28] Along with the NYSDEC, NJDEP/Rutgers, VADEQ, and UMD.
[29] Along with the VTDEP and MDEQ.

inventory and analysis year. The MM5 simulations were performed on a nested grid as illustrated in Figure 9-1. As shown in the figure, the modeling domain is comprised of a 36-km, 145 x 102 continental grid and a nested 12-km, 172 x 172 grid encompassing the

Figure 9-1
Modeling domains used in MANE-VU air quality modeling studies with CMAQ.
Outer (blue) domain grid is 36 km and inner (red) domain is 12 km grid
The gridlines are shown at 180 km intervals (5 × 5 36 km cells/15 × 15 12 km cells)



Eastern United States and parts of Canada. In cooperation with the New York State Department of Conservation (NYSDEC), an assessment was made to compare the MM5 predictions with observations from a variety of data sources, including:

- Surface observations from the National Weather Service and the Clean Air Status and Trends Network (CASTNet);
- Wind-profiler measurements from the Cooperative Agency Profilers (CAP) network;
- Satellite cloud image data from the UMD Department of Atmospheric and Oceanic Science; and
- Precipitation data from the Earth Observing Laboratory at NCAR. This assessment was performed for the period covering May through September 2002.

Further details regarding the MM5 meteorological processing and the modeling domain can be found in NYSDEC's technical support document TSD-1a, "Meteorological Modeling Using Penn State/NCAR 5th Generation Mesoscale Model (MM5)," February 1, 2006 (Attachment K), and in the NESCAUM report "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," November 27, 2007 (Attachment P).

9.2 Emissions Data Preparation

Emissions were prepared for input into the CMAQ and REMSAD air quality models using the SMOKE emissions modeling system. SMOKE supports point, area, mobile (both on-road and non-road), and biogenic emissions. The SMOKE emissions modeling system uses flexible processing to apply chemical speciation as well as temporal and spatial allocation to the emissions inventories. SMOKE incorporates the Biogenic Emission Inventory System (BEIS) and EPA's MOBILE6 motor vehicle emission factor model to process biogenic and on-road mobile emissions, respectively. Vector-matrix multiplication is used during the final processing step to merge the various emissions components into a single model-ready emissions file. Examples of processed emissions outputs are shown below in Figure 9-2.

Further details on the SMOKE processing conducted in support of the air quality simulations is provided in NYSDEC's technical support document TSD-1c, "Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations," September 19, 2006 (Attachment I), and in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment P). Additional details on the emissions inventory preparation can be found in Section 8.0 of this report.

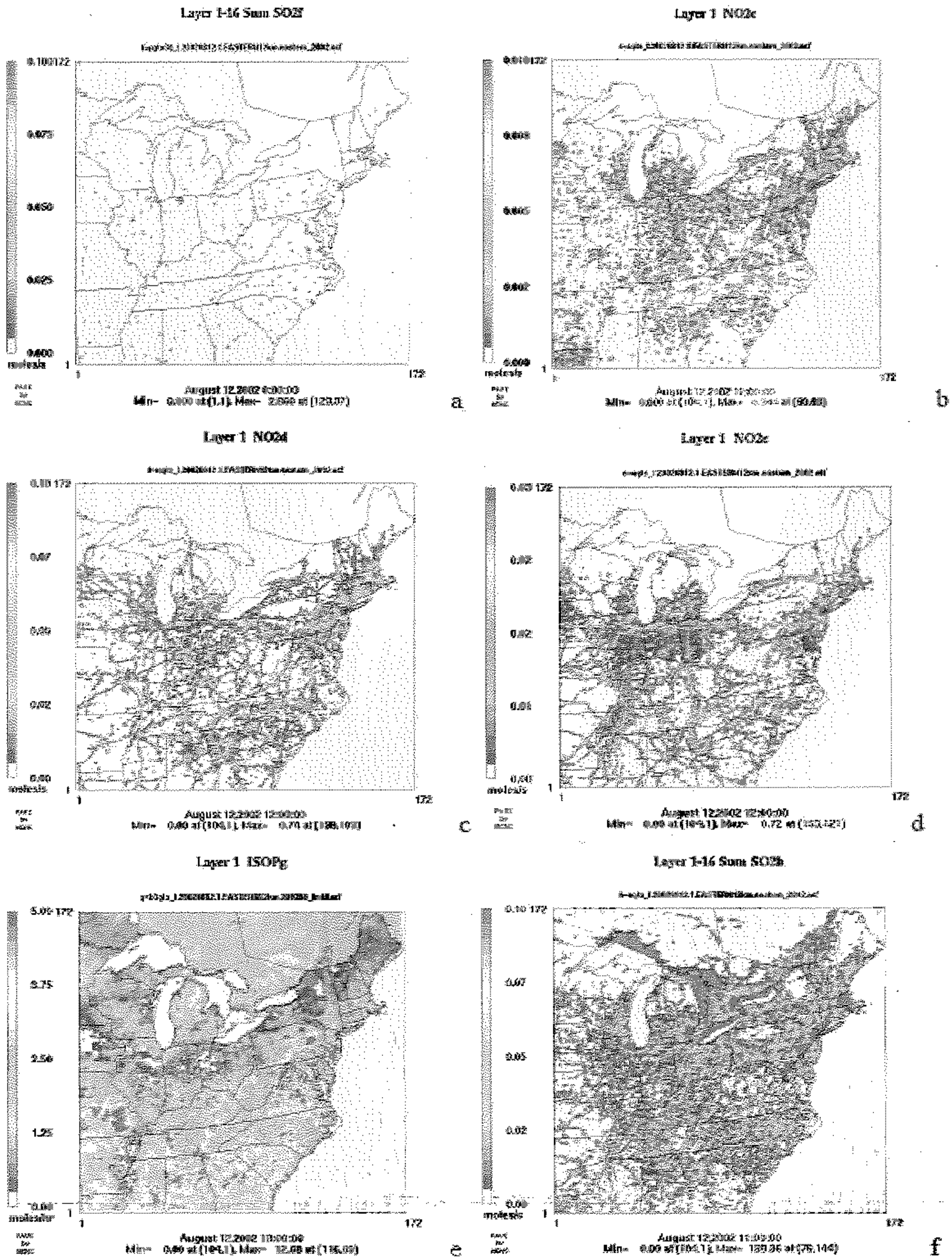
9.3 Primary Regional Haze Modeling Platforms

MANE-VU used two regional-scale air quality models to perform its primary air quality simulations. These are the Community Multi-scale Air Quality modeling system (CMAQ; Byun and Ching, 1999) and the Regional Modeling System for Aerosols and Deposition (REMSAD; SAI, 2002). CMAQ was developed by USEPA, while REMSAD was developed by ICF Consulting/Systems Applications International (ICF/SAI) with USEPA support. CMAQ has undergone extensive community development and peer review (Amar et al., 2005) and has been successfully used in a number of regional air quality studies (Bell and Ellis, 2003; Hogrefe et al., 2004; Jimenez and Baldasano, 2004; Mao and Talbot, 2003; Mebust et al., 2003). REMSAD has also has been peer reviewed (Seigneur et al., 1999) and used by USEPA for regulatory applications) to study ambient concentrations and deposition of sulfate and other PM species[30].

[30] www.epa.gov/otaq/regs/hd2007/frm/r00028.pdf and www.epa.gov/clearskies/air_quality_tech.html

Figure 9-2
Examples of Processed Model-Ready Emissions

(a) SO_2 from Point; (b) NO_2 from Area; (c) NO_2 from On-road; (d) NO_2 from Non-road; (e) ISOP from Biogenic; (f) SO_2 from all source categories



9.3.1 CMAQ

The CMAQ air quality simulations were performed cooperatively between five modeling centers, including NYSDEC, the New Jersey Department of Environmental Protection (NJDEP) in association with Rutgers University, the Virginia Department of Environmental Quality (VADEQ), UMD, and NESCAUM. NYSDEC also performed an annual 2002 CMAQ simulation on the 36-km domain shown in Figure 9-1; this simulation was used to derive the boundary conditions for the inner 12-km eastern modeling domain. Boundary conditions for the 36-km simulations were obtained from a run of the GEOS-Chem (Goddard Earth Observing System) global chemistry transport model that was performed by researchers at Harvard University.

The CMAQ modeling system is a three-dimensional Eulerian model that incorporates output fields from emissions and meteorological modeling systems and several other data sources through special interface processors into the CMAQ Chemical Transport Model (CCTM). The CCTM then performs chemical transport modeling for multiple pollutants on multiple scales. With this structure, CMAQ retains the flexibility to substitute other emissions processing systems and meteorological models. CMAQ is designed to provide an air quality modeling system with a "one atmosphere" capability containing state-of-science parameterizations of atmospheric processes affecting transport, transformation, and deposition of such pollutants as ozone, particulate matter, airborne toxics, and acidic and nutrient pollutant species (Byun and Ching, 1999).

MANE-VU SIP modeling on both 36 km and 12 km domains used CMAQv4.5.1, IOAPI V2.2 and NETCDF V3.5 libraries. The CMAQ model is configured with the Carbon Bond IV mechanism (Gery et al., 1989) using the EBI solver for gas phase chemistry rather than the SAPRC-99 mechanism due to better computing efficiency with no significant model performance differences for ozone and PM as compared to observations. NY DEC completed annual 2002 CMAQ modeling on the 36 km domain to provide dynamic boundary conditions for all simulations performed on the 12 km domain. Three-hourly boundary conditions for the outer domain were derived from an annual model run performed by researchers at Harvard University using the GEOSCHEM global chemistry transport model (Park et al., 2004). Model resolution was species dependent at either 4° latitude by 5° longitude or 2° by 2.5°.

Annual CMAQ modeling on the 12 km domain is divided into five periods. UMD was responsible for the period from January 1 to February 28; NJ DEP/Rutgers were responsible for the period from March 1 to May 14; NYSDEC was responsible for the period from May 15 to September 30; VADEQ was responsible for the period from October 1 to October 31; and NESCAUM was responsible for the period from November 1 to December 31. Each period uses a 15-day spin-up run to minimize the impact of the default initial concentration fields. Each modeling group performed CMAQ simulations on its period for a series of scenarios including 2002 Base Case, 2009 Base Case, 2018 Base Case, 2009 Control Case, and 2018 Control Case. All scenarios adopt the same meteorological field (2002) and boundary conditions, varying only emission inputs. To ensure consistency, a benchmark test was conducted by each modeling group.

In addition to the annual simulations conducted with CMAQ by the five modeling centers, NESCAUM conducted limited sensitivity analysis of several control measures using the beta version of CMAQ with the particle and precursor tagging methodology (CMAQ-PPTM) (ICF, 2006). The technical options that were used in performing the CMAQ simulations are described in detail in NYSDEC's technical support document TSD-1d, "8hr Ozone Modeling using the SMOKE/CMAQ system," February 1, 2006 (Attachment K). Further technical details regarding the CMAQ model and its execution are also provided in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment P).

9.3.2 REMSAD

The REMSAD modeling simulations were used to satisfy the haze rule requirement that a pollution apportionment be performed to assess contribution to visibility improvement by geographic region or source sector. REMSAD's species tagging capability makes it an important tool for this purpose. The Regional Modeling System for Aerosols and Deposition (REMSAD) is a three-dimensional Eulerian model designed to support a better understanding of the distributions, sources, and removal processes relevant to fine particles and other airborne pollutants. It calculates the concentrations of both inert and chemically reactive pollutants by simulating the physical and chemical processes in the atmosphere that affect pollutant concentrations. The basis for the model is the atmospheric diffusion equation representing a mass balance in which all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes are expressed in mathematical terms. The REMSAD model performs a four-step solution procedure: emissions, horizontal advection/diffusion, vertical advection/diffusion and deposition, and chemical transformations during one-half of each advective time step, and then reverses the order for the following half-time step. The maximum advective time step for stability is a function of the grid size and the maximum wind velocity or horizontal diffusion coefficient. Vertical diffusion is solved on fractions of the advective time step to keep their individual numerical schemes stable.

REMSAD uses a flexible horizontal and vertical coordinate system with nested grid capabilities and user-defined vertical layers. It accepts a geodetic (latitude/longitude) horizontal coordinate system or a Cartesian horizontal coordinate system measured in kilometers. REMSAD uses a simplified version of CB-IV chemistry mechanism that is based on a reduction in the number of different organic compound species and also includes radical-radical termination reactions. The organic portion of the chemistry is based on three primary organic compound species and one carbonyl species.

The model parameterizes aerosol chemistry and dynamics for PM and calculates secondary organic aerosol (SOA) yields from emitted hydrocarbons. REMSAD V7.12 and newer versions have capabilities that allow model tags of sulfur species (up to 11 tags), nitrogen (4 tags), mercury (up to 24 tags), and cadmium (up to 10 tags) to identify the impact of specific tagged species. Unlike CMAQ, REMSAD provides no choice of chemical and physical mechanisms. Due to the simplified chemistry mechanism, REMSAD may not simulate atmospheric processes as well as CMAQ. However, advantages such as the tagging feature for sulfur, more efficient modeling, and reasonable correspondence with measurements for many species, make REMSAD an important source apportionment tool for MANE-VU. The MANE-VU REMSAD modeling utilized the same 12 km eastern modeling domain shown in Figure 9-1, above. Multiple runs are necessary to permit tagging of sulfur emissions for all of the states in the domain, Canada, and the boundary conditions. NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008, further describes the REMSAD model and its application to the regional haze SIP efforts (See Attachment P).

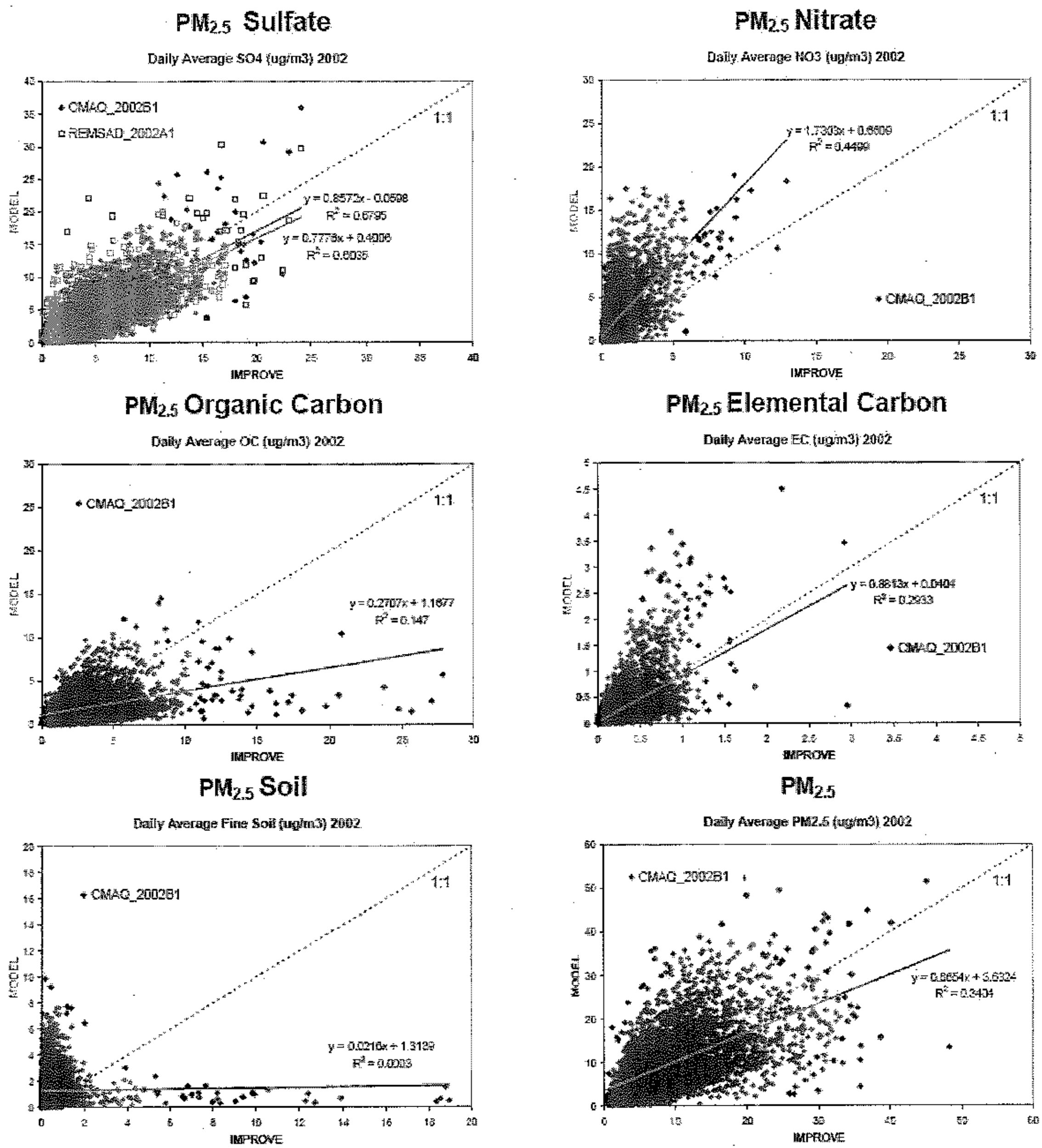
9.4 Primary Model Evaluation

9.4.1 CMAQ

NYSDEC extensively analyzed the CMAQ model performance to evaluate model predictions against observations of ozone, $PM_{2.5}$, and other chemical species. To do this, model predictions for the base year simulation are compared to the actual ambient data observed in the historical episode. This verification is a combination of statistical and graphical evaluations. If the model appears to be predicting fine particles and other airborne pollutants in the right locations for the right reasons, then the model can be used as a predictive tool to evaluate various control strategies and their effects on regional haze. CMAQ modeling was conducted for the year 2002 (completed by cooperative modeling efforts from NYDEC, UMD, NJDEP, Rutgers, VADEP, and NESCAUM) under the Base B4 emission scenario (See Attachment P). CMAQ performance for $PM_{2.5}$ species and visibility is examined based on this CMAQ run on a 12 km resolution domain. Measurements from IMPROVE and STN networks are paired with model predictions by location and time for evaluation. Figure 9-3 presents the domain-wide paired comparison for sulfate and other PM2.5 species including nitrate, OC, EC, fine soil, and $PM_{2.5}$ daily average concentration from the CMAQ simulation and two sets of observations (STN and IMPROVE). It shows that predicted $PM_{2.5}$ sulfate and measured sulfate are in a good 1:1 linear relationship with varying from 0.6 to 0.7. $PM_{2.5}$ nitrate (top row right panel) also has close to a 1:1 linear relationship between the model and observations, although the values are much lower (from ~0.2 to ~0.5) than for sulfate. Paired OC (middle row left panel) concentrations have a scattered distribution with over- and under-estimation and a very weak linear relationship (r^2 of ~0.1). CMAQ tends to overestimate EC (middle row right panel) and fine soil (bottom row left panel) concentrations.[31]

[31] EC and soil are inert species not involved in chemical transformation. Poor emission inventory data may be the main cause for the weak linear relationships between prediction and measurement. In addition, there are no fire emissions considered in CMAQ modeling. The wild fire in Quebec, Canada in early July of 2002 led to high concentrations of observed OC, EC, and fine soil that are not predicted by CMAQ.

Figure 9-3
Domain-Wide Paired Comparison For Sulfate And Other $PM_{2.5}$ Species
CMAQ vs IMPROVE/STN



Because sulfate is the dominant $PM_{2.5}$ species, modeled $PM_{2.5}$ (bottom row right panel) shows a relatively strong near 1:1 linear relationship.

Additional model performance evaluations include assessing the ability of the CMAQ model to correctly model PM2.5 species across the modeling domain (spatial distribution of the correlation coefficient between CMAQ predictions and Improve observations), mean fractional error of CMAQ predictions, mean fraction bias of CMAQ predictions, and paired comparisons of the haze index between CMAQ predictions and Improve measurements at selected Class I sites were undertaken. In summary, the CMAQ model was demonstrated to perform best for daily average SO_4 mass and $PM_{2.5}$. Many other species vary significantly over the course of a day, or from day to day, and small model over- or under-prediction at low concentrations can lead to large biases on a composite basis. These model performance evaluations are described in detail in NYSDEC's technical support document TSD-1e, "CMAQ Model Performance and Assessment, 8-Hr OTC Ozone Modeling," February 23, 2006 (Attachment K) and in NESCAUM's report , "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment P).

9.4.2 REMSAD

The Regional Modeling System for Aerosols and Deposition (REMSAD) model was utilized by MANE-VU for its contribution assessment. REMSAD model performance has been evaluated as part of several previous national and regional modeling exercises. EPA evaluated REMSAD performance as for their Clear Skies Act base case study using 1996 meteorology and 1996 NET inventory.[32] Modeling results were compared with IMPROVE measurement, with REMSAD found to perform better in the Eastern US than in the Western US on PM sulfate and $PM_{2.5}$, although it underestimates ambient levels countrywide and performs relatively poorly on soil, carbonaceous aerosols and PM nitrate.[33]

A spatial performance evaluation of REMASAD simulations for sulfate on the 12km northeast US domain for the year 2002 was conducted through comparison with IMPROVE/STN measurements, as illustrated in Figure 9-4. These comparisons are inexact, because the discrete measurements represent a uniform gridded concentration field. This approach, however, does provide a first order examination of measurement and modeling results, which is appropriate for an annual averaged analysis.

In general, the REMSAD simulation field is well-matched with measurement data. Figure 9-5 shows the comparison of paired 24-hour surface sulfate concentrations between five different air quality model results (including REMSAD) and IMPROVE measurements during the year 2002 for Lye Brook Wilderness Area (Vermont) and

[32] See Clear Skies Act Air Quality Modeling Technical Support Document at http://www.epa.gov/air/clearskies/aq_modeling_tsd_csa2003.pdf

[33] NESCAUM also performed REMSAD modeling using the 1996 meteorology, but with the 2001 Proxy emission inventory, therefore a direct comparison to the EPA CSA modeling results could not be completed. To evaluate REMSAD for this exercise, NESCAUM first compared its own modeling results with EPA's CSA 2001 case modeling results, which also used the 1996 meteorology. NESCAUM's results were an exact match with EPA's REMSAD modeling on $PM_{2.5}$ and PM sulfate distributions. In addition, NESCAUM also compared the long term modeling average (annual mean) of PM species to IMPROVE annual means for three sites. These comparisons show good agreement for REMSAD modeling of PM sulfate, NH4, OC and EC.

Shenandoah National Park (Virginia). The comparison illustrates that the two CMAQ model runs show the best performance in terms of slope, intercept and coefficient of correlation (r2), with the REMSAD results showing the 2nd best performance. Along with EPA's previous evaluation (Timin B. et al., 2002) the NESCAUM performance evaluation confirms that REMSAD performs reasonably well for longer-term (annual averaged) sulfate simulation.

Figure 9-4
Sulfate Concentrations From the IMPROVE/STN Measurements and the REMSAD Model

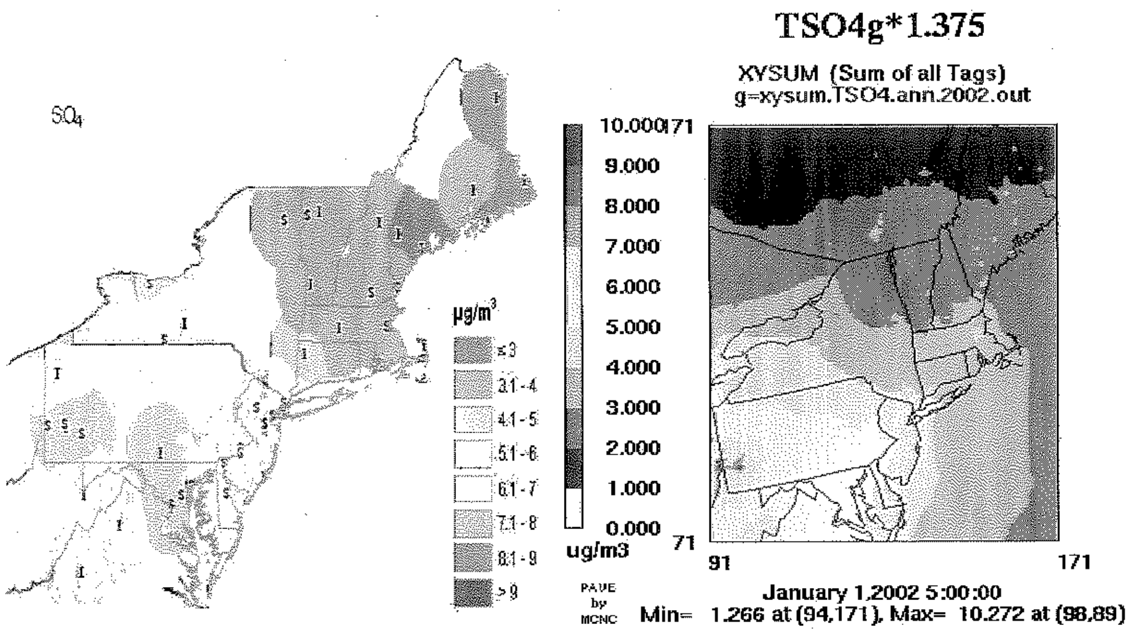
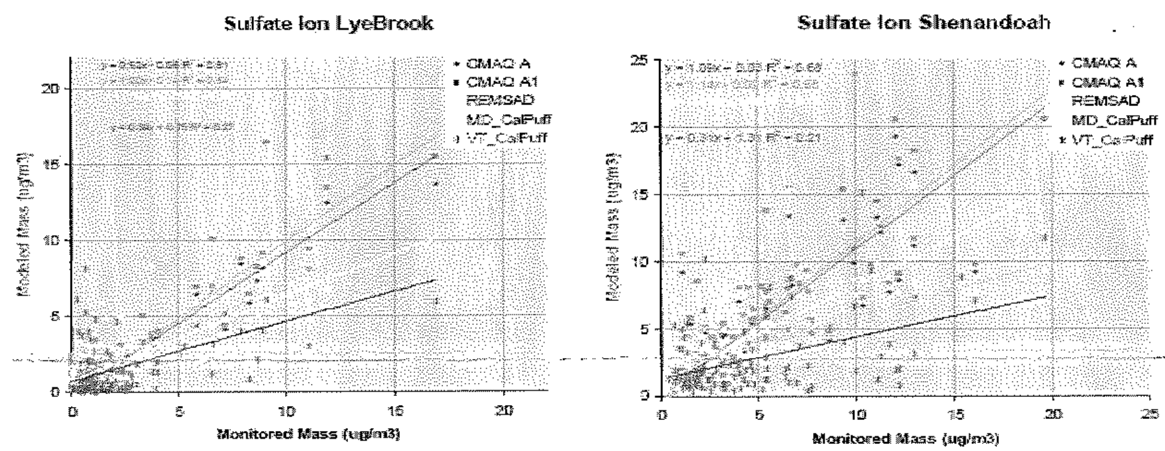


Figure 9-5
Comparison of Measurement and Modeled Data for Alternative Annual Model Simulations



9.5 Additional Modeling Platforms

9.5.1 CALGRID

In addition to the SIP-quality modeling platforms that were described above, an additional modeling platform was developed for use as a screening tool to evaluate additional control strategies or to perform sensitivity analyses. The CALGRID model was selected as the basis for this platform. CALGRID is a grid-based photochemical air quality model that is designed to be run in a Windows environment. In order to make the CALGRID model the best possible tool to supplement the SIP-quality CMAQ and REMSAD modeling, the current version of the CALGRID platform was set up to be run with the same set of inputs as the SIP-quality models. The CALGRID air quality simulations were run on the same 12-km eastern modeling domain that was used for CMAQ and REMSAD. This model's performance was relative to the performance of the already evaluated CMAQ and REMSAD models and was thus determined to perform adequately.

Conversion utilities were developed to re-format the meteorological inputs, the boundary conditions, and the emissions for use with the CALGRID modeling platform. Pre-merged SMOKE emissions files were obtained from the modeling centers and re-formatted for input into EMSPROC6, the emissions pre-processor for the CALGRID modeling system. EMSPROC6 allows the CALGRID user to adjust emissions temporally, geographically, and by emissions category for control strategy analysis. 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 emissions categories. These files by component were then converted for use with EMSPROC6, thus giving CALGRID users the flexibility to analyze a wide variety of emissions control strategies. The MANE-VU CALGRID modeling is described in greater detail in Attachment P.

9.5.2 CALPUFF

CALPUFF is a non-steady-state Lagrangian puff model that simulates the dispersion, transport, and chemical transformation of atmospheric pollutants. Two parallel CALPUFF modeling platforms were developed by the Vermont Department of Environmental Conservation (VTDEC) and the Maryland Department of the Environment (MDE). The VTDEC CALPUFF modeling platform utilized meteorological observation data from the National Weather Service (NWS) to drive the CALMET meteorological model. The MDE platform utilized the same MM5 meteorological inputs that were used in the modeling done in support of the ozone and regional haze SIPs. These two platforms were run in parallel to evaluate individual states' contributions to sulfate levels at Northeast and Mid-Atlantic Class I areas. The CALPUFF modeling effort is described in detail in NESCAUM's report, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006 (Attachment A).

10. Best Available Retrofit Technology

The Best Available Retrofit Technology (BART) requirement of Section 169A of the Clean Air Act (42 U.S.C.§7491(b)(2)(A)) and implementing rules (40 C.F.R. Part 51, Attachment Y) are intended to reduce visibility impairing pollutants[34] emitted from existing stationary sources which were grandfathered from the New Source Review (NSR) requirements of the Clean Air Act. The federal definition of BART in 40 CFR Part 51.301 is as follows:

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

The BART requirements apply to certain older industrial sources that began operating before the federal Prevention of Significant Deterioration (PSD) rules were adopted in 1977 to protect visibility in Class I areas. PSD and BART represent the two primary regulatory tools for protecting visibility and addressing regional haze from industrial sources. The PSD rules apply to new sources and major modifications of existing sources[35], while BART applies to 26 types of stationary sources which began operation between August 7, 1962 and August 7, 1977 with the potential to emit more than 250 tons per year of a visibility impairing pollutant. Once the Regional Haze SIP is approved by the EPA, the BART facility has up to five years to install the appropriate controls and comply with the established emission standards. Maine is requiring sources subject to BART to install, operate and maintain BART rather than implement an emissions trading program or other alternative measure.

10.1 The Federal BART Rule

In June 2005, EPA adopted the final BART rule. The BART rule requires states/tribes to develop an inventory of sources within each state or tribal jurisdiction that would be eligible for controls. The rule contains the following elements that:

---

[34] The visibility impairing pollutants are defined by the EPA as sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and particles with an aerodynamic diameter less than or equal to 10 and 2.5 μm (i.e., PM_{10} and $PM_{2.5}$, respectively).

[35] The PSD rules are part of the New Source Review rules, which apply to major new sources and major modifications of existing sources, to protect both visibility and air quality in general. See further description in Section 12. Since BART addresses existing sources, the evaluation of controls considers the effectiveness and the remaining life of the existing controls, and the cost of replacing them. While PSD and BART may end up evaluating similar types of controls, the criteria and selection of controls for BART is different due to the retrofit factors and visibility improvement that would result.

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

Beyond the specific elements listed above, EPA provided the states with a great deal of flexibility in implementing the BART program.

10.1.1 Federal BART Requirements for Electric Generating Units (EGUs)

According to 40 CFR Section 51.308(e)(4) of the Regional Haze Rule, a State that opts to participate in the Clean Air Interstate Rule (CAIR) Cap and Trade program under 40 CFR Part 96AAA-EEE need not require affected BART eligible EGUs to install, operate, and maintain BART. Since Maine and Maine sources were not included in the CAIR Cap and Trade Program, EGUs in Maine that are subject to BART must install, operate and maintain emission controls.

Section V of the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations Preamble sets forth presumptive requirements for States to require EGUs to reduce SO_2 and NO_x emissions for units greater than 200 MW in capacity at plants greater than 750 MW in capacity that significantly contribute to visibility impairment in Federal Class I areas. The analysis conducted presents alternative control scenarios of possible additional controls for EGUs located at plants less than 750 MW in capacity.

Under 40 CFR Section 51.308(e)(1)(i)(B) of the Regional Haze Rule, the determination of BART for fossil fuel fired power plants having a total generating capacity of greater than 750 megawatts must be made pursuant to the guidelines of Attachment Y of this part of the CFR (Guidelines for BART Determinations under the Regional Haze Rule). EPA adopted those guidelines on July 6, 2005. The guidelines provide a process for making BART determinations that States can use in implementing the regional haze BART requirements on a source-by-source basis, as provided in 40 CFR 51.308(e)(1). States must follow the guidelines in making BART determinations on a source-by-source basis for power plants of greater than 750 megawatts (MW), but are not required to use the process in the guidelines when making BART determinations for other types of sources. For oil-fired EGUs, the presumptive level of BART control for SO_2 is the use of oil containing 1 percent or less sulfur by weight. Combustion controls constitute the presumptive BART control for NO_x at these units.

10.2 Maine State BART Requirements

In 2007, the Maine Legislature enacted enabling legislation establishing deadlines and control requirements/limitations for BART eligible units in Maine[36]. 38 MRSA §603-A, sub-§8 states:

> "8. Best available retrofit technology or BART requirements. For those BART eligible units determined by the department to need additional sulfur air pollution controls to improve visibility, the controls must:
>
> A. Be installed and operational no later than January 1, 2013; and
>
> B. Either:
>
> (1) Require the use of sulfur oil having 1% or less of sulfur by weight; or
>
> (2) Be equivalent to a 50% reduction in sulfur emissions from a BART eligible unit based on a BART eligible unit source emission baseline determined by the department under 40 Code of Federal Regulations, Section 51.308 (d)(3)(iii)(2006) and 40 Code of Federal Regulations, Section 51 Attachment Y (2006)."

10.3 BART-Eligible Sources in Maine

Determining BART-eligible sources is the first step in the BART process. The Maine BART-eligible sources were identified in accordance with the methodology in Appendix Y of the Regional Haze Rule, Guidelines for BART Determinations Under the Regional Haze Rule, Part II, How to Identify BART-Eligible Sources (70 FR 39158). This guidance consists of the following criteria:

1. The facility contains emission units[37] which fall into one or more of 26 source categories:

   - Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input
   - Coal cleaning plants (thermal dryers)
   - Kraft pulp mills
   - Portland cement plants
   - Primary zinc smelters
   - Iron and steel mill plants
   - Primary copper smelters
   - Municipal incinerators capable of charging more than 250 tons of refuse per day
   - Hydrofluoric, sulfuric, and nitric acid plants

[36] Sources may also cap their emissions below the 250 ton BART eligibility threshold.

[37] EPA rules (40 CFR Part 51.166) define *emission unit* as "any part of a stationary source that emits or has the potential to emit any pollutant".

- Petroleum refineries
- Lime plants
- Phosphate rock processing plants
- Coke oven batteries
- Sulfur recovery plants
- Carbon black plants (furnace process)
- Primary lead smelters
- Fuel conversion plants
- Sintering plants
- Secondary metal production facilities
- Chemical process plants
- Fossil-fuel boilers of more than 250 million BTUs per hour heat input
- Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels
- Taconite ore processing facilities
- Glass fiber processing plants
- Charcoal production facilities

2. The units "began operation" after August 7, 1962 (defined as "engaged in activity related to the primary design function of the facility"), and were the units "in existence on August 7, 1977 (defined as "the owner or operator has obtained all the necessary pre-construction approvals or permits required by Federal, State or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into a binding agreements or contractual obligation, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time").

   [Note: Sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period are also subject to BART if "the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source"]

3. The potential emissions from these units 250 tons per year or more for sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOC), or ammonia (NH4). The BART Guidelines recommend addressing SO_2, NO_x, and particulate matter. The State of Maine addressed these three pollutants, and used particulate matter less than 10 microns in diameter (PM_{10}) as an indicator for particulate matter to identify BART eligible units, as the Guidelines suggest. Consistent with the Guidelines, the State of Maine did not evaluate emissions of VOCs and ammonia in BART determinations for these reasons:

   - The majority of VOC emissions in Maine are biogenic in nature, with the areas near Maine Class I areas especially so (the ability to further reduce total ambient VOC concentrations at Class I areas is limited);
   - Point, area and mobile sources of VOCs in Maine are already comprehensively controlled as part of our ozone attainment and maintenance strategy;

- The overall ammonia inventory is very uncertain, and the amount of anthropogenic emissions at sources that were BART-eligible was relatively small, and
- No additional sources were identified that had greater than 250 tons per year ammonia and required a BART analysis.

The identification of BART sources in Maine was undertaken as part of a multi-state analysis conducted by the Northeast States for Coordinated Air Use Management (NESCAUM). NESCAUM worked with Maine DEP licensing engineers to review all sources and determine their BART eligibility. Maine DEP identified 10 sources as BART-eligible. These sources are listed below in Table 10-1.

10.4 Sources Subject to BART

Maine, working with MANE-VU, found that every MANE-VU state with BART-eligible sources contributes to visibility impairment at one or more Class I areas to a significant degree (See the MANE-VU Contribution Assessment in Attachment A). As a result, Maine has found that all eligible sources within Maine are subject to BART. The State of Maine is utilizing this option for demonstrating its sources are reasonably anticipated to cause or contribute to visibility impairment at Class I areas for three reasons: (1) the BART sources represent an opportunity to achieve greater reasonable progress; (2) additional public health and welfare benefits will accrue for the resulting decreases in fine particulate matter; and (3) to demonstrate its commitment to federal land managers (FLMs) and other RPOs as it seeks the implementation of reasonable measures in other states.[38]

According to Section III of the 2005 Regional Haze Rule, once the state has compiled its list of BART-eligible sources, it needs to determine whether to make BART determinations for all of the sources or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area.

Based on the collective importance of BART sources, Maine has decided that no exemptions would be given for sources; a BART determination will be made for each BART-eligible source.

10.5 MANE-VU BART Modeling

MANE-VU conducted modeling analyses of BART-eligible sources using CALPUFF in order to provide a regionally-consistent foundation for assessing the degree of visibility improvement which could result from installation of BART controls (See Attachment L).

[38] Maine's decision that all BART eligible sources are subject to BART should not be misconstrued to mean that all BART-eligible sources must install BART. Maine's approach simply requires the consideration of each of the five statutory factors before determining whether or not controls are warranted.

Table 10-1
BART-Eligible Sources in Maine

Source and Unit	Location	I.D	BART Source Category
FPLE Wyman Station Boiler #3 Boiler #4	Yarmouth, ME	2300500135 -004 -005	SC 1- Fossil fuel fired electric plants
Domtar Power Boiler #9 Lime Kiln	Woodland, ME	2302900020 -001 -002	SC 3 - Kraft pulp mills
Dragon Products Kiln	Thomaston, ME	2301300028 -005	SC 4 – Portland cement plants
Red Shield Acquisition, LLC #4 Recovery Boiler Lime Kiln	Old Town, ME	2301900034 -002 -004	SC 3 - Kraft pulp mills
Verso Bucksport #5 Boiler	Bucksport, ME	2300900004 -001	SC 22 – Fossil fuel fired boilers
SAPPI Somerset Recovery Boiler Smelt Tanks #1, #2 Lime Kiln	Hinckley, ME	2302500027 -003 -007 -004	SC 3 - Kraft pulp mills
Verso Androscoggin Power Boiler #1 Power Boiler #2 Waste Fuel Incinerator Recovery Boilers #1 and #2 Smelt Tank #1 Smelt Tank #2 Lime Kiln A Lime Kiln B Flash Dryer	Jay, ME	2300700021 -001 -002 -003 -004/005 -009 -010 -007 -008 -018	SC 3 - Kraft pulp mills
Katahdin Paper Power Boiler #4	Millinocket, ME	2301900056 -004	SC 22 – Fossil fuel fired boilers
Lincoln Paper and Tissue Recovery Boiler #2	Lincoln, ME	2301900023 -002	SC 3 - Kraft pulp mills
Rumford Paper Power Boiler #5	Rumford, ME	2301700045 -003	SC 3 – Kraft pulp mills

While this modeling analysis differed slightly from the statutory language, it was intended to provide a first-order estimate of the maximum visibility benefit that could be achieved by eliminating all emissions from a BART source, and provides a useful metric for determining which sources are unlikely to warrant (additional) controls to satisfy BART.

The MANE-VU modeling effort analyzed 136 BART-eligible sources in the MANE-VU region using the CALPUFF modeling platform and two meteorological data sets: 1) a wind field based on National Weather Service (NWS) observations; and 2) a wind field based on the MM5 meteorological model (MM5 2006). Modeling results from both the NWS and MM5 platforms include each BART eligible unit's maximum 24-hr, 8th highest 24-hr, and annual average impact at the Class I area. These visibility impacts were modeled relative to the 20 percent best, 20 percent worst, and average annual natural background conditions. In accordance with EPA guidance, which allows the use of either estimates of the 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 modeling purposes, MANE-VU opted to utilize the more conservative best conditions estimates approach because it is more protective of the region.

The 2002 baseline modeling provides an estimate of the maximum improvement in visibility at Class I Areas in the region that could result from the installation of BART controls (the maximum improvement is equivalent to a "zero-out" of emissions). In virtually all cases, the installation of BART controls would result in less visibility improvement than what is represented by a source's 2002 impact, but this approach does provide a consistent means of identifying those sources with the greatest contribution to visibility impairment.

In addition to modeling the maximum potential improvement from BART, MANE-VU also determined that 98 percent of the cumulative visibility impact from all MANE-VU BART eligible sources corresponds to a maximum 24-hr impact of .22 dv from the NWS-driven data and 0.29 dv from the MM5 data. As a result, MANE-VU concluded that, on the average, a range of 0.2 to 0.3 dv would represent a significant impact at MANE-VU Class I areas, and sources having less than 0.1 dv impact are unlikely to warrant additional controls under BART.[39]

Table 10-2 illustrates the modeled impacts (maximum) of Maine BART-Eligible sources on selected Class I areas in Maine and New Hampshire. For this table, SO_4, NO_3 and PM_{10} modeled impacts at these Class I areas were totaled to provide an estimate of the maximum 24-hr impact at these nearby Class I areas. It should be noted that a number of BART-eligible sources (highlighted) have less than a 0.1 deciview impact on Class I areas.

[39] As an additional demonstration that sources whose impacts 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 at each Class I suite. The results of this modeling demonstrated that the maximum 24-hour 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 well below the 0.5 dv impact recommended by EPA for exemption modeling and used by most other RPOs.

10.6 The Maine BART Analysis Protocol

40 CFR 51.308(e)(1)(ii)(A) requires that, for each BART-eligible source within the state, any BART determination must be based on an analysis of the best system of continuous emission control technology available and the associated emission reductions achievable. In addition to considering available technologies, this analysis must evaluate five specific factors for each source:

1. The costs of compliance,
2. The energy and non-air quality environmental impacts of compliance,
3. Any existing pollution control technology in use at the source,
4. The remaining useful life of the source, and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

Although Maine did not exempt any BART-eligible sources from a BART determination, it did utilize the MANE-VU zero-out modeling (described in the previous section) as a surrogate for estimating the visibility improvement reasonably expected from the application of controls. As previously highlighted in Table 10-2, there are ten BART-eligible sources with less than 0.1 deciview impact at any Class I area, with these impacts ranging from a low of 0.0018 deciviews to a higher (but still insignificant) 0.0822 deciviews. Since zero-out modeling shows that the elimination of all emissions from these sources would provide only insignificant visibility benefits at nearby Class I areas, and recognizing that the majority of these units already have controls fully satisfying BART requirements, the Department used the "anticipated visibility improvement from BART" factor to determine the scope of the BART analysis and whether visibility impact modeling need be performed by specific sources. The Maine approach is consistent with that used by other MANE-VU states that are <u>not</u> allowing sources to utilize exemption modeling. With the Maine approach, all BART-eligible sources were required to undertake an engineering analysis of their existing and possible future controls. If an emissions unit was found to be well-controlled (in comparison with possible future controls), and the visibility impacts of the unit relatively small[40] as determined by the MANE-VU zero-out modeling, BART was determined by existing controls, and additional visibility impact modeling was not necessary (for a more detailed look at Maine's BART process, see Attachment M-1).

10.7 Summary of Maine BART Determinations

The following section details the BART determinations for all BART-eligible sources in Maine. All BART requirements are incorporated in a Title V air emissions license (operating permit) for each source; draft Title V licensee are included in Attachment M.

[40] Sources with less than 0.1 deciview impact on Class I areas are presumed to have a small impact.

Table 10-2
Modeled Impacts (Deciviews) of Maine BART-Eligible Sources at Selected MANE-VU Class I Areas

(Sources with < 0.1 deciview total impact highlighted)

Facility Name	Stack Name	NWS CALPUFF				MM5 CALPUFF			
		Total	SO4	NO3	PM10	Total	SO4	NO3	PM10
		24-hr dv impact				24-hr dv impact			
FPLE Wyman Station	Boiler_4	0.1423	0.1276	0.0334	0.0010	0.4749	0.3846	0.1072	0.0005
FPLE Wyman Station	Boiler_3	0.2212	0.1715	0.0704	0.0004	0.3049	0.2545	0.0508	0.0014
Domtar Ind.	#9_Power_Boiler	1.3630	0.2828	0.7988	1.3134	1.6506	0.1815	0.7279	1.3717
Domtar Ind.	Lime_Kiln	0.5296	0.0559	0.4309	0.1207	0.4589	0.0427	0.3820	0.1048
Dragon Products	Kiln	2.0155	0.2434	1.7614	0.0604	1.8626	0.3208	1.7234	0.0413
Red Shield Acquisition, Old Town	#4_Recovery_Boiler	0.2425	0.0634	0.1633	0.0173	0.2631	0.0424	0.2070	0.0391
Red Shield Acquisition, Old Town	Lime_Kiln	0.0851	0.0171	0.0433	0.0278	0.1338	0.0138	0.0855	0.0463
Verso, Bucksport	Boiler_#5	0.0543	0.0260	0.0267	0.0021	0.1591	0.0817	0.0721	0.0098
SAPPI Somerset	Recovery_Boiler	0.2159	0.0151	0.1971	0.0087	0.4421	0.0179	0.4168	0.0158
SAPPI Somerset	Smelt_Tanks_#1_and_#2	0.0108	0.0034	0.0000	0.0095	0.0000	0.0000	0.0000	0.0000
SAPPI Somerset	Lime_Kiln	0.0380	0.0270	0.0105	0.0012	0.0651	0.0455	0.0187	0.0010
Verso, Androscoggin	Power_Boiler_#1	0.6948	0.5720	0.1235	0.0094	1.7631	1.2176	0.5867	0.0290
Verso, Androscoggin	Power_Boiler_#2	0.7223	0.5948	0.1287	0.0095	1.8289	1.2646	0.6105	0.0293
Verso, Androscoggin	Waste_Fuel_Incinerator Boiler_	0.4256	0.0036	0.3651	0.0591	0.4956	0.0064	0.4544	0.0367
Verso, Androscoggin	Recovery_Boiler_#1_and_#2	0.1101	0.0454	0.0598	0.0078	0.3856	0.0952	0.2723	0.0215
Verso, Androscoggin	Smelt_Tank_#1	0.0139	0.0002	0.0000	0.0137	0.0122	0.0002	0.0000	0.0120
Verso, Androscoggin	Smelt_Tank_#2	0.0129	0.0004	0.0000	0.0125	0.0135	0.0006	0.0000	0.0129
Verso, Androscoggin	Lime_Kiln_A	0.0441	0.0001	0.0273	0.0167	0.0457	0.0004	0.0337	0.0123
Verso, Androscoggin	Lime_Kiln_B	0.0296	0.0001	0.0197	0.0098	0.0293	0.0004	0.0228	0.0062
Verso, Androscoggin	Flash_Dryer	0.0222	0.0044	0.0173	0.0005	0.0252	0.0097	0.0175	0.0003
Katahdin Paper Millinocket	PB_#4	0.8293	0.6630	0.1569	0.0210	0.4458	0.3832	0.1164	0.0216
Lincoln Paper and Tissue	Recovery_Boiler_#2	0.1151	0.0141	0.0806	0.0224	0.1200	0.0073	0.0882	0.0322
Rumford Paper	PB_#5	0.0369	0.0039	0.0327	0.0026	0.1025	0.0108	0.0897	0.0020

> 0.1 dv TOTAL and a pollutant | > 0.1 dv TOTAL only

10.7.1 Cap-Outs and Shutdowns

EPA guidance allows BART-eligible sources to adopt a federally enforceable permit limit to permanently limit emissions of visibility impairing pollutants to less than 250 tons per year, thereby "capping-out" of BART. Four Maine sources capped out of BART:

1. Katahdin Paper Company, LLC
2. Red Shield Acquisition, LLC
3. Rumford Paper Company
4. Verso Bucksport, LLC

These sources have actual emissions of visibility impairing pollutants of fewer than 250 tons per year, and are BART-eligible only because their potential emissions (PTE) exceed the statutory threshold of 250 tons per year. Pursuant to their requests, the Maine DEP has established federally enforceable permit conditions that limit the PTE of these units to less than the statutory threshold of 250 tons per year for all visibility impairing pollutants, which makes these units not subject to BART requirements.

Federally enforceable terms and conditions were established for each source that limit the PTE for SO_2, PM_{10} and NO_x to less than 250 TPY. Note that if, in the future, the source requests an increase in PTE greater than 250 tons per year per visibility impairing pollutant, then they shall be subject to the Best Available Retrofit Technology (BART) provisions of the Environmental Protection Agency's (EPA) Regional Haze Program Requirements (40 Code of Federal Regulations, Part 51, Section 308).

10.7.2 Maine BART Determinations

In general, the following determinations summarize the controls and limits that are currently required under existing air emission licenses (as noted), or will be required specifically due to BART.

1. Domtar Maine, LLC

The Domtar Woodland Pulp facility is a pulp mill, which utilizes the Kraft Pulping process and produces market pulp. The Mill also operates support facilities including woodyards, wastewater treatment plant, sludge press, pulp production labs, environmental labs, finishing, shipping, and receiving operations, storage areas, a landfill, and a power boiler. There are two BART eligible units at the facility; the #9 Power Boiler, and the Lime Kiln.

#9 Power Boiler is rated at 625 MMBtu/hr and was placed into operation in 1971. #9 Power Boiler is fueled primarily by biomass but is also licensed to burn #6 fuel oil, sludge, TDF, specification waste oil, HVLC, LVHC, mill yard waste, oily rags, stripper off-gas, and propane. Emissions are controlled using a variable-throat wet venturi scrubber and low-NO_x burners. The Lime Kiln is rated at 75 MMBtu/hr and was placed into operation in 1966. Emissions are controlled using a variable-throat wet venturi scrubber and a Ceilcote cross-flow scrubber. The Lime Kiln is fueled by #6 fuel oil.

BART Analysis Summary

#9 Power Boiler

PM: Domtar evaluated the use of Fabric Filters, Wet Electrostatic Precipitator (WESP), Dry Electrostatic Precipitator (DESP), and Wet Scrubbers to control PM at the #9 Power Boiler. Fabric filters were found not technically feasible due to fire risk from combustible fly-ash, while WESP is not technically feasible due to operational difficulties with multi-fuel boilers. A DESP could not be installed post-scrubber due to excess moisture levels, but could be installed upstream. A DESP was evaluated and found to provide a 98-99% control efficiency for biomass a 90% efficiency for oil (for comparison, a wet scrubber provides an 85-98% control efficiency) . Domtar estimated the cost for DESP installation at $4,640 per ton of PM removed, and found that DESP is not a cost-effective option.

SO_2: Power Boiler #9 is currently controlled through the use of a wet scrubber and low sulfur fuel (biomass). Domtar did not investigate other control technologies because the combination of low sulfur fuel and wet scrubber provides maximum emission reductions from this unit.

NO_x: Domtar identified a number of potential NO_x control strategies for use on Power Boiler #9, including: NO_x tempering, flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), low NO_x burners and good combustion practices. Several potential NO_x controls were found to be technically infeasible, and did not warrant further investigation. NO_x tempering is not technically feasible due to reduced thermal efficiency and increased fuel usage, SCR is not technically feasible due to the increased frequency of catalyst fouling from multi-fuel boilers, and FGR is not technically feasible based on previous failed FGR trials conducted on the #9 Power Boiler. SNCR, with a 30-40% control efficiency, and low NO_x Burners, with 10% control efficiency, were identified as technically feasible control strategies. Domtar's analysis estimated the cost-effectiveness of SNCR at $7,360 per ton, and noted that SNCR has a reduced effectiveness on boilers with significant load swings (such as Power Boiler #9). Given the low cost-effectiveness of SNCR, Domtar identified the continued use of low NO_x burners as BART.

Lime Kiln

PM: The Lime Kiln is subject to the MACT standard for PM found in 40 CFR, Part 63, Subpart MM. According to 40 CFR, Part 51, Appendix Y, According to 40 CFR Part 51, Appendix Y, Section IV (C), an exemption is made that states "We believe that, in many cases, it will be unlikely that States will identify emission control standards more stringent than the Maximum Achievable Control Technology (MACT) standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for the purposes of BART." Since this current MACT requirement satisfies the requirements of BART, no further analysis was undertaken.

SO_2: Domtar identified the use of a wet scrubber and in-process capture as feasible technologies for the control of SO_2 from the lime kiln. Since both technologies are currently employed by Domtar (including two wet scrubbers), no further analysis was necessary.

NO_x: A number of potential NO_x control strategies were identified for the lime kiln, including: SNCR, SCR, non-selective catalytic reduction (NSCR), FGR, low NO_x burners and good combustion practices. The impracticality of installing chemical injection nozzles inside a rotating Kiln drum makes SNCR technically infeasible. SCR and NSCR are not feasible due to the known presence of catalyst fouling substances in the Lime Kiln. FGR is not feasible as it reduces the temperature in the flame zone, thus hindering the chemical reaction taking place in the Lime Kiln. Low NO_x burners are a non-demonstrated technology and are not listed in the EPA BACT/RACT/LEAR Clearinghouse for Lime Kiln emissions control. Good combustion practices are the only feasible option, which is already employed at the Lime Kiln. No further analysis is necessary.

BART Determination for Domtar

Unit	PM		SO_2		NO_x	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
#9 Power Boiler	Wet scrubber	0.15 lb/MMBtu (Existing Title V license)	Wet scrubber	0.3 lbs/MMBtu on a 24-hour basis (BART order)	Low-NO_x burners	0.4 lb/MMBtu on a 24-hour basis (Existing Title V license)
Lime Kiln	Wet scubber	Compliance with 40 CFR Part 63 Subpart MM	Wet scrubber/Process control	8.3 lbs/hr. (Existing Title V license)	Good combustion practices	120 ppmvd @10% O_2 (Existing Title V license)

2. Dragon Products Company

Dragon operates a cement manufacturing facility in Thomaston. The facility, built in 1971, was initially a wet process cement kiln that was converted to the more efficient dry cement manufacturing process beginning in 2003. The modernization project converted the existing wet process cement kiln to a dry process (preheater/precalciner type), converted the existing (wet) raw mill to a pregrinding finish cement mill, and improved other ancillary operations within the facility. The planned annual production rate of the new facility is approximately 766,500 tons of clinker.

The BART eligible kiln system is a single dry process rotary kiln and inline raw mill equipped with a preheater/precalciner. Various allowable fuels, including petcoke, #2 fuel oil, #4 fuel oil, specification waste oil, non-specification waste oil, whole tires, and tire chips provide thermal energy necessary to convert raw materials (limestone, silica, iron ore, fly ash, and/or other raw material additives) into calcium silicates or 'clinker'. Hot flue gases from the kiln flow counter-current to the feed material up the length of the kiln. Heat is transferred to the fed material from the direct contact of the flue gases in the kiln and preheater/precaliner tower.

BART Analysis Summary

Dragon submitted a 5-step BART analysis of the technical feasibility and cost of compliance, the energy and non-air quality impacts of compliance, any existing air pollution control technology in use at the source, the remaining useful life of the source, and the degree of visibility improvement anticipated from the use of BART (a CALPUFF version 5.8 analysis was performed by Dragon).

PM: Emissions of PM from the kiln system are generated as a function of the clinker production process. The kiln system is subject to 40 CFR Part 63, Subpart LLL, *National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry*. Since the MACT is current and Dragon complies with the particulate matter limits in §63.1343 and uses a fabric filter dust collector for PM_{10} control, no further BART analysis was performed.

SO_2: Emissions of SO_2 from cement kilns are generally related to the inherent SO_2 removal efficiency present in the kiln system operation itself, the pyritic sulfur concentration of the raw feed materials, the sulfur to alkali ratio of the raw feed materials, and whether the prevailing condition of the system is oxidizing or reducing. Dragon identified wet scrubbing, semi-dry scrubbing, dry scrubbing, fuel switching, and process alterations as possible retrofit control technologies for reducing SO_2 emissions.

Wet caustic scrubbing, where one or more soluble components of an acid gas are dissolved in a liquid with a low volatility, semi-dry scrubbing, based on atomizing a reagent slurry stream containing lime and contacting the flue gases in a spray dryer type vessel, and dry scrubbing, consisting of injecting a dry reagent into the gas stream prior to the particulate matter control device, were considered technically feasible for the kiln system and were further evaluated[41]. The three scrubbing options were reviewed further, and the results are in the following table:

[41] A dry scrubbing system is currently installed on the kiln system but is not operated.

Control Technology	Expected SO_2 Emission Rate (tons/yr)	Emissions Performance Level	Expected SO_2 Emissions Reductions (tons/yr)	Cost of Compliance
Wet Scrubbing	49.0	95%	46.6	Total Cap. Investment: \$9,419,115 Total Annualized Cost:\$2,238,950 Ave Cost Effectiveness:\$48,098/ton Ave Cost Effectiveness per deciview: \$12,508,101/dv
Semi-Dry Scrubbing	49.0	90%	44.1	Total Cap. Investment: \$2,359,464 Total Annualized Cost:\$675,978 Ave Cost Effectiveness:\$15,328/ton Ave Cost Effectiveness per deciview: \$3,907,387/dv
Dry Scrubbing	49.0	50%	24.5	Total Cap. Investment: \$0 Total Annualized Cost:\$245,737 Ave Cost Effectiveness:\$10,030/ton Ave Cost Effectiveness per deciview: \$2,254,468/dv

Based on capital costs associated with the additional retrofit controls, the resultant SO_2 control cost effectiveness values, and the predicted visibility at the nearest Class I area, it was determined that these are not viable BART options.

Fuel switching and process alterations were also evaluated, but were not found to be viable control options.

<u>NO_X</u>: Emissions of NO_X from cement kilns are generally related to thermal NO_X, fuel NO_X, and raw feed material NO_X. Dragon identified fuel switching, process optimization, flue gas recirculation (FGR), indirect fuel firing, staged air combustion/mid-kiln firing, low NO_X burners, selective Non-Catalytic Reduction (SNCR), and Selective Catalytic Reduction (SCR) as available NO_x control retrofit technologies.

Fuel switching was not considered technically feasible since the nitrogen content of the fuel used in the kiln burning zone has little or no effect on NO_X generation in a portland cement kiln. Flue gas recirculation was not considered technically feasible since the effectiveness of FGR relies on cooling the flame and generating a reducing combustion atmosphere to reduce thermal NO_X emissions, which is not compatible with the high flame temperature and an oxidizing combustion zone atmosphere in the kiln system required to produce quality clinker. SCR was not considered technically feasible since there are no full scale SCR systems (ammonia injection upstream of a catalyst bed) in operation at cement kilns in the United States due to various concerns including exhaust temperature and plugging.

Process optimization is currently being used on the kiln system, with advanced computer controls and instrumentation to improve overall facility operation and fuel efficiency.

Indirect fuel firing is currently the kiln system's method of operation, whereby pulverized solid fuel from a solid fuel mill is captured in a cyclone or fabric filter and is stored before being conveyed to the kiln. This separates the mill conveyance air from the fuel and the fuel is introduced in a controlled manner from storage, reducing primary kiln combustion air to less than 10% of the total combustion air (in a direct-fired cement kiln, the primary combustion air can make up to 20% of the total combustion air). Staged air combustion/mid-kiln firing is currently being used in the kiln system to reduce kiln stratification and improve combustion of the fuel, which aids in reducing emissions. Low NO_X burners are currently being used on the kiln system. SNCR is currently being used on the kiln system, with ammonia injection at a location in the correct temperature range for proper reaction to reduce NO_X emissions.

Dragon initially proposed the use of the existing NO_X controls as they are currently operated as BART. However, the Department requested additional information on the use of the SNCR technology at the facility relating to further NO_X control. Dragon supplied possible operational changes to the existing SNCR control unit including: increasing the operating time of the SNCR control unit, relocating the reagent injection nozzles, changing the reagent used in the SNCR control unit, and increasing the injection rate of the SNCR control unit reagent. The unit is already operated whenever the kiln is in operation so changing the operating time is not feasible. Relocating the injection nozzles or changing the reagent (19% aqueous ammonia) is not feasible, since the SNCR unit operates at the optimum injection point and reagent type based on the original trial test. Increasing the injection rate is a feasible option.

Records show that from April 2005 through December 2008, the SNCR operated at an average control efficiency of approximately 22%, and in 2008, the efficiency was slightly lower at 18%. Since the June 18, 2008 comments of the MACT standards for the Portland Cement amendments, EPA has stated that that 'for an SNCR (control unit) with optimal injection configuration and reagent injection rate, a 50% NO_X emission reduction represents a reasonable level of performance of SNCR over the long term,." The Department requested that Dragon assess the operation of the SNCR at 50% efficiency. Dragon performed an operational change impact analysis with the following results:

Control Technology	Expected NO_X Emission Rate (tons/yr)	Emissions Performance Level	Expected NO_X Emissions Reductions (tons/yr)	Cost of Compliance
SNCR operating at 50%	1130.6	927.1	565.3	Total Cap. Investment: $0 Total Annualized Cost:$1,483,877 Ave Cost Effectiveness:$4101/ton Ave Cost Effectiveness per deciview: $7,419,385/dv

Dragon proposed no increased reagent reaction rate due to additional cost, additional ammonia slip, and no perceptible change in visibility at the nearest class I area (Acadia

National Park). However, the Department is setting a 45% removal efficiency requirement to further reduce NO_X.

BART Determination

The Department determined BART for Dragon as follows:

BART Determination for Dragon Products Company

Unit	PM		SO_2		NO_x	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
Kiln	baghouse	9.3 lb/hr and 0.3 lb/ton dry kiln feed (Existing Title V license; 40 CFR Part 63)	N/A	70.00 lb/hr. on a 90-day rolling average (Existing Title V license) and 200 tons/year on a 12-month rolling average (BART order)	SNCR 45% control efficiency on a 24-hour basis (BART order)	350.0 lb/hr on a 90-day rolling average and 1533.0 tons per year on a 12-month rolling total basis (Existing Title V license)

3. FPL Energy Wyman, LLC.

FPLE Wyman is an 850-megawatt electric generating facility located on Cousins Island in Yarmouth, Maine. The plant consists of four generation units, all of which fire #6 residual fuel oil. A fifth unit is a smaller oil-fired auxiliary boiler which provides building heat and auxiliary steam and a sixth unit is an emergency backup diesel generator that provides electricity for use on-site. There are two BART eligible units at the facility- Unit 3 and Unit 4.

Boiler #3 is a Combustion Engineering boiler, installed in 1963, with a maximum design heat input capacity of 1190 MMBtu/hr firing #6 fuel oil (2% sulfur). The boiler is equipped with multiple centrifugal cyclones for control of particulate matter and optimization and combustion controls for NO_X. Boiler #4 is a Foster Wheeler boiler, installed in 1975, with a maximum design heat input capacity of 6290 MMBtu/hr firing #2 or #6 fuel oil (0.7 % sulfur). The boiler is equipped with an electrostatic precipitator for control of particulate matter and optimization and combustion controls for NO_X.

BART Analysis Summary

PM: Emissions of PM from oil fired boilers are a function of fuel firing.[42] Both boilers #3 and #4 have high efficiency combustion systems in conjunction with PM control devices; boiler #3 having multiclones and boiler #4 having an ESP. The cost analysis of installing an ESP on boiler #3 resulted in pollutant removal cost effectiveness of $19,000/ton of PM removed and visibility improvement cost effectiveness of $143 million per deciview of visibility improvement. This was determined to be excessive and not cost-effective.

SO_2: Emissions of SO_2 from oil fired boilers are related to the sulfur in the fuel. FPLE Wyman identified the following available retrofit control technologies for reducing SO_2 emissions from the oil fired boilers: low sulfur #2 fuel oil, reduced sulfur #6 fuel oil, and wet or dry scrubbers. Low sulfur #2 fuel oil (0.05% down to 0.0015%) and the use of reduced sulfur #6 fuel oil (1% or less) were considered technically feasible options. Post combustion controls of wet or dry scrubbers on large boilers were researched and generally only typically applied to coal fired boilers. The use of scrubbing systems on oil fired boilers is considered cost prohibitive and was not considered as a BART option.

FPLE Wyman performed a cost analysis on lowering the sulfur content in both boilers. Boiler #3 currently fires 2% sulfur oil and boiler #4 currently fires 0.7% sulfur oil. The annual costs were calculated to be the following (based on the differential fuel costs):

Boiler #3		Boiler #4	
% sulfur	Annual Costs	% sulfur	Annual Costs
1.0	$0.68 million	-	-
0.7	$0.80 million	-	-
0.5	$3.2 million	0.5	$9.2 million
0.3	$5.7 million	0.3	$18.3 million

The visibility cost effectiveness, incremental visibility improvement, and incremental visibility cost effectiveness from switching from 2% sulfur to reduced sulfur content fuel oil for boiler #3 was the following:

% Sulfur	Ranked Visibility Impact	Visibility Cost Effectiveness ($/deciview)	Incremental Visibility Improvement	Incremental Visibility Cost Effectiveness ($/deciview)
1.0	1st	$0.69 million	-	-
	8th	$1.95 million	-	-
0.7	1st	$0.56 million	0.44 dv	$0.27 million
	8th	$1.67 million	0.13 dv	$1.92 million

[42] It is estimated from the MANE-VU August 2006 document *Contributions to Regional Haze in the Northeast and Mid-Atlantic United States, Tools and Techniques for Apportioning Fine Particle/Visibility Impairment in MANE-VU* (pages 3-2, 4-7, 4-8) that course particulate matter has typically less than 4% of the contribution to visibility impairment at the MANE-VU Class I areas.

0.5	1st 8th	\$1.82 million \$5.41 million	0.35 dv 0.12 dv	\$6.97 million \$20.3 million
0.3	1st 8th	\$2.64 million \$8.12 million	0.37 dv 0.10 dv	\$6.59 million \$24.4 million

The visibility cost effectiveness, incremental visibility improvement, and incremental visibility cost effectiveness from switching from 0.7% sulfur to reduced sulfur content fuel oil for boiler #4 was the following:

% Sulfur	Ranked Visibility Impact	Visibility Cost Effectiveness (\$/deciview)	Incremental Visibility Improvement	Incremental Visibility Cost Effectiveness (\$/deciview)
0.5	1st 8th	\$22.3 million \$39.8 million	- -	- -
0.3	1st 8th	\$19.5 million \$35.2 million	0.53 dv 0.29 dv	\$17.3 million \$31.6 million

Based on the sulfur contributions in the Northeast and the information above, FPLE Wyman proposed 1% sulfur fuel oil for boiler #3 beginning in 2013, and the current sulfur limit of 0.7% for boiler #4 as BART.

NO_X: Emissions of NO_X from oil fired boilers are from thermal and fuel NO_X. In order to minimize NO_X emissions, FPLE Wyman installed combustion control technologies pursuant to 06-096 CMR 145, *NO_X Control Program Regulation.* FPLE Wyman installed combustion control technology upgrades including low NO_X fuel atomizers, improved swirler design, and overfire and interstage air ports. The burners were optimized and fuel/air flows were balanced to the burners on each unit. The combustion control technology upgrades were completed in April 2003 and reductions of 29-35% have been documented with boiler #3 and reductions of 24-47% have been documented with boiler #4 depending on each unit's load. These reductions are equivalent to the use of SNCR (Selective Non-Catalytic Reduction) technology on the boilers.

The cost analysis of installing additional NO_X controls of regenerative selective catalytic reduction (RSCR) on the boilers in addition to the current combustion controls resulted in a pollutant removal cost effectiveness of \$125,000/ton and \$83,000/ton of NO_X removed for boiler #3 and boiler #4, respectively. This was determined to be excessive and not cost effective.

BART Determination

The Department determined BART for FPLE Wyman as follows:

BART Determination for FPLE Wyman

Unit	PM		SO_2		NO_x	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
Boiler #3	multiclones	0.15lb/MMBtu (BART order)	Low-sulfur oil	1% sulfur by weight oil (BART order)	Combustion engineering	0.175 lb/MMBtu on a 90-day rolling average* (Existing Title V license; 06-096 CMR Chapter 145)
Boiler #4	ESP	0.1 lb/MMBtu (Existing Title V license; 40 CFR Part 60)	Low-sulfur oil	0.7% sulfur by weight oil (Existing Title V license, 40 CFR Part 60)	Combustion engineering	0.170 lb/MMBtu on a 90-day rolling average*(Existing Title V license; 06-096 CMR Chapter 145)

Alternatively, the NO_x limit from boilers #3 and #4 averaged shall be limited to 0.165 lbs/MMBtu on a 90-day operating rolling average

4. Lincoln Paper and Tissue, LLC

Lincoln Paper & Tissue (LPT) is an integrated kraft pulp and paper mill. Currently, LPT operates a hardwood digester and a softwood sawdust digester to produce pulp with approximately 50% recycled content. LPT uses one recovery boiler and a lime kiln in the recaust process for reclamation of the pulping chemicals. Also, LPT has three oil-fired boilers and one multi-fuel boiler to supply the mill with steam. The two paper machines produce specialty paper and the two tissue machines produce multi-ply dyed tissue. The pulp dryer machine produces bailed pulp which is either used by LPT or sold to other paper manufacturers.

At LPT, the only BART-eligible source is the Recovery Boiler #2, which is used to recover chemicals and produce steam. Emissions exit through two identical 175 foot stacks. The recovery boiler is a straight fire unit burning black liquor, typically without combustion support from fossil fuel. Normally, oil is used only during start-ups, shutdowns and to stabilize operation of the boiler.

The Recovery Boiler is exhausted to a wet bottom electrostatic precipitator (ESP) to control particulate emissions. This unit also serves to re-introduce salt cake into the black liquor which further concentrates the solids content.

<u>BART Analysis Summary</u>

The LPT BART analysis evaluated the best system of continuous emissions control technology available for each of the visibility-impairing pollutants (SO_2, PM, and NO_x). LPT's BART analysis submittal demonstrated that additional emission controls are neither feasible nor necessary for Recovery Boiler #2. PM emissions are controlled with the ESP to levels meeting compliance with MACT standards and therefore meet BART. SO_2 emissions are controlled by proper operation of the recovery boiler, including a three-level staged combustion air control system, and limitations on fuel oil use and sulfur content. NO_x emissions are minimized through staged combustion (having independently operating primary, secondary, and tertiary air dampers) and by the low nitrogen content of black liquor solids along with proper operation of the Recovery Boiler. Existing SO_2 and NO_x controls on the #2 Recovery Boiler were determined by the Department and EPA to meet BACT in the PSD/NSR licensing of the facility. As no new control technologies are available for further control of these pollutants from a recovery boiler the BACT determination constitutes BART compliance. Maine did not require additional visibility impact modeling because of the limited visibility impacts from this source.[43]

BART Determination

The Department determined BART for Lincoln Paper and Tissue as follows:

BART Determination for Lincoln Paper and Tissue

Unit	**PM**		**SO_2**		**NO_x**	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
Recovery Boiler	ESP	0.044 grains per dry standard cubic foot (0.044 gr/dscf) (Existing Title v license; 40 CFR Part 63)	Low-sulfur oil	141 ppmv (dry basis) @8% O_2 on a 24-hour block average basis (Existing Title v license)	Combustion engineering	233 ppmv (dry basis) @ 8% O_2 on a 24-hour block average basis (Existing Title v license)

5. SD Warren Company, Somerset

SD Warren Company (SDW) is an integrated kraft pulp and paper mill. Whole logs, chips, and biomass, are delivered to the mill by truck and/or train. The logs are sawn, debarked, chipped and stored in the mill's woodyard. The biomass is stored in piles and then conveyed to the boilers. The chips are stored in piles and then conveyed to the chip bin, chip steaming vessel, and then the digester. SDW operates one Kamyr continuous digester to produce pulp (hardwood, softwood, or any combination thereof), one recovery boiler and one lime kiln in the recaust process for reclamation of the pulping chemicals. There are two multi-fuel boilers and an oil fired package boiler to supply the mill with steam. SDW has three paper machines which produce paper. There are also two pulp machines. One pulp machine has a steam operated dryer and both machines produce

[43] Modeled visibility impacts attributable to Recovery Boiler #2 as 0.0073 deciviews (dv) for SO2, 0.0882 dv for NOx, 0.0322 dv for PM, and 0.12 dv total impacts.

bailed pulp. The mill also operates support facilities, including the wood yard, wastewater treatment plant, sludge presses, pulp and paper production labs, environmental labs, roll wrapping, shipping and receiving operations, and a landfill.

There are four emissions units that were determined to be BART eligible at this facility; the Recovery Boiler, Smelt Tanks #1 and #2, and the Lime Kiln. The Recovery Boiler was installed in 1975-1976. It is used to recover chemicals from spent pulping liquors and to produce steam for mill operations. The Recovery Boiler is licensed to fire black liquor (spent pulping liquor), residual (#6) fuel oil, distillate (#2) fuel oil, and used oil. The Recovery Boiler is also licensed to combust low volume-high concentration (LVHC) and high volume-low concentration (HVLC) gases produced at various points in the pulping process. The current black liquor firing rate is 5.1 million pounds per day of black liquor solids (BLS). The licensed maximum black liquor firing rate will become 5.5 million pounds per day of BLS after the boiler upgrade project is completed (scheduled for October 2010). The Recovery Boiler is subject to MACT standards for Chemical Recovery Combustion Sources at Kraft Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (40 CFR 63, Subpart MM).

SDW operates two smelt tanks which were installed in 1975-1976. The Smelt Tanks operate in conjunction with the Recovery Boiler. Recovered sodium-based pulping chemicals, in the form of molten salts, are discharged from the bottom of the Recovery Boiler into the Smelt Tanks, where they are mixed with a water/caustic solution to form green liquor. The Smelt Tanks are subject to MACT standards for Chemical Recovery Combustion Sources at Kraft Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (40 CFR 63, Subpart MM).

The Lime Kiln was installed in 1975-1976. It is used to convert lime mud (principally calcium carbonate) to lime (calcium oxide). Fuel is fired in the Lime Kiln to generate the heat that is needed to convert lime mud to lime. The Lime Kiln is licensed to fire residual (#6) fuel oil, distillate (#2) fuel oil, used oil, and propane. The Lime Kiln is also licensed to combust LVHC gases and foul condensate streams.

<u>BART Analysis Summary</u>

Recovery Boiler

PM: SDW currently operates a three-chamber electrostatic precipitator (ESP) on the Recovery Boiler. SDW identified the following available retrofit technologies for control of PM from Kraft mill recovery boilers: electrostatic precipitators, wet scrubbers, and fabric filters. Wet scrubbers were eliminated as a feasible control strategy because the ESP currently installed is capable of a greater degree of emissions control at a lower operating cost. Fabric filters are generally considered to be equivalent to ESPs in regards to pollution control. However, fabric filters have not been applied to recovery boilers at Kraft mills and have been eliminated as a feasible control alternative. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

SO_2: SDW's Recovery Boiler is currently equipped with a three-level staged combustion air control system and, after the upgrade project, will be equipped with a four-level staged combustion air system. SDW identified staged combustion systems and wet scrubbers as available retrofit technologies for control of SO_2 from Kraft mill recovery boilers. SO_2 emissions from recovery boilers occur due to the volatilization and subsequent oxidation of sulfur compounds that are present in the black liquor. Proper operation of the recovery boiler maximizes the conversion of sulfur compounds in the liquor to the principal constituents of the pulping chemicals. This occurs through capture of these sulfur compounds in the combustion zone of the boiler by sodium fume released from the smelt bed. Consequently, proper combustion control achieved through the use of staged combustion air systems results in effective control of SO_2 emissions. The only available alternative for SO_2 emission control is a wet scrubber. However, recovery boilers with a properly operated staged air combustion system operate at much lower concentrations of SO_2 in the flue gas than emission units to which wet scrubbers are routinely applied. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

NO_x: SDW's Recovery Boiler is currently equipped with a three-level staged combustion air control system and is in the process of upgrading with a four-level staged combustion air system. SDW identified the following available retrofit technologies for control of NO_x from Kraft mill recovery boilers: staged combustion systems, Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR), Low NO_x Burners, Flue Gas Recirculation, and Low-Temperature Oxidation. Emission controls which have been demonstrated on conventional steam boilers, including SNCR, SCR, flue gas recirculation, and low NO_x burners, cannot be applied to, or have not been demonstrated to be feasible on, Kraft mill recovery boilers. There has been some small-scale work done on "low-temperature oxidation" where pure oxygen is injected into the evaporation process to drive ammonia from the black liquor. However, the company currently looking into this technology has advised SDW that they are not aware of any commercial size case where this technology has been used. Therefore, this technology is not considered technically-feasible. There are no technically-feasible alternatives for control of NO_x emissions from recovery boilers other than proper operation of the boiler and the staged combustion control system. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

Smelt Tanks

PM: SDW currently operates a wetted fan scrubber on each of the smelt tanks for control of particulate emissions. The scrubbing media for the scrubbers is either water or weak wash from the white liquor clarification system. SDW identified the following available retrofit technologies for control of PM from smelt tanks: electrostatic precipitators, wet scrubbers, fabric filters, and mist eliminators. The most common PM emission control system employed on smelt tanks is wet scrubbers. The use of wet scrubbers also provides a secondary environmental benefit by controlling reduced sulfur compound emissions. The high moisture content of the smelt tank exhaust gases makes dry PM control systems, including fabric filters and dry ESPs, technically infeasible on this type of emission unit. The only remaining control technology, mist eliminators, provide a lower degree of PM emission control than the use of wet scrubbers. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

SO_2: Since no combustion takes place within smelt tanks, SO_2 is not generated within the emission unit. SDW was not able to identify any retrofit control technologies applicable to the control of SO_2 emissions from smelt tanks.

NO_x: Since no combustion takes place within smelt tanks, NO_x is not generated within the emission unit. SDW was not able to identify any retrofit control technologies applicable to the control of NO_x emissions from smelt tanks.

Lime Kiln

PM: Particulate emissions from the Lime Kiln are currently controlled by a variable throat venturi scrubber system followed by a cyclone separator. SDW identified the following available retrofit technologies for control of PM from lime kilns: electrostatic precipitators, wet scrubbers, and fabric filters. Fabric filters have never been applied to kraft pulp mill lime kilns. They are generally deemed to be technically infeasible on lime kilns. ESPs provide a greater degree of particulate matter control than venturi scrubbers. However, the possible annual reduction in emissions to be gained by replacing the existing scrubber with an ESP is relatively small (estimated at under 40 ton/year). Additionally, the scrubber also helps control emissions of SO_2 and reduced sulfur compounds. This beneficial removal of other pollutants is not available to lime kilns equipped with ESPs. Consequently, replacement of the existing scrubber with an ESP would be expected to result in higher TRS and SO_2 emissions from the Lime Kiln. With respect to any possible improvement in visibility impacts associated with retrofitting an ESP on the Lime Kiln, the modeling result for current PM emissions from the Lime Kiln was 0.0463 dv; well below the State's de minimis level of 0.1 dv. Therefore, any additional emission reductions that might be achieved by retrofitting the Lime Kiln with an ESP could only result in visibility impacts that would similarly be de minimis.

SO_2: SO_2 forms in the Lime Kiln from either the combustion of sulfur in the fuel or combustion of TRS compounds in the LVHC gases. Currently emissions of SO_2 are controlled by using a combination of the inherent sulfur removal provided by operation of the kiln itself (i.e. extensive contact between burner exhaust gases and the calcium compounds in the kiln) enhanced through the use of a venturi wet scrubber (post-combustion). SDW also uses a caustic scrubber (pre-combustion) on the LVHC gases fired in the boiler. Firing of LVHC gases in the Lime Kiln without pre-treatment with the caustic scrubber causes formation of rings within the Lime Kiln leading to excessive down-time of the equipment. Emissions of SO_2 from the Lime Kiln can vary significantly based on the amount of LVHC gases being fired and whether or not the

caustic scrubber is in operation. SDW identified the following available retrofit technologies for control of SO_2 from lime kilns: lime kiln operation and wet scrubbers. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

NO_x: NO_x emissions from the Lime Kiln are currently controlled by good combustion controls and operation of the unit's combustion air system. SDW identified the following available retrofit technologies for control of NO_x from lime kilns: Combustion Air Systems controls, SNCR, SCR, Low NO_x Burners, Flue Gas Recirculation. There are no technically feasible alternatives for control of NO_x from lime kilns beyond the measures currently employed. Low NO_x burner systems, which seek to reduce thermal NO_x formation through either combustion air or fuel staging, are not possible on the lime kilns because such systems negatively impact the efficiency, energy use, and calcining capacity of a lime kiln. Post combustion controls, such as SCR and SNCR, are not feasible for lime kilns. The temperature window necessary for the SNCR process (1500 – 2000 °F) is unavailable in a Kraft lime kiln. The high PM load at the exit of the kiln precludes the placement of the catalyst grid needed for the SCR process upstream of the PM control device, and the requisite temperature window required for this process (550 – 750 °F) is not available downstream of the PM control system. Since the controls already in place are considered the most stringent available, and these controls are already required by a federally enforceable condition, SDW was not required to perform the remaining steps of the control analysis.

<u>BART Determination</u>

BART Determination for SD Warren

Unit	**PM**		**SO_2**		**NO_x**	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
Recovery Boiler	ESP	0.030 gr/dry standard cubic foot (dscf) when all three ESP chambers are online and 0.038 gr/dscf when less than three chambers are online; 207 lb/hr (NSR License #A-19-77-2-A, 40 CFR Part 63, subpart MM)	Low-sulfur oil	100 ppmv (dry basis) @8% O_2 on a 24-hour block average basis (BART order) 1975lbs/hr (NSR License #A-19-77-2-A)	Combustion engineering	120 ppmv (dry basis) @ 8% O_2 on a 24-hour block average basis; 750 lb/hr (NSR License #A-19-77-2-A)

Smelt Tanks #1 and #2	Wet scrubber	26lb/hr; 0.2 lbs/ton BLS 40 CFR Part 63, subpart MM (Existing Title V license)	N/A	26lb/hr (Existing Title V license)	N/A	N/A
Lime Kiln	Wet scrubber	0.10 gr/dscf @10% O_2; 58 lb/hr (Existing Title V license; 40 CFR Part 63)	Wet scrubber	1.92 lb/MMBtu; 100 tons/year limit on a 12-month rolling average (Existing Title V license)	Staged Combustion	120 ppmvw @ @10% O_2 (Existing Title V license)

6. Verso Androscoggin

The Verso Androscoggin pulp mill produces bleached Kraft pulp and groundwood pulp. The bleached pulp is produced in two separate process lines, designated "A" and "B". Groundwood pulp is produced in another separate process line. Logs and wood chips are received in the Woodyard area, where they are stored and processed for eventual use in the Pulp Mill or Groundwood Mill. The Pulp Mill consists of two separate, parallel Kraft chemical pulping process lines. Pulp produced at the Verso Jay Mill is either used in the paper mill area or dried in the Flash Dryer for storage and/or sale.

The Paper Mill consists of all the equipment and operations used to convert pulp to paper, including stock preparation, additive preparation, coating preparation, starch handling, finishing, storage and paper machines. Non-condensable gases (NCGs) collected throughout the process from certain units in the Pulp Mill are sent to the Lime Kilns for combustion. The high-volume, low-concentration (HVLC) emission streams from certain other units are collected and sent to the Regenerative Thermal Oxidizer where they are incinerated. The Mill produces steam and electric power for mill operations with Power Boilers #1 and #2 and the Waste Fuel Incinerator (WFI).

There are ten BART-eligible units at Verso Jay: (1) Power Boiler #1; (2) Power Boiler #2; (3) Waste Fuel Incinerator; (4) Recovery Boilers # 1; (5) Recovery Boiler #2; (6) Smelt Tank #1; (7) Smelt Tank #2; (8) Lime Kiln A; (9) Lime Kiln B; and (10) Flash Dryer. Power Boilers #1 and #2 are each rated at 680 MMBtu/hr and began operation in 1965 and 1967, respectively. Power Boilers #1 and #2 are licensed to fire #6 fuel oil, #2 fuel oil, and used oil. The license currently limits the sulfur content of the fuel oil to no more than 1.8%, by weight. In addition, each boiler is equipped with low NO_x burners. The operation of the two boilers is related to whether or not and how the cogeneration plant (three natural gas fired turbines) at the Mill is operating. Typically when the cogeneration plant is operating, Power Boilers #1 and #2 do not operate. When the cogeneration plant is not operating, both boilers are operated, however, one boiler will typically carry the bulk of the load and the other boiler is idled or run at low load. There are occasions when both boilers operate at high load, but this is not a routine operating mode.

The Waste Fuel Incinerator (WFI) is rated at 480 MMBtu/hr on biomass and 240 MMBtu/hr on oil and began operation in 1976. While the WFI primarily fires biomass, fuel oils (#6 and #2 fuel oils, waste oil, and oily rags) can also be fired in the boiler. Sulfur dioxide and particulate matter emissions are controlled using a variable throat venturi scrubber and demister arrangement. When #6 fuel oil is fired in significant amounts, caustic is used in the wet scrubber to meet the applicable SO_2 emission limit. In addition, the WFI is equipped with a combustion system designed to ensure the optimal balance between control of NO_x and limitation of CO and VOC.

Recovery Boilers #1 and #2 generate steam while regenerating chemicals used in the wood pulping process, and began operation in 1965 and 1976, respectively. Recovery Boilers (#1 and #2) have rated processing capacities of 2.50 and 3.44 million pounds per day of dry black liquor solids (MMlb/day of BLS), respectively. Inorganic material (smelt) from the bottoms of the recovery boilers is used to produce green liquor, which is a solution of sodium sulfide and sodium carbonate salts, when it is dissolved in water or weak wash in the Smelt Dissolving Tanks (#1 and #2). Although the recovery boilers primarily fire black liquor, they also fire small quantities of #2 and #6 fuel oils during startup, shutdown, and load stabilization conditions. The license currently limits the sulfur content of the fuel oils to no more than 0.5%, by weight. Particulate matter emissions from both recovery boilers are currently controlled using an electrostatic precipitator (ESP).

Smelt Dissolving Tank #1 is rated at 2.50 MMlb/day of dry BLS and began operation in 1965. Smelt Dissolving Tank #2 is rated at 3.44 MMlb/day of dry BLS and began operation in 1975. Inorganic materials from the recovery boiler floors drain into Smelt Dissolving Tanks #1 and #2 as molten smelt. In the smelt dissolving tanks, the smelt is mixed with weak wash to form green liquor which is pumped to the causticizing area. Sulfur dioxide (SO_2) and particulate matter (PM_{10}) emissions from Smelt Dissolving Tank #1 are controlled with a dual-nozzle wet cyclonic scrubber which utilizes an alkaline scrubbing solution and was installed in 1983. Sulfur dioxide (SO_2) and particulate matter (PM_{10}) emissions from Smelt Dissolving Tank #2 are controlled with a triple-nozzle wet cyclonic scrubber which utilizes an alkaline scrubbing solution and was installed in 1976.

The "A" and "B" Lime Kilns process lime mud (calcium carbonate) from the causticizing area to regenerate calcium oxide (CaO). Inside the lime kilns, the lime mud is dried and heated to a high temperature where the lime mud is converted to lime (calcium oxide or CaO). "A" and "B" Lime Kilns are each rated at an operating rate of 248 tons of calcium oxide (CaO) per day and a heat input of 72 MMBtu/hr and began operation in 1965 and 1975, respectively. The lime kilns are licensed to fire #6 fuel oil, #2 fuel oil, propane, and used/waste oil. The license currently limits the sulfur content of the fuel oil to no more than 1.8%, by weight. The A and B Lime Kilns also serve as an incineration device (control device) for select sources of low volume high concentration (LVHC) non-condensable gases (NCG) from pulping operations at the mill. Particulate matter (PM_{10})

emissions are controlled from the "A" and "B" Lime Kilns using a fixed throat venturi scrubber.

The Flash Dryer is used to dry pulp for resale or for storage and future use on one of Verso Androscoggin's paper machines. The Flash Dryer has a rated heat input capacity of 84 MMBtu/hr and began operation in 1964. The flash dryer is licensed to fire #2 fuel oil, which contains a maximum sulfur content of 0.5% as defined by ASTM D396 standards. Particulate matter emissions are controlled using a wet shower system and SO_2 emissions are limited through the firing of #2 fuel oil.

BART Analysis Summary

Power Boilers #1 and #2:

PM: Verso did not identify or evaluate potential control technologies for the reduction of PM_{10} emissions from Power Boilers #1 and #2 because these units are subject to MACT Standards under section 112 of the CAA. In addition, Verso stated in their application that PM_{10} emissions are low based on the firing of fuel oil and that PM_{10} emissions from Power Boilers #1 and #2 have a minimal impact on visibility and a reduction in these emissions would have no impact on the contribution of either boiler to overall visibility impacts. Verso Androscoggin proposed that the final "Boiler MACT" standards (40 CFR Part 63, Subpart DDDDD) that the boilers are subject to will also represent BART for Power Boilers #1 and #2.

SO_2: Verso Androscoggin identified and evaluated low sulfur fuels, wet scrubbing, dry scrubbing, and semi-dry scrubbing as potential control technologies in the reduction of SO_2 emissions from Power Boilers #1 and #2. Low sulfur fuels and wet scrubbing control technologies were found to be technically feasible by Verso Androscoggin and so were evaluated further.[44] A summary of Verso Androscoggin's evaluation of the remaining viable SO_2 control technologies (low sulfur fuels and wet scrubbing) is provided in the table below.

The cost effectiveness numbers in the table below are based on controlling SO_2 emissions from Power Boilers #1 and #2 at the control effectiveness rates indicated in the table from the highest estimated two year average annual emissions between 2002 and 2008. In recent years (2008 and 2009) these boilers have been operating close to only 20% of the time, which for example, would result in an actual cost effectiveness of between \$4,920 and \$7,133 per ton of SO_2 removed with the installation of a wet scrubber. The use of low sulfur fuels or a wet scrubber has the potential to reduce visibility impacts from Power Boilers #1 and #2 by a perceptible amount; however there are significant cost differences among the three low sulfur containing fuels evaluated by Verso

[44] Dry and semi-dry scrubbing control technologies were evaluated, however Verso Androscoggin found that control effectiveness levels would be low (<25%), downstream particulate matter control devices such as an ESP and/or fabric filter would need to be installed to collect and re-circulate the scrubbing material, and no applications of these technologies on fuel oil fired boilers like Power Boilers #1 and #2 were identified during Verso Androscoggin's research of potential control technologies.

SO_2 BART Analysis Summary for Power Boilers #1 and #2

Control Technology	Control Effectiveness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Greatest Visibility Improvement
Natural Gas	99%	$3,334	Negligible	1.5
#2 Fuel Oil	97%	$3,341	Negligible	1.5
0.7% Sulfur #6 Fuel Oil	60%	$631	Negligible	0.9
0.7% Sulfur #6 Fuel Oil	60%	$631	Negligible	0.9
Wet Scrubbing	99%	$2,278	Disposal Impacts	1.5

Androscoggin and the wet scrubber. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that the use of 0.7% sulfur #6 fuel oil is a feasible and justifiable cost at $631 per ton of SO_2 reduced, but that the other low sulfur fuel options and the wet scrubbing option are not economically justifiable and do not represent BART. Therefore, Verso Androscoggin proposes that the use of lower sulfur (0.7%) #6 fuel oil in place of the higher sulfur (1.8%) #6 fuel oil currently fired, represents BART for control of SO_2 emissions from Power Boilers #1 and #2.

NO_x: Verso Androscoggin identified and evaluated selective catalytic reduction (SCR), low NO_x burners (LNBs), selective non-catalytic reduction (SNCR), and combustion control methods (including an overfire air (OFA) system and a flue gas recirculation (FGR) system) as potential control technologies in the reduction of NO_x emissions from Power Boilers #1 and #2. SCR and SNCR control technologies were found to be technically feasible and so were evaluated further. LNBs are currently installed and used on Power Boilers #1 and #2, and are estimated to provide a 15% reduction in NO_x emissions, so were not evaluated further. Combustion control methods were evaluated, however none were found to be viable control options for Power Boilers #1 and #2. Verso Androscoggin found that the size and design of Power Boilers #1 and #2 would provide little room for the installation of an overfire air system and that the application of a flue gas recirculation system would result in minimal reductions (7% to 15%) in NO_x emissions. A summary of Verso Androscoggin's evaluation of the remaining viable NO_x control technologies (SCR and SNCR) is provided in the table below.

Control Technology	Control Effectiveness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Greatest Visibility Improvement
SCR	90%	$5,271	Minor Impacts	1.7
SNCR	35%	$5,973	Minor Impacts	1.4

The cost effectiveness numbers in the table above are based on controlling NO_x emissions from Power Boilers #1 and #2 at the control effectiveness rates indicated in the table from the highest estimated two year average annual emissions between 2002 and 2008. In recent years (2008 and 2009) these boilers have been operating close to only 20% of the time, which for example, would result in an actual cost effectiveness of $16,313 per ton of NO_x removed with the installation of SCR. Although the use of SCR or SNCR has the potential to reduce visibility impacts by a perceptible amount, Verso Androscoggin proposes that the cost effectiveness levels are not economically justifiable based on the limited use of Power Boilers #1 and #2. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that the current use of LNBs represents BART for control of NO_x emissions from Power Boilers #1 and #2 and that no additional level of control is justifiable as BART.

Waste Fuel Incinerator Boiler:

PM: Verso Androscoggin did not identify or evaluate potential control technologies for the reduction of PM_{10} emissions from the Waste Fuel Incinerator Boiler (WFI) because this unit is subject to MACT Standards under section 112 of the CAA. Verso Androscoggin proposed that the final "Boiler MACT" standards (40 CFR Part 63, Subpart DDDDD) that the WFI is subject to will also represent BART for the WFI.

SO_2: Verso Androscoggin identified and evaluated low sulfur fuels, wet scrubbing, dry scrubbing, and semi-dry scrubbing as potential control technologies in the reduction of SO_2 emissions from the WFI. While using low sulfur fuels is technically feasible, Verso Androscoggin believes that it is not a practically feasible option for the WFI based on the limited amount of fuel oil typically used in the boiler (less than 10% of the annual fuel oil heat input capacity). The WFI currently uses a water based wet scrubbing system for PM control with the addition of caustic to meet SO_2 emission limits when firing #6 fuel oil in significant amounts. Dry and semi-dry scrubbing control technologies were not considered by Verso Androscoggin to be either practical or technically feasible for the WFI due to the fact that they could not find any applications of these technologies on any other biomass-fired grate type boilers like the WFI. Verso Androscoggin also believes that the cost of removing the existing wet scrubber and replacing it with a dry or semi-dry scrubbing system and a new ESP and/or fabric filter would be costly. A summary of Verso Androscoggin's evaluation of the only remaining viable SO_2 control technology (adding caustic to the existing wet scrubbing system) is provided in the table below.

SO_2 BART Analysis Summary for the Waste Fuel Incinerator

Control Technology	Control Effectiveness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Greatest Visibility Improvement
Addition of Caustic to Existing Wet Scrubber	50%	$21,800	Disposal Impacts	<0.1

The WFI has very low baseline SO_2 emissions (~50 tons per year) due to the inherent low sulfur content and alkalinity of the primary fuel (biomass) and the small amount of fuel oil used in the WFI. In addition, during the limited amount of time that #6 fuel oil is used to provide a significant portion of the heat input to the WFI, caustic is added to the wet scrubber to control SO_2 emissions. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that additional control of SO_2 emissions from the WFI cannot be justified as BART due to the imperceptible effect it would have on visibility.

NO_x: Verso Androscoggin identified and evaluated selective catalytic reduction (SCR), low NO_x burners (LNB), selective non-catalytic reduction (SNCR), and combustion control methods (including an overfire air system and a flue gas recirculation system) as potential control technologies in the reduction of NO_x emissions from the WFI. SCR and SNCR control technologies were found to be technically feasible and so were evaluated further. Since the WFI primarily fires biomass on the grate, LNBs would not be effective for the majority of the time that the WFI operates, thus Verso Androscoggin felt LNBs did not warrant further evaluation. Combustion control methods were evaluated, however none were found to be viable control options for the WFI due to the limited NO_x removal potential (<15%), potential impacts to other pollutants and boiler equipment, and the limited amount of room available for the installation of control equipment. A summary of Verso Androscoggin's evaluation of technically feasible NO_x control technologies (SCR, SNCR, and FGR) is provided in the table below.

Control Technology	Control Effectiveness	Cost Effectiveness ($/ton removed)	Energy and Other Impacts	Greatest Visibility Improvement
SCR	90%	$4,676	Minor Impacts	0.3
SNCR	30%	$5,944	Minor Impacts	0.1
FGR	15%	$17,010	Minor Energy Impacts	<0.1

Although the use of SCR has the potential to reduce visibility impacts by a perceptible amount, Verso Androscoggin proposes that the cost effectiveness levels are not economically justifiable for any of the control technologies evaluated, including SCR. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that additional control of NO_x emissions from the WFI cannot be justified as BART due to the capital costs ($3 million to more than $7.6 million) and cost effectiveness levels ($4,700 to more than $17,000 per ton of NO_x removed).

Recovery Boilers #1 and #2

PM: Particulate matter (PM) emissions from Recovery Boilers #1 and #2 are currently controlled by an existing shared/common electrostatic precipitator (ESP). Verso Androscoggin did not identify or evaluate potential control technologies for the reduction of PM_{10} emissions from Recovery Boilers #1 and #2 because these units are subject to MACT Standards under section 112 of the CAA. Recovery Boilers #1 and #2 are subject to MACT standards pursuant to 40 CFR Part 63, Subpart MM (MACT II). Verso Androscoggin reviewed the RACT/BACT/LAER Clearinghouse (RBLC) and believes that the current control configuration is the most current control technology in use on recovery boilers and that there are no new technologies subsequent to the MACT standard that should be considered. Based on this information, Verso Androscoggin proposed in its BART analysis that it was not necessary to expand the BART analysis for PM_{10} and therefore did not identify or evaluate potential control technologies for the additional reduction of PM_{10} emissions from Recovery Boilers #1 and #2. Verso Androscoggin proposes that "MACT II" standards (40 CFR Part 63, Subpart MM) that the boilers are currently subject to represent BART for PM_{10} emissions from Recovery Boilers #1 and #2.

SO_2: Verso Androscoggin has found that sulfur dioxide (SO_2) emissions from Recovery Boilers #1 and #2 are variable due to several factors including black liquor properties (e.g., sulfidity, sulfur to sodium ratio, heat value, and solids content), combustion air, liquor firing patterns, furnace design features, and type of startup fuel used. Both recovery boilers are low-odor design. Although each recovery boiler has the ability to utilize #2 fuel oil, #6 fuel oil, and used/waste oil for startup, shutdown, and load stabilizing conditions, fuel oil firing is not a typical operating scenario for the recovery boilers. SO_2 emission levels during fuel oil firing conditions are directly related to the sulfur content of the fuel oils. Black liquor solids (BLS) firing produces sodium fume, which effectively scrubs SO_2 emissions. Verso Androscoggin identified and evaluated wet scrubbing, dry scrubbing, and semi-dry scrubbing as potential control technologies in the reduction of SO_2 emissions from Recovery Boilers #1 and #2, however none of these technologies were found to have been applied to recovery boilers and Verso Androscoggin believes that operation of these technologies could negatively affect the operation of Recovery Boilers #1 and #2. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that each of the control technologies evaluated are not technically feasible and therefore were not evaluated further. Verso Androscoggin proposes that existing combustion controls represent BART for the control of SO_2 emissions from Recovery Boilers #1 and #2.

NO_x: Kraft recovery boilers are a unique type of combustion source that inherently produce low levels of NO_x emissions. Most of the NO_x emissions produced by recovery boilers can be attributed to fuel based NO_x resulting from the partial oxidation of the nitrogen contained in the black liquor. Both Recovery Boilers (#1 and #2) operate with a reducing zone in the lower part of the boiler and an oxidizing zone in the region of the liquor spray guns designed to provide secondary and tertiary staged combustion zones to complete combustion of the black liquor and minimize NO_x emissions.

Verso Androscoggin identified and evaluated selective catalytic reduction (SCR), low NO_x burners (LNB), selective non-catalytic reduction (SNCR), and combustion control methods (including the addition of a fourth level or quaternary air system and a flue gas recirculation system) as potential control technologies in the reduction of NO_x emissions from Recovery Boilers #1 and #2. SCR has not been applied or demonstrated successfully on any recovery boilers according to Verso Androscoggin and they do not know how the unique characteristics of recovery boiler exhaust gas constituents would react with a SCR catalyst, so they did not further evaluate this control technology. Verso Androscoggin's evaluation of LNB technology is that it is not feasible to use this technology in the firing of black liquor given its tar-like qualities and the method by which it is injected into the boiler and that it would have minimal results in the firing of fuel oils given the small amounts of fuel oils that are fired in the recovery boilers. Verso Androscoggin's evaluation of SNCR control technologies resulted in a finding that there have been no applications of this technology on recovery boilers in the United States for a variety of reasons, including safety concerns associated with the risk of a smelt/water explosion should boiler tube walls corrode and leak near urea injection points and risks associated with an ammonia handling system for the SNCR. Operational concerns associated with SNCR were found to include the potential formation of acidic sulfates that could result in corrosion and a catastrophic boiler tube failure. As a result of Verso Androscoggin's initial evaluation of SNCR, no further evaluation was conducted. Recovery Boilers #1 and #2 are currently designed and operated using low excess air combined with three levels of staged combustion to minimize NO_x emissions. Additional combustion control methods were evaluated by Verso Androscoggin, however none were found to be viable control options for Recovery Boilers #1 and #2 due to the limited amount of space in the boilers to install a fourth or quaternary air system and due to the technical challenges re-circulating recovery boiler exhaust gases in a FGR system due to the unique characteristics of the exhaust gases. Based on Verso Androscoggin's identification and evaluation of control technology options, they proposed that the existing combustion control methods represent BART and that additional control of NO_x emissions from Recovery Boilers #1 and #2 are not technically feasible and warrant no further evaluation.

Smelt Tanks #1 and #2

PM: Particulate matter (PM) emissions from Smelt Dissolving Tanks #1 and #2 are currently controlled by existing wet cyclonic scrubbers. Verso Androscoggin did not identify or evaluate other potential control technologies for the reduction of PM_{10} emissions from Smelt Dissolving Tanks #1 and #2 because these units are subject to MACT Standards under section 112 of the CAA. Smelt Dissolving Tanks #1 and #2 are subject to MACT standards under 40 CFR Part 63, Subpart MM (MACT II). Verso Androscoggin reviewed the RACT/BACT/LAER Clearinghouse (RBLC) and believes that the current control configuration is the most current control technology in use on smelt dissolving tanks and that there are no new technologies subsequent to the MACT standard that should be considered. Verso Androscoggin proposes that "MACT II" standards (40 CFR Part 63, Subpart MM) that the smelt dissolving tanks are currently subject to represent BART for PM_{10} emissions from Smelt Dissolving Tanks #1 and #2.

SO_2: Verso Androscoggin has found that sulfur dioxide (SO_2) emissions from Smelt Dissolving Tanks #1 and #2 are dependent on how much sulfur carries over from the respective recovery boilers with the smelt. Controlled smelt-water explosions in the smelt dissolving tanks can create SO_2 as a result of the oxidation of the sulfur in the smelt. SO_2 emissions from both smelt dissolving tanks combined are very low at approximately 5 tons per year. Verso Androscoggin proposes that BART for SO_2 emissions from Smelt Dissolving Tanks #1 and #2 is no additional control based on the

following: (1) SO_2 emissions from the smelt dissolving tanks during the BART baseline period were and are expected to continue to be extremely low (~5 TPY, combined); (2) the smelt dissolving tanks and associated scrubbers are designed and operated to minimize SO_2 emissions; (3) SO_2 emissions from the smelt dissolving tanks have a minimal impact on visibility (<0.1 deciviews); and (4)additional control of SO_2 emissions from the smelt dissolving tanks would have a minimal impact on overall visibility.

NO_x: Smelt Tanks #1 and #2 do not emit NO_x.

Lime Kilns A and B

PM: Particulate matter (PM_{10}) emissions from the "A" and "B" Lime Kilns consist primarily of dust entrained from the combustion section of the kilns. This dust consists of sodium salts, calcium carbonate, and calcium oxide. PM_{10} emissions are currently controlled by existing venturi scrubbers. These units are also subject to MACT Standards under section 112 of the CAA, and 40 CFR Part 63, Subpart MM (MACT II). Verso Androscoggin reviewed the RACT/BACT/LAER Clearinghouse (RBLC) and believes that there are two control technologies that represent the most stringent PM control (ESPs and venturi scrubbers). Both ESPs and venturi scrubbers have been used to control PM emissions from lime kilns and both are capable of a high level of control. Verso Androscoggin proposes that use of the existing venturi scrubbers to control PM_{10} emissions from the "A" and "B" represents BART for the following reasons: (1) the existing venturi scrubbers maintain compliance with the MACT II PM emission limits; (2) the replacement of the existing venturi scrubbers with dry ESPs could increase SO_2 emissions from the lime kilns when compared to use of the venturi scrubbers; (3) the replacement of the existing venturi scrubbers with wet ESPs would result in high capital costs ($1.5 million per kiln); and (4)visibility impacts from the lime kilns are minimal and installation of additional control would result in inconsequential improvement in visibility.

SO_2: Verso Androscoggin has found that a significant portion of the sulfur dioxide (SO_2) formed during the combustion process in the lime kilns is removed as the regenerated quicklime in the kilns functions as a scrubbing agent. In addition, the NCG collection system is equipped with a scrubber that uses white liquor (sodium hydroxide or NaOH) and thus the sulfur loading from the NCGs is minimized. SO_2 emissions from both lime kilns combined are very low at less than 4 tons per year primarily due to the alkalinity of the lime. Verso Androscoggin proposes that BART for SO_2 emissions from the "A" and "B" Lime Kilns is no additional control based on the following: (1) SO_2 emissions from the lime kilns during the BART baseline period were and are expected to continue to be extremely low (<4 TPY, combined); (2) there are no control technologies available for lime kilns that are more cost effective than the inherent scrubbing that occurs for SO_2 due to the alkalinity of the lime in the process; (3) SO_2 emissions from the smelt dissolving tanks have a minimal impact on visibility (<0.1 deciviews); and (4)additional control of SO_2 emissions from the lime kilns would have a minimal impact on overall visibility.

NOx: Verso Androscoggin identified and evaluated selective catalytic reduction (SCR), low NO_x burners (LNB), and selective non-catalytic reduction (SNCR) as potential NOx control technologies. Verso Androscoggin's evaluation of SCR and SNCR as potential NO_x control technologies revealed that they have not been installed on any lime kilns in the pulp and paper industry, and were also found to be technically infeasible, so were not evaluated further. Verso Androscoggin's research with respect to lime kilns and LNB technology revealed that the technology is actually a combination of passive combustion control measures used to minimize NO_x formation primarily from thermal NO_x and to a lesser extent fuel NO_x. These combustion control measures include careful design of the fuel feed system in order to ensure proper mixing of the fuel with air and burner "tuning" or optimization which impacts fuel burning efficiency and overall flame length. Verso Androscoggin already incorporates burner "tuning" in the operation and maintenance of the "A" and "B" Lime Kilns to optimize the relationship between NO_x emissions and operating efficiency. Based on Verso Androscoggin's identification and evaluation of control technology options, they propose that the current use of LNB (referred to as combustion control measures on lime kilns) represents BART for control of NO_x emissions from "A" and "B" Lime Kilns and that no additional level of control is technically feasible. Verso Androscoggin also notes in their BART analysis that existing NO_x emissions from the "A" and "B" Lime Kilns have a minimal impact on visibility (<0.1 deciviews) and that additional control of NO_x emissions would have a minimal impact on the overall improvement to visibility.

Flash Dryer

PM: Particulate matter (PM_{10}) emissions from the Flash Dryer are currently controlled by the use of a wet shower system. Verso Androscoggin proposes that the application of add-on controls and the use of cleaner fuels are not practical considerations for controlling PM emissions from the Flash Dryers and that with potential visibility impacts from the Flash Dryer being extremely low, any emission reductions would have an inconsequential impact on visibility improvement.

SO_2: The Flash Dryer is limited to firing #2 fuel oil with a maximum sulfur content of 0.5%, by weight and so has relatively low SO_2 emissions. Although Verso Androscoggin could replace the use of #2 fuel oil with lower sulfur containing fuels such as low sulfur (0.05%) diesel fuel or natural gas, the Flash Dryer is predicted to have peak visibility impacts of 0.1 deciviews or less. Based on Verso Androscoggin's identification and evaluation of SO_2 control technology options for the Flash Dryer, they propose that no additional level of control is representative of BART.

NO_x: The Flash Dryer is not equipped with any NO_x control equipment. NO_x emissions from the Flash Dryer are primarily generated from the nitrogen component in the fuel oil. Verso Androscoggin currently uses good maintenance practices to minimize NO_x emissions from the Flash Dryer. Verso Androscoggin's investigation of conventional NO_x combustion controls (e.g., LNB, OFA, and FGR) lead to findings that they are either unavailable for installation on the Flash Dryer or are not feasible for a combustion source as small as the Flash Dryer.

BART Determinations:

BART Determination for VERSO Androscoggin

Unit	PM		SO_2		NO_x	
	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference	Control Type	Emission Limit and Reference
Power Boilers #1 and #2	Low sulfur oil/ combustion control	Compliance with 40 CFR Part 63 Subpart DDDD	Low sulfur fuel	Low sulfur fuel oil containing no more than 0.7 % sulfur, by weight. (BART order)	Low NO_x burners	0.447 lbs/MMBtu on a 24-hour block average basis (Existing Title V license)
Waste Fuel Incinerator	Combustion controls, wet scrubber	Compliance with 40 CFR Part 63 Subpart DDDD	Wet scrubber	0.8 lbs/MMBtu on a 3-hour average (Existing Title V license)	Combustion controls	0.4 lbs/ MMBtu on a 24-hour block average basis (Existing Title V license)
Recovery Boiler #1	ESP	Compliance with 40 CFR Part 63 Subpart MM	Staged air combustion	120 ppmdv @8% O_2 on a 30-day rolling average basis when operating at a black liquor recover rate of 50% or higher. SO2 emissions shall not exceed 140 ppmdv @8% O_2 on a 30-day rolling average basis when operating at a black liquor recover rate of less than 50% (BART order)	Combustion controls (NSR)	150 ppmdv, when corrected to 8% % O_2 on a 24-hour block average basis (BART order)
Recovery Boiler #2	ESP	Compliance with 40 CFR Part 63 Subpart MM (Existing Title V license)	Staged air combustion	120 ppmdv @8% O_2 on a 30-day rolling average basis (Existing Title V license)	Combustion controls (RACT)	206 ppm corrected to 8% % O_2 on a 24-hour block average basis (Existing Title V license)

Smelt Tanks #1 and #2	Wet cyclonic scrubber	Compliance with 40 CFR Part 63 Subpart MM (Existing Title V license)	Wet cyclonic scrubber	Smelt Tank #1- 2.7 lbs/hr Smelt Tank #2- 3.9 lbs/hr (Existing Title V license)	N/A	N/A
Lime Kilns A and B	Venturi scubber	Compliance with 40 CFR Part 63 Subpart MM	Venturi scubber	6.7 Lbs/hr, 74.6 tpy (Existing Title V license)	Combustion controls (RACT)	120 ppm @ 10% O_2 (stack test) (Existing Title V license)
Flash Dryer	Wet shower	5 lbs/hr (Existing Title V license)	Low sulfur fuel (#2 oil)	Low sulfur fuel oil containing no more than 0.5 % sulfur, by weight (Existing Title V license)	Good combustion practices (Existing Title V license)	11.8 lbs/hr

10.8 Schedule for BART Implementation

As provided in 40 CFR Section 51.308(e)(1)(iv) BART must be in operation for each applicable source no later than five years after SIP/TIP approval. Pursuant to 38 M.R.S.A. §603-A, sub-§8 (b), the State of Maine is requiring that each source subject to BART shall install and operate BART as expeditiously as practicable but in no event later than January 1, 2013.

As provided in 40 CFR Section 51.308(e)(1)(v) the Title V operating permits for BART sources must include a requirement that each source maintain the control equipment and establish procedures to ensure such equipment is properly operated and maintained. This requirement will be included in the Title V operating permit for each source subject to BART. The BART requirements for Maine Bart eligible sources will be federally enforceable through the Title V operating permit program and through incorporation in the Maine Regional Haze SIP.

Copies of the draft Title V operating permits for each source are included in Attachment M

11. Reasonable Progress Goals

The Regional Haze Rule (40 CFR Section 51.308 (d)(1)) requires each state with Class I areas to establish reasonable progress goals providing for reasonable progress towards achieving natural visibility in each Class I area. In addition, EPA released guidance on June 7, 2007 to use in setting reasonable progress goals. The goals must provide improvement in visibility for the most impaired days, and ensure no degradation in visibility for the least impaired days over the State Implementation Plan (SIP) period. The State of Maine must also provide an assessment of the number of years it would take to attain natural visibility conditions if improvement continues at the rate represented by the reasonable progress goal.

Under 40 CFR Section 51.308 (d)(1)(iv), consultation is required in developing reasonable progress goals. The rule states:

> *In developing each reasonable progress goal, the State must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area. In any situation in which the State cannot agree with another such State or group of States that a goal provides for reasonable progress, the State must describe in its submittal the actions taken to resolve the disagreement. In reviewing the State's implementation plan submittal, the Administrator will take this information into account in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions.*

As discussed in Section 3, Maine consulted with states that contribute to visibility impairment at its Class I areas and with states that requested consultation with Maine regarding their Class I areas (New Hampshire, Vermont and New Jersey). Maine worked closely with these states during the consultation process and agrees with the reasonable progress goals established by New Hampshire, Vermont and New Jersey.

In developing the reasonable progress goals the Class I state must also consider four factors (cost, time needed, energy & non-air quality environmental impacts, and remaining useful life). The state also must show that it considered the uniform rate of improvement and the emission reduction measures needed to achieve it for the period covered by the implementation plan, and if the state proposes a rate of progress slower than the uniform rate of progress, assess the number of years it would take to attain natural conditions if visibility improvement continues at the rate proposed.

11.1 Calculation of Uniform Rate of Progress

As a benchmark to aid in developing reasonable progress goals, MANE-VU compared the baseline visibility conditions to natural visibility condition at each Class I area. The difference between baseline and natural visibility conditions at each MANE-VU Class I area was used to determine the uniform rate of progress that would be needed during each implementation period in order to attain natural visibility. Table 11-1 presents baseline visibility, natural visibility and required uniform rate of progress for each MANE-VU Class I area. Visibility values are expressed in deciviews (dv) where a single-unit decrease would represent a barely perceptible improvement in visibility.

Table 11-1
Uniform Rate of Progress Calculation
(all values in deciviews)

Class I Area	(2000-2004) Baseline Visibility (deciviews) (20% Worst Days)	Natural Visibility Conditions (20% Worst Days)	Deciview Improvement Needed by 2018	Total Deciview Improvement Needed by 2064	Uniform Rate of Improvement Annually
Acadia National Park	22.9	12.4	2.4	10.5	0.174
Roosevelt/Campobello International Park	21.7	12.0	2.3	9.7	0.162
Moosehorn Wilderness Area	21.7	12.0	2.3	9.7	0.162
Presidential Range/Dry River Wilderness Area	22.8	12.0	2.5	10.8	0.180
Great Gulf Wilderness Area	22.8	12.0	2.5	10.8	0.180
Lye Brook Wilderness	24.5	11.7	3.0	12.8	0.212
Brigantine Wilderness	29.0	12.2	3.9	16.8	0.280

Note: Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee.[45]

The reasonable progress goals established for the Maine Class I areas are expected to provide greater visibility improvements than the uniform rate of progress shown in Table 11-1, above.

11.2 Reasonable Progress Goals for Class I Areas in Maine

In accordance with the requirements of 40 CFR Section 51.308 (d)(1), this Regional Haze SIP establishes reasonable progress goals (RPG) for each Class I area in Maine for the period of the implementation plan.

40 CFR Section 51.308(d)(1)(vi) requires that reasonable progress goals represent at least the visibility improvement expected from implementation of other Clean Air Act programs during the applicable planning period. As documented in Section 8 Emissions

[45] "Baseline and Natural Visibility Conditions, Considerations and Proposed Approach to the Calculation of Baseline and Natural Visibility Conditions at MANE-VU Class I Areas," NESCAUM, December 2006.

Inventory, and Section 12 Long-Term Strategy, the modeling that formed the basis for reasonable progress goals in MANE-VU Class I areas included estimation of the effects of all other programs required by the Clean Air Act. Further information may be found in those sections of this SIP and in the documentation for the MANE-VU modeling.

Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee. Progress toward the 2018 target will be calculated based on 5-year averages calculated in a nationally consistent manner consistent with EPA's "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA-454/B-03-004, September 2003) as updated by the alternative method for calculating regional haze recommended by the IMPROVE Steering Committee.

To determine the RPG in deciviews, MANE-VU conducted modeling with certain control measure assumptions. The control measures reflected in these reasonable progress goals are summarized below. In establishing its reasonable progress goals for 2018, Maine recognizes that contributing states have the flexibility to submit SIP revisions between now and 2018 as they are able to adopt control measures to implement these goals. This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective SO_2, NO_x and PM control measures.

Tables 11-2 and 11-3 below, provide a summary of the Reasonable Progress Goals for Maine Class I areas.

Table 11-2
Reasonable Progress Goals—20% Worst Days
(all values in deciviews)

Class I Area	**Baseline Visibility (deciviews) (20% Worst Days 2000-2004)**	**Reasonable Progress Goals, 20% Worst Days (expected deciview level by 2018)**	**Deciview Improvement Expected by 2018**	**Natural Visibility Conditions (20% Worst Days)**
Acadia National Park	22.9	19.4	3.5	12.4
Moosehorn Wilderness Area/ Roosevelt Campobello International Park	21.7	19.0	2.7	12.0

Table 11-3
Reasonable Progress Goals—20% Best Days
(all values in deciviews)

Class I Area	Baseline Visibility (deciviews) (20% Best Days)	Reasonable Progress Goals, 20% Best Days (expected deciview level by 2018)	Deciview Improvement Expected by 2018	Natural Visibility (20% Best Days) (deciviews)
Acadia National Park	8.8	8.3	0.5	4.7
Moosehorn Wilderness Area/ Roosevelt Campobello International Park	9.2	8.6	0.6	5.0

11.3 Identification of Additional Reasonable Controls

Maine and the other MANE-VU states have identified specific emission control measures- beyond those which individual states or RPOs have already made commitments to implement- that would be reasonable to undertake as part of a concerted strategy to mitigate regional haze. The proposed additional control measures were incorporated into the regional strategy adopted by MANE-VU on June 20, 2007, to meet the reasonable progress goals established in this SIP. The basic elements of this strategy are described in the MANE-VU "Ask" (see Subsection 3.4). States targeted for coordinated actions toward achieving these goals include all of the MANE-VU states plus Georgia, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, South Carolina, Tennessee, Virginia and West Virginia[46] .

In addition to proposed emission controls in the U.S., the MANE-VU Class I states determined that it was reasonable to include anticipated emission reductions in Canada in the modeling used to set reasonable progress goals. This determination was based on evaluations conducted before and during the consultation process (see description of relevant consultations in Subsection 3.3). Specifically, the modeling accounts for six coal-burning EGUs in Canada having a combined output of 6,500 MW that are scheduled to be shut down and replaced by nine natural gas turbine units with selective catalytic reduction (SCR) by 2018.

The process of identifying reasonable progress measures and setting reasonable progress goals is described in the subsections which follow. Further elaboration on the reasonable progress measures which make up the Maine/MANE-VU long-term strategy is provided

[46] In addition, the State of Vermont identified at least one source in the State of Wisconsin as a significant contributor to visibility impairment at the Lye Brook Wilderness Class I Area.

in Section 12 of this SIP. Under this plan, the affected states will have a maximum of 10 years to implement reasonable and cost-effective control measures to reduce primarily SO_2 and NO_x emissions. For a description of how proposed emission control measures were modeled to estimate resulting visibility improvements, see Subsection 11.5, Visibility Effects of Additional Control Measures.

11.4 The Foundations for Determining Reasonable Controls

40 CFR Section (d)(1)(i)(A) of EPA's Clean Air Visibility Rule requires that, in establishing reasonable progress goals for each Class I area, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. The SIP must include a demonstration showing how these factors were taken into consideration in setting the reasonable progress goals. These factors are sometimes termed the "four statutory factors," since their consideration is required by the Clean Air Act.

Focus on SO_2: MANE-VU conducted a Contribution Assessment (Attachment A) and developed a conceptual model that indicated particulate sulfate formed from emissions of SO_2 was the dominant contributor to visibility impairment at all sites and during all seasons in the base year. While other pollutants, including organic carbon and NO_x, will need to be addressed in order to achieve the national visibility goals, MANE-VU's contribution assessment suggested that an early emphasis on SO_2 will yield the greatest near-term benefit. Therefore, it is reasonable to conclude that the additional measures considered in establishing reasonable progress goals require reductions in SO2 emissions.

Contributing Sources: The MANE-VU Contribution Assessment indicates that emissions in 2002 from within the MANE-VU region were responsible for about 25 to 30 percent of the sulfate at MANE-VU Class I areas. Sources in the Midwest and Southeast regions were responsible for about 15 to 25 percent each, respectively. Point sources dominated the inventory of SO_2 emissions. Therefore, the MANE-VU's long-term strategy, includes additional measures to control sources of SO_2 both within the MANE-VU region and in other states that were determined to contribute to regional haze at MANE-VU Class I areas.

The Contribution Assessment documented the source categories most responsible for visibility degradation at MANE-VU Class I areas. As described in the Section 12, Long Term Strategy, there was a collaborative effort between the Ozone Transport Commission and MANE-VU to evaluate a large number of potential control measures. Several measures that would reduce SO_2 emissions were identified for further study.

These efforts led MANE-VU to prepare the report entitled, "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas" MACTEC, July 9, 2007 otherwise known as the Reasonable Progress Report (Attachment T), which documented an analysis of the four statutory factors for five major source categories. Table 11-4 summarizes the results of MANE-VU's Reasonable Progress Report, which considered EGUs, ICI boilers, cement kilns, heating oil and residential wood combustion.

Table 11-4
Summary of Results from the Four Factor Analysis

Source Category	Primary Regional Haze Pollutant	Control Measure(s)	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	Switch to a low sulfur coal (generally <1% sulfur), switch to natural gas (virtually 0% sulfur), coal cleaning, Flue Gas Desulfurization (FGD)-Wet, -Spray Dry, or -Dry.	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	Switch to a low sulfur coal (generally <1% sulfur), switch to natural gas (virtually 0% sulfur), switch to a lower sulfur oil, coal cleaning, combustion control, Flue Gas Desulfurization (FGD) - Wet, -Spray Dry, or -Dry.	$130-$11,000 based on available literature. Depends on size.	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	Fuel switching, Dry Flue Gas Desulfurization-Spray Dryer Absorption (FGD), Wet Flue Gas Desulfurization (FGD), Advanced Flue Gas Desulfurization (FGD).	$1,900-$73,000 based on available literature. Depends on size.	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	Lower the sulfur content in the fuel. Depends on the state.	$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	State implementation of NSPS, Ban on resale of uncertified devices, installer training certification or inspection program, pellet stoves, EPA Phase II certified RWC devices, retrofit requirement, accelerated changeover requirement, and accelerated changeover inducement.	$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® CAIR versus CAIR plus analysis conducted for MARAMA/MANE-VU by ICF.

The MANE-VU states reviewed the four-factor analysis presented in the Reasonable Progress Report, consulted with each other about the measures, and concluded by adopting the statements known as the MANE-VU Ask on June 20, 2007. These statements identify the control measures that would be pursued toward improving visibility in the region. The following discussion focuses on the four basic control strategies chosen by MANE-VU and included in the modeling used to establish reasonable progress goals: BART, emissions reductions from specific EGUs, low sulfur fuel oil requirements, and additional measures determined to be reasonable.

11.4.1 Best Available Retrofit Technology (BART) Controls

The MANE-VU states have identified approximately 100 BART-eligible sources in the region. Most of these facilities are already controlling emissions in response to other federal or state air programs, or are likely to install emission controls under new programs. Previously, EPA determined that CAIR fulfilled the BART requirement for all EGUs in CAIR-affected states. Although CAIR has been remanded to EPA, the determination that CAIR is equivalent to BART is still in place. Maine anticipates that those same units will be covered by successor legislation or new rulemaking undertaken in response to the CAIR remand. A complete compilation of BART-eligible sources in the MANE-VU region is available in Attachment A of MANE-VU's "Assessment of Control Technology Options for BART-Eligible Sources," March 2005 (Attachment R).

To assess the benefits of implementing BART in the MANE-VU region, NESCAUM estimated reductions for twelve BART-eligible units in the MANE-VU states that would probably be controlled as a result of BART requirements alone. These sources include one EGU and eleven non-EGUs. The affected units were identified by staff members in each MANE-VU state, who then furnished data on potential control technologies and expected emission levels for these units under BART implementation. The twelve sources are listed in Table 11-5, along with their 2002 baseline and 2018 projected emissions. Information on these units was incorporated into the 2018 emissions inventory projections that were used to establish reasonable progress goals.

Best Available Retrofit Technology is Reasonable: BART controls are part of the strategy for improving visibility at MANE-VU Class I areas. MANE-VU prepared reports to provide states with information about available control technologies (e.g., MANE-VU's "Assessment of Control Technology Options for BART-Eligible Sources," March 2005), estimated cost ranges and other factors associated with those controls. The reasonable progress goals established in this Regional Haze SIP assume that states whose emissions affect MANE-VU Class I areas will make determinations demonstrating the reasonableness of BART controls for sources in their states.

Table 11-5
Estimated Emissions from BART-Eligible Facilities MANE-VU States

State	Facility Name	Unit Name	SCC Code	Plant ID *	Point ID *	Facility Type	Fuel	2002 SO_2 Emis sions (tons)	2018 SO_2 Emissions (tons)
MD	EASTALCO ALUMINUM	28	30300101	021-0005	28	Metal Production		1506	1356
MD	EASTALCO ALUMINUM	29	30300101	021-0005	29	Metal Production		1506	1356
MD	LEHIGH PORTLAND CEMENT	39	30500606	013-0012	39	Portland Cement		9	8
MD	LEHIGH PORTLAND CEMENT	16	30500915	021-0003	16	Portland Cement		1321	1,189
MD	LEHIGH PORTLAND CEMENT	17	30500915	021-0003	17	Portland Cement		976	878
MD	WESTVACO FINE PAPERS	2	10200212	001-0011	2	Paper and Pulp		8923	1338
ME	Wyman Station	Boiler 3	10100401	2300500135	004	EGU	Oil	616	308
ME	SAPPI Somerset	Power Boiler #1	10200799	2302500027	001	Paper and Pulp	Oil/Wood Bark/Process Gas	2884	1442
ME	IP Jay	Power Boiler #2	10200401	2300700021	002	Paper and Pulp	Oil	3086+	1543
ME	IP Jay	Power Boiler #1	10200401	2300700021	001	Paper and Pulp	Oil	2964+	1482
NY	KODAK PARK DIVISION	U00015	10200203	8261400205	U00015	Chemical Manufacturer		23798	14216
NY	LAFARGE BUILDING MATERIALS INC	41000	30500706	4012400001	041000	Portland Cement		14800	4440

*(from the MANE-VU Inventory)
+1999 emissions

11.4.2 The MANE-VU Low Sulfur Fuel Strategy

The MANE-VU region, especially the northeast, is heavily reliant on distillate oil for home space heating, with more than with more than 4 million gallons used, according to 2006 estimates from the Energy Information Administration[47]. Likewise, the heavier residual oils are widely used by non-EGU sources, and to a lesser extent the EGU sector. The sulfur content of distillate fuels currently averages above 2000 ppm (0.2percent). Although the sulfur content of residual oils varies by source and across the region, it can exceed 2.0 percent. In 2002, combustion of distillate and residual fuel in the MANE-VU region resulted in SO_2 emissions totaling approximately 380,000 tons.

As the second component of MANE-VU's long term strategy, the member states agreed to pursue measures that would require the sale and use of fuel oils having reduced sulfur content. This strategy would be implemented in two phases:

1. Phase 1 would require reducing the sulfur content in distillate (#1 and #2) fuel oils from current levels of 2,000 to 2,3000 ppm (0.20 to .23 percent) to a maximum of 500 ppm (0.05 percent) by weight. It would also restrict the sale of heavier blends of residual (#4 and # 5 and #6) fuel oils that have a sulfur content greater than 2,500 ppm (0.25 percent) and 5, ppm (0.5 percent) by weight, respectively.
2. Phase 2 would require further reducing the sulfur content of the distillate fraction from 500 ppm (0.05 percent) to 15 ppm (0.0015 percent) while keeping the sulfur limits on residual oils at first-phase levels.

The two phases are to be introduced in sequence with slightly different timing for an inner zone of the MANE-VU states[48] and the remainder of the MANE-VU states. While all MANE-VU states have agreed to pursue implementation of both phases to full effect by the end of 2018, it is possible that not every state can make a firm commitment to these measures today. States are expected to review the situation by the time of the first five-year regional haze progress report.

Reductions in sulfur dioxide emissions will occur as a direct consequence of the low-sulfur fuel strategy. For both phases combined, it is estimated that SO_2 emissions in the MANE-VU region will decline from 2002 levels by 168,222 tons per year for combustion of light distillates, and by 42,875 tons per year for combustion of the heavier fuels. Together, these reductions represent a 35 percent decrease in the projected 2018 SO_2 emissions inventory for non-EGU sources in the region.

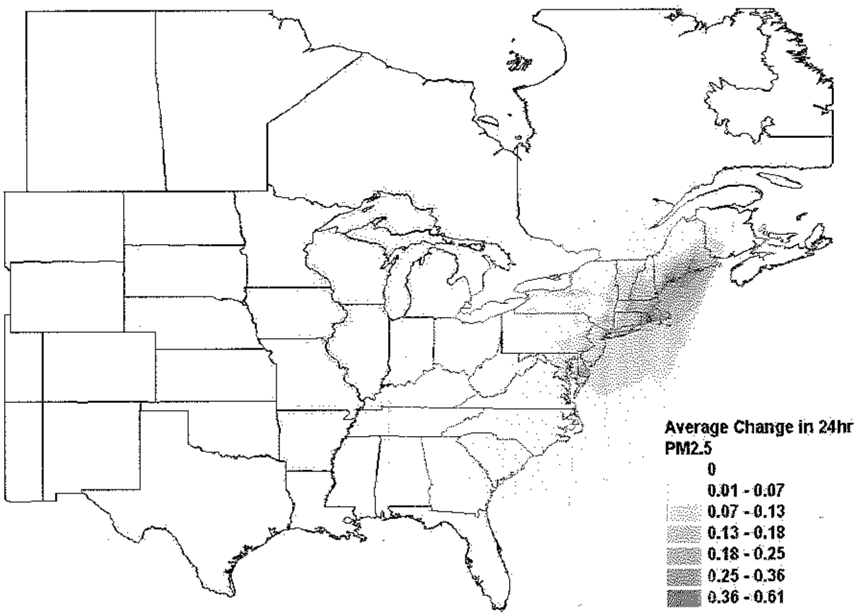
NESCAUM analyzed both steps of the program separately, but it is the combined benefit of implementing the program that is relevant to the question of visibility improvement by 2018. To estimate the total 2018 emissions reductions from this strategy, MANE-VU applied the expected sulfur dioxide emission reductions to all non-EGU sources burning #1, #2, #4, #5, or #6 fuel oil. These emission reductions would result directly from the

[47] U.S. Department of Energy, EIA, Table F3a, at http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html.
[48] The inner zone includes Delaware, Maryland, New Jersey, New York, and possibly portions of eastern Pennsylvania.

lowering of fuel sulfur content from original levels to 0.0015 percent for #1 and #2 oil, to 0.25 percent for #4 oil and to 0.5 percent for #5 and #6 oil.

The reduction in SO_2 emissions by 2018 will yield corresponding reductions in sulfate aerosol, the main culprit in fine particle pollution and regional haze. The full benefits of MANE-VU's low-sulfur fuel strategy is represented in Figure 11-1, which displays the estimated average change in 24-hr average $PM_{2.5}$ for the combined first and second phases of the low-sulfur fuel strategy as calculated by the CMAQ model.

Figure 11-1
Average Change in 24-hr $PM_{2.5}$ Due to Low Sulfur Fuel Strategies Relative to OTB/OTW
($\mu g/m^3$)



Low Sulfur Fuel Oil Requirements are Reasonable: The MANE-VU Contribution Assessment documented source apportionment analyses that linked visibility impairment in MANE-VU Class I areas with SO_2 emissions from sources burning fuel oil. The reasonable assumption underlying the low-sulfur fuel oil strategy is that refiners can, by 2018, produce home heating and fuel oils that contain 50 percent less sulfur for the heavier grades (#4 and #6 residual oil), and a minimum of 75 percent and maximum of 99.25 percent less sulfur in #2 fuel oil (also known as home heating oil, distillate, or diesel fuel) at an acceptably small increase in price to the consumer.

Four-Factor Analysis- Low sulfur Fuel Oil Strategy

The MANE-VU Reasonable Progress Report discussed the four factors as they apply to low sulfur fuel use for industrial, commercial, and institutional boilers and residential heating systems. MANE-VU's Reasonable Progress Report identified switching to lower sulfur oil as an available SO_2 control option that would achieve 50 to 90 percent reductions in SO_2 emissions from ICI Boilers. The report also noted that home heating oil use generates an estimated 100,000 tons of SO_2 emissions in the Northeast each year, and that SO_2 emissions would decline in proportion to reductions in fuel sulfur content. The following discussion summarizes information concerning the four factors for the low-sulfur fuel strategy.

Costs of Compliance

The MANE-VU Reasonable Progress Report noted that because of requirements for motor vehicle fuels, refineries have already performed the capital investments required for the production of low sulfur diesel (LSD) and ultra-low sulfur diesel (ULSD). The report estimated a cost per ton of SO_2 removed by switching to lower sulfur fuel would range from \$554 to \$734 per ton (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383). In some seasons and some locations, low sulfur diesel is actually cheaper than regular diesel fuel. (See Chapter 8 of the Reasonable Progress Report.)

The sulfur content of #4 and #6 fuels can also be cost-effectively reduced. Residual oil is essentially a by-product of the refining process, and is produced in several grades that can be blended to meet a specified fuel sulfur content limit. New York Harbor residual fuel prices for the week ended March 21, 2008 ranged from a low of \$71.38 a barrel for 2.00 and 2.2 percent sulfur fuel; to a high of \$91.38 per barrel for 0.3 percent sulfur fuel. Low pour[49] fuel oil with 0.5 percent sulfur sold for \$80.83 per barrel in this same period[50].

While the costs for achieving the projected emissions reductions with the low-sulfur fuel strategy are somewhat dependent on market conditions, they are believed to be reasonable in comparison to costs of controlling other sectors. Some MANE-VU states are proceeding with low-sulfur oil requirements much sooner than 2018; however, all of the MANE-VU states concur that a low-sulfur oil strategy is both reasonable and achievable by 2018. MANE-VU has concluded that the cost of requiring lower sulfur fuel is reasonable.

Time Necessary for Compliance

MANE-VU's Reasonable Progress Report indicated that furnaces and boilers would not have to be retrofit and would not require expensive control technology to burn ULSD distillate fuel oil. Therefore, the time necessary for compliance would be determined by the availability of the fuel.

[49] Low pour refers to a low-temperature pour point (or reduced viscosity at low temperature) for the fuel.
[50] During this same period, residual oil with a fuel sulfur content limit of 0.7 percent and 1.0 percent traded at \$75.13 and \$72.63, respectively.

The MANE-VU Reasonable Progress Report notes that, on a national scale, more ULSD is produced than both LSD and high sulfur fuel, and concludes that there is sufficient domestic infrastructure to produce adequate stocks of LSD and ULSD. The NESCAUM Low Sulfur Heating Oil Report[51] also observes that the federal rules for heavy-duty highway diesel fuel are flexible, so that if there is a shortage of 15 ppm fuel, the 15 to 500 ppm fuel could be used to relieve the shortage. With this flexibility, the report concludes that the likelihood of a fuel shortage in the short term due to use of ULSD for heating oil is diminished. 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.

Potential supply disruptions and price spikes for residual fuels were a particular concern for several northern MANE-VU states. While the potential for disruptions in the supply of residual fuels is greater than that for distillate oil, these disruptions would affect only a limited number of states during extreme weather events.

MANE-VU has identified several mechanisms that could be implemented to address disruptions, including seasonal averaging and emergency waivers. A seasonal averaging approach would reduce potential supply constraints by allowing the use of higher sulfur fuel during periods of peak demand (and limited supply), and then requiring the increased sulfur content of these fuels to be offset through the use of a lower sulfur fuel at other times. This approach would provide regulatory certainty and greater flexibility during the winter months when fuel supplies may be subject to weather-related disruptions, but at a cost of increased recordkeeping and compliance monitoring. Since many states already have statutory authority to waive fuel sulfur limits for an emergency waiver, states could also utilize their discretionary powers to address short-term supply disruptions.

The strategy adopted by Maine and the other MANE-VU states proposes to phase in the required use of lower-sulfur fuels over the next 8 years, providing adequate time for full implementation.

Energy and Non-Air Quality Environmental Impacts of Compliance

According to MANE-VU's Reasonable Progress Report, reducing the sulfur content of fuel oil would have a variety of beneficial consequences for boilers and furnaces using this fuel. Low-sulfur distillate fuel is cleaner burning and emits less particulate matter, thereby substantially reducing the rate of fouling of heating units and allowing longer time intervals between cleanings. The MANE-VU report cites a study by the New York

[51] "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues", December 31, 2005 by NESCAUM.

State Energy Research and Development Authority (NYSERDA) showing that boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. The use low-sulfur oil could extend the useful life of a source by reducing the maintenance required because low-sulfur oil is less damaging to the combustion equipment. The report also notes that decreasing sulfur levels in fuel would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing equipment that recovers energy normally lost to the heating of water vapor in the exhaust gases.

Furthermore, SO_2 controls would also have beneficial environmental impacts by reducing acid deposition and helping to decrease concentrations of $PM_{2.5}$. Reductions in $PM_{2.5}$ would potentially help nonattainment areas meet health-based National Ambient Air Quality Standards.

Remaining Useful Life of Any Potentially Affected Sources

Residential furnaces and boilers have finite life spans, 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 boiler is 20-25 years. As noted above, use of low-sulfur fuel is less damaging to equipment and could therefore extend the useful life of an oil-fired residential furnace or boiler.

Available information on the remaining useful life of ICI boilers indicates a wide range of life expectancies, depending on unit size, capacity factor[52], and level of maintenance performed. The typical life expectancy of an ICI boiler ranges from 10 years to more than 30 years. As in the case of residential units, use of lower-sulfur fuels could extend the lifespan of an ICI boiler.

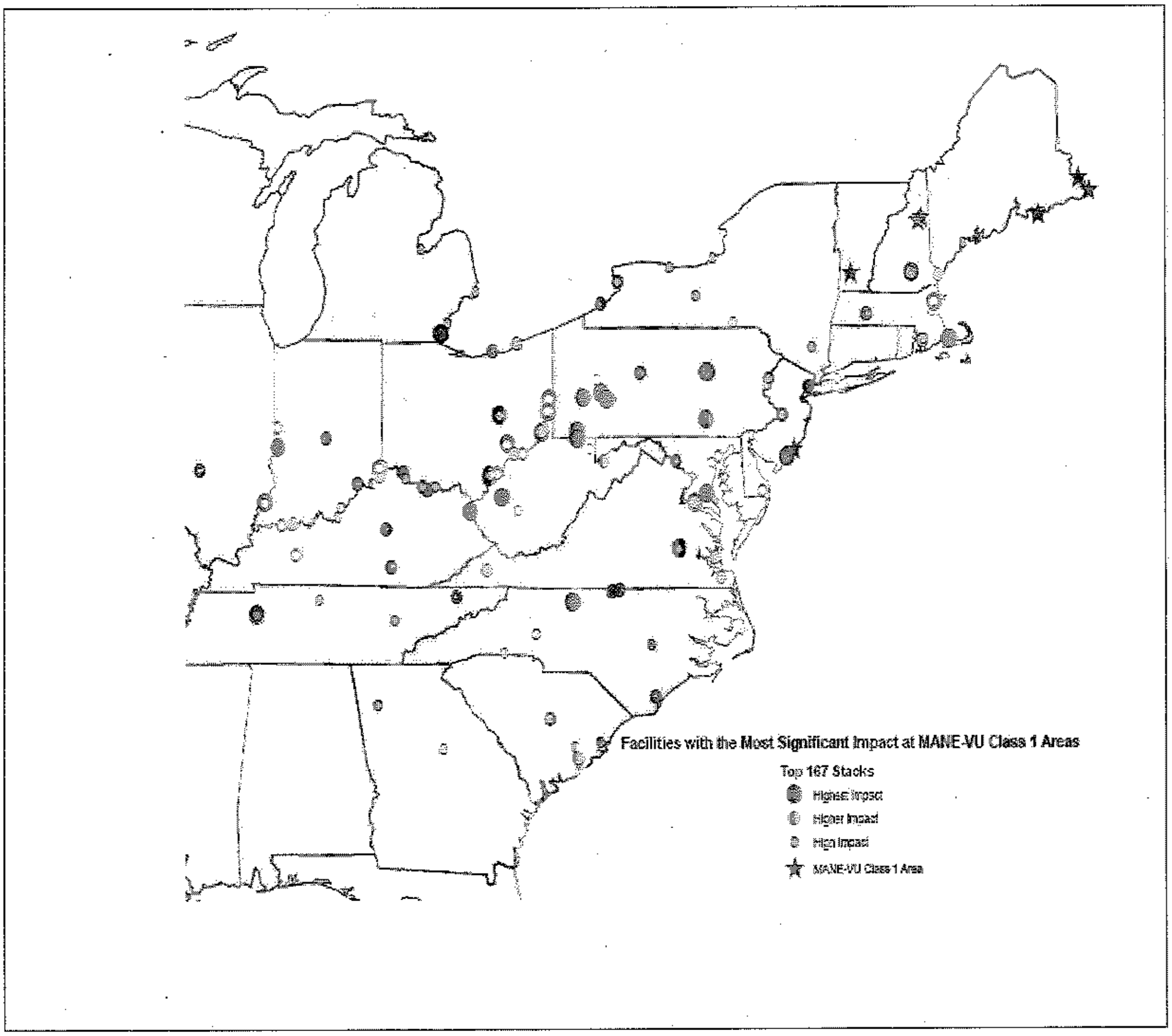
11.4.3 Targeted Strategy for Reducing SO_2Emissions from EGU Stacks

EGUs are the single largest sector contributing to visibility impairment at MANE-VU Class I areas. SO_2 emissions from power plants continue to dominate the emissions inventory. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of the extinction on the days of worst visibility (NESCAUM's Contribution Assessment and Conceptual Model, Attachment A).

To ensure that EGU controls are targeted at those EGUs with the greatest impact on visibility at MANE-VU Class I areas, a modeling analysis was conducted to identify the individual sources responsible for the greatest contributions to visibility impairment. Accordingly, MANE-VU developed a list of the 100 EGUs having the greatest impacts at each MANE-VU Class I area during 2002 The combined list for all seven MANE-VU Class I areas identified a total of 167 distinct emission points, with these stacks located throughout the Northeast, Midwest and Southeast (Figure 11-2)

[52] Capacity factor is defined as the actual amount of energy a boiler generates in one year divided by the total amount it could generate if it ran full time at full capacity.

Figure 11-2
Location of 167 EGU Stacks Contributing the Most to Visibility Impairment at MANE-VU Class I Areas

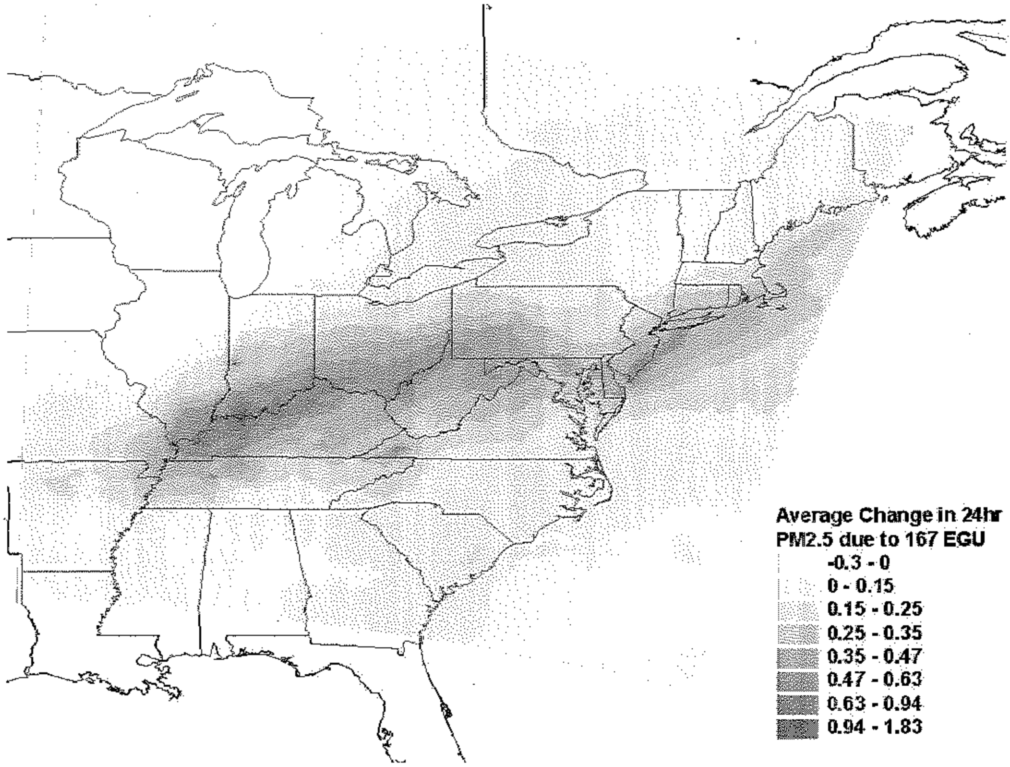


After consultations with its member states and other RPOs MANE-VU requested a 90-percent reduction in SO_2 emissions from the top 167 stacks no later than 2018 (See the MANE-VU "Ask," described in Section 3.4 of this SIP). NESCAUM's preliminary modeling for MANE-VU showed that reducing SO_2 emissions from the targeted facilities by 90 percent would also produce measurable improvements in ambient 24-hour $PM_{2.5}$ concentrations. Assuming a control level equal to 10 percent of the 2002 baseline emissions (i.e., 90 percent emission reduction), NESCAUM used CMAQ to model sulfate concentrations in 2018 after implementation of controls. The modeled sulfate values were then converted to estimates of $PM_{2.5}$ concentrations.

Figure 11-3 illustrates the reduction in fine particle pollution in the Eastern U.S. that would result from implementing the targeted EGU SO_2 strategy. Improvements in $PM_{2.5}$

concentrations would occur throughout the MANE-VU region as well as for portions of the VISTAS and Midwest RPO regions, especially the Ohio River Valley.

Figure 11-3
Preliminary Estimate of Average Change in 24-hr $PM_{2.5}$ Due to 90 Percent Reduction in SO_2 Emissions from 167 EGU Stacks Affecting MANE-VU



Although the reductions are potentially large, MANE-VU determined, after consultation with affected states, that it was unreasonable to expect that the full 90-percent reduction in SO_2 emissions would be achieved by 2018. Therefore, additional modeling was conducted to assess the more realistic scenario in which emissions would be controlled by the individual facilities and/or states to levels already projected to take place by that date. At some facilities, the actual emission reductions are anticipated to be greater or less than the 90 percent benchmark. For a detailed description of this analysis, see Alpine Geophysics' report for MARAMA entitled "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling, Revised Final Draft, April 21, 2008 (Attachment S).

Targeted EGU SO_2 Emissions Reductions are Reasonable: MANE-VU identified specific EGU stacks that were significant contributors to visibility degradation at MANE-VU Class I areas in 2002 based on CALPUFF modeling analyses documented in the Contribution Assessment. MANE-VU obtained information about existing and planned controls on emissions from those stacks. These analyses and the information on proposed EGU controls are presented in the MANE-VU Reasonable Progress Report, and the

Contribution Assessment (specifically Attachment D),as well as in Section 8.0 (Emissions Inventory), and Section 12.0 (Long Term Strategy) of this SIP.

Based on information gathered from the states and RPOs, MANE-VU anticipates that emissions from many of the specific EGU stacks will be controlled as a result of EPA's Clean Air Interstate Rule (CAIR). Since CAIR is a cap and trade program, it is not possible to predict with certainty which of the 167 stacks will in fact be controlled under CAIR in 2018.

Four-Factor Analysis – Targeted EGU SO_2 Reduction Strategy

Costs of Compliance

Technologies to control the precursors of regional haze are commercially available.[53] Because 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 (@100MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, the cost data clearly indicate that many technologies provide substantial and cost-effective reductions.

Both wet and dry flue gas desulfurization ("scrubbers") are in wide commercial use in the U.S. for controlling SO_2 emissions from coal-fired power plants. The capital costs for new or retrofit wet or dry scrubbers are higher than the capital costs for NO_x and PM controls. Capital costs ranged from $180/kW for large units (larger than 600 MW) to as high as $350/kW for small units (200 to 300 MW). (See pages 2-22 of the NESCAUM report "Assessment of Control Technologies for BART Eligible Sources," March 2005, Attachment R). However, the last few years have seen a general trend of declining capital costs due to vendor competition and technology maturation. Also, the cost-effectiveness (in dollars per ton of emissions removed) is very attractive because the high sulfur content of the coal burned by these units results in a very large amount of SO_2 removed by the control devices. The typical cost-effectiveness is in the range of 200 to 500 dollars per ton of SO_2 removed, although the cost rises steeply for small units burning low-sulfur coals and operating at low capacity factors. For any unit, the overall cost effectiveness is determined mostly by the baseline pre-controlled SO_2 emission rate (or fuel sulfur content), size and capacity factor of the unit, as well as the capital cost of flue gas desulfurization (generally ranges from $150 to $200/Kw).

The MANE-VU Reasonable Progress Report reviewed options for controlling coal-fired EGU boilers, including switching to lower-sulfur coal, switching to natural gas, coal cleaning, and flue gas desulfurization (FGD). The most effective control option (but not necessarily appropriate for all installations) is FGD, which can achieve up to a 95 percent reduction in SO_2 emissions. The cost varies considerably among units and was estimated to range from as low as $170/ton to as high as $5,700/ton. Table 11-6 summarizes the estimated SO_2 control costs on a dollar per ton of SO_2 removed basis.

[53]The information in this and the next paragraph comes from the "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, prepared by NESCAUM, in partnership with MANE-VU.

Table 11-6
Estimated Cost Ranges for SO_2 Control Options for Coal-Fired EGU Boilers
(2006 dollars per ton of SO_2 removed)

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.

To predict future emissions and further evaluate the costs of emission controls for electric generating units, MANE-VU and other RPOs have followed the example of EPA in using the Integrated Planning Model (IPM®), an integrated economic and emissions model for EGUs. This model projects electricity supplies based on various assumptions while at the same time developing least-cost solutions to electrical generating needs within the specified emissions targets. IPM also provides estimates of the costs of complying with various policy requirements.

EPA developed IPM version 2.1.9 and used this model to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR)[54]. Recently, EPA updated their input data and developed IPM v3.0. However, because of time constraints, all MANE-VU modeling runs were based on EPA IPM v2.1.9 with changes made to the input assumptions. As

[54] CAMR was also vacated by the federal courts and is no longer in effect.

stated previously, CAIR has recently been remanded to EPA and it is unknown at this time when EPA will propose a revised or new rule in accordance with the court's July 11, 2008 decision.

The RPOs collaborated with each other to update EPA Base Case v.2.1.9 using more current data about EGUs with more realistic fuel prices, creating an IPM run called VISTAS PC_1f. The VISTAS IPM run is the basis for regional air quality modeling for regional haze SIPs in MANE-VU.

MANE-VU, through MARAMA, contracted with the consulting firm ICF International to prepare two new IPM runs[55]. The first modeling run, known as the MARAMA CAIR Base Case run, was based on the VISTAS PC_1f run and underlying EPA IPM v.2.1.9 with some updated information on fuel prices, control constraints, etc. This run also goes by the name MARAMA_5c. The second run, called the MARAMA CAIR Plus run (also known as MARAMA_4c), was similarly based on VISTAS PC_1f run and the underlying EPA IPM v.2.1.9, and included updated information used in the VISTAS run, but assumed lower NO_X emission caps and higher SO_2 retirement ratios.

Based on modeling results, MANE-VU estimates that the marginal cost of SO_2 reductions (the cost of reducing an additional ton of emissions) ranges from $640/ton in 2008 to $1,392 ton in 2018.[56]

Costs will vary for individual plants to reduce emissions by 90 percent, as recommended in the MANE-VU Ask. However, this strategy provides states with the flexibility to pursue controls on specific sources as appropriate and to control emissions from alternative sources, if necessary, to meet the 90 percent target established in the Ask.

Given the significance of SO_2 emissions from specific EGU's to visibility impairment in MANE-VU Class I areas, the MANE-VU Commissioners, after weighing all factors- the availability of technology to reduce emissions, the estimated cost of controls, the costs of alternative measures, the flexibility to achieve alternative reductions if necessary, etc. - concluded that the costs of reducing emissions from the identified key stacks was reasonable. Maine agrees with this conclusion for base-load coal-fired units, but recognizes add-on controls may not be cost-effective for oil-fired peaking units.

Time Necessary for Compliance

MANE-VU's Reasonable Progress Report indicates that, generally, sources are given a 2- to 4-year phase-in period to comply with new rules. Under Phase I of the NO_x SIP call, EPA provided a compliance date of about 3.5 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 compliance period from the SIP submittal date. The MANE-VU states concluded that there is more than sufficient time between 2008 and 2018 for

[55] See the report, *Comparison of CAIR and CAIR+ Proposal using the Integrated Planning Model (IPM®)*, ICF Resources LLC, May 2007, Attachment U.

[56] See Table 6, "Allowance Prices (Marginal Costs) of Emissions Reductions..." p. 9, ICF, May 2007, Attachment U.

affected states to adopt requirements and for affected sources to install necessary controls. Maine agrees with this conclusion

Energy and Non-Air Quality Environmental Impacts of Compliance

The MANE-VU Reasonable Progress Report identified several energy and non-air quality impacts as a result of additional EGU controls. These included potential adverse impacts on fuel supplies if there were large-scale fuel switching, the triggering of NSR requirements, and the generation of wastewater and sludge from flue gas desulfurization systems. Conversely, additional controls for SO_2, NOx, and ammonia would have beneficial environmental impacts by reducing mercury emissions, acid deposition and nitrogen deposition to water bodies and natural landscapes. Reductions would also result in decreases in ambient levels of $PM_{2.5}$ with corresponding health benefits. The MANE-VU states concluded that the energy and non-air quality impacts of additional EGU controls are reasonable. Maine agrees with this conclusion

Remaining Useful Life of Any Potentially Affected Sources

As noted in the MANE-VU Reasonable Progress Report, remaining useful life estimates of EGU boilers indicate a wide range of operating lifetimes, depending on unit size, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of air pollution regulations over the years has necessitated emission control retrofits that have increased the expected life spans of many EGUs. The lifetime of an EGU may be extended through repair, re-powering, or other strategies if the unit is more economical to run than to replace with power from other sources. Extending facility lifetime may be particularly likely for a unit serving an area with limited transmission to bring in other power. The remaining useful life of a unit should not be confused with the economic decision of whether or not to continue operating a unit or to re-power or replace it. The cost of environmental compliance is only one of many factors involved in such a decision.

11.4.4 Non-EGU SO_2 Emissions Reduction Strategy Outside the MANE-VU Region

In addition to the measures described above, (i.e., BART, low sulfur fuel within MANE-VU, and targeted controls on specific EGUs), MANE-VU asked states in neighboring regional planning organizations to consider further non-EGU emissions reductions comparable to those achieved by states located within the MANE-VU region through the application of MANE-VU's low sulfur fuel strategy. Previous modeling indicated that the MANE-VU low sulfur fuel strategy would achieve a greater than 28 percent reduction in non-EGU SO_2 emissions by 2018. After consultation with other states and consideration of comments received, the MANE-VU Class I States decided to include, in the latest modeling for the VISTAS and MRPO regions, implementation of measures capable of achieving SO_2 emission reductions equivalent to MANE-VU's 28 percent reduction in non-EGU SO_2 emissions in 2018.

To model the impact of this strategy on visibility at MANE-VU Class I areas, MANE-VU had to make reasonable assumptions about where the requested emissions reductions would occur in the VISTAS and MRPO states without knowing precisely how those reductions would be realized. As a means to approximate a 28 percent reduction in non-EGU SO_2 emissions, the following reductions were modeled:

- For control measures in VISTAS and MRPO states:
  - Coal-Fired ICI Boilers: SO_2 emissions were reduced by 60 percent
  - Oil-Fired ICI boilers: SO_2 emissions were reduced by 75 percent
  - ICI Boilers lacking fuel specification: SO_2 emissions were reduced by 50 percent

- For additional controls only in the VISTAS states: SO_2 emissions from other area oil-combustion sources were reduced by 75 percent (based on the same SCCs identified in MANE-VU's oil strategies list)

This modeling scenario represents just one example of realistic strategies that states outside of MANE-VU could employ to meet the non-EGU SO_2 emissions reductions requested by MANE-VU.

A number of non-MANE-VU states have not included, or may not include, the requested 28 percent reduction in non-EGU SO_2 emissions in their initial SIPs. The MANE-VU states encourage EPA to hold these states responsible for satisfying the MANE-VU Ask in the course of preparing their first five-year progress reports in order to meet the CAA national goal of remedying any existing visibility impairment in Class I areas.

Non-EGU SO_2 Emission Reductions Measures Outside the MANE-VU Region are Reasonable: After EGUs, ICI boilers and heaters are the next largest class of SO_2 emitters. ICI boilers are thus a logical choice among non-EGU sources for consideration of additional SO_2 control measures.

ICI Boiler Control Options

Air pollution reduction and control technologies for ICI boilers have advanced substantially over the past 25 years. However, according to the 1998 survey of industrial boilers by EPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had installed any kind of air pollution control device. A larger percentage of coal-fired boilers had installed air pollution control devices: specifically, 47 percent had installed some type of control device, mainly to control particulate matter (PM). Post-combustion SO_2 controls were used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petroleum coke (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 since that date.

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 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. 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).

The exceptions to the nearly universal use of post-combustion controls are found in fuel switching, coal cleaning, and fluidized bed boilers, in which limestone is added to the fuel in the combustion chamber. SO_2 control options for ICI boilers are outlined in Table 11-7. Further descriptions of these SO_2 control technology options are available in Chapter 4 of the MANE-VU Reasonable Progress Report (Attachment T).

The SO_2 removal efficiency of these controls varies from 20 to 99+ percent, depending upon the fuel type and control strategy. For coal-fired boilers, options include switching to low-sulfur coal, coal cleaning, wet FGD, dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 20 to 25 percent for switching to low-sulfur fuel(s) to a high of 60 to 95 percent for wet FGD and spray dry FGD. The majority of control strategies, however, are capable of achieving a 60 percent or greater reduction. Thus, assuming that coal-fired ICI boilers adopt varying levels of controls, with most choosing a 50 to 70 percent reduction strategy and fewer choosing either the 20 percent or the 90 percent reduction strategy, the region-wide average is likely to be in the range of a 60 percent reduction in SO_2 emissions. This assumption is validated by the data which documents that wet FGD systems represent 85 percent of the FGD systems in use in the United States and that FGD systems have an average SO_2 removal efficiency of 78 percent. MANE-VU's modeling of a 60 percent reduction in SO_2 emission from coal-fired ICI boilers is therefore reasonable.

For oil-fired boilers, options include switching to a lower sulfur fuel (e.g., oil or natural gas), dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 40 to 60 percent for dry FGD, to a high of 60 to 95 percent for spray dry FGD. For comparison, the MANE-VU low sulfur fuel strategy assumes a 50 to 90 percent reduction in SO_2 emissions from oil-fired ICI boilers. Assuming a typical distribution of control strategies chosen by the sources, MANE-VU's modeling of an average 75 percent reduction in SO_2 emission from oil-fired ICI boilers is reasonable.

For ICI boilers in which a fuel was not specified, a 50 percent reduction in SO_2 emissions was assumed. ICI boilers in this category include those outside the MANE-VU region for which the current inventory did not specify the type of fuel burned. Because a response was not received from the MRPO, this assumption also encompasses some of the uncertainty regarding the implementation of MANE-VU's non-EGU Ask. Given the paucity of data, a lower reduction in SO_2 emissions (50 percent) was assumed in this category than for coal- or oil-fired ICI boilers. Implementation of one or more of the suggested SO_2 control options capable of achieving an average 50 percent SO_2 reduction at these sources is a reasonable assumption.

Table 11-7
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 chemical 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

For emissions from other area oil-combustion sources in the VISTAS region, an SO_2 reduction of 75 percent was assumed. This is equivalent to the MANE-VU low sulfur fuel strategy. The four factor analysis of this strategy was presented in Section 11.3.2.

Four-Factor Analysis – Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU

Based on the survey of available technologies outlined above and the four-factor analysis summarized below, MANE-VU concludes that each of the strategies assumed for modeling purposes to meet the MANE-VU Ask of a 28 percent reduction in non-EGU SO_2 emissions is reasonable. States should have no difficulty in meeting this benchmark in light of the control efficiencies that are attainable at reasonable costs with retrofit technologies that are available for ICI boilers today.

Costs of Compliance

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 span a relatively larger range, and costs for individual boilers will depend on the capacity of the boiler and typical operating conditions. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

MANE-VU's Reasonable Progress Report (Attachment T) provides emission control cost estimates for ICI boilers in the range of $130 per ton to $11,000 per ton, a very wide range due to the variability of sources and control options in this category.[57] All costs presented below for emission controls on ICI boilers are borrowed from this report. Dollar amounts originated from EPA publications cited in the report and have been converted to 2006 dollars using a conversion factor from www.inflationdata.com.

- *Cost of Fuel Switching:*

Although fuel switching can be a very effective means of reducing SO_2 emissions (reductions of 50 to 99.9 percent are possible), burning low-sulfur fuel may not be a technically feasible or economically practical SO_2 control alternative for every ICI coal-fired boiler. Factors impacting applicability include the characteristics of the plant and the particular type of fuel change being considered. Additionally, switching to a lower sulfur coal can affect fuel handling systems, boiler performance, PM control effectiveness, and ash handling systems. Oil-fired boilers switching to a lower sulfur fuel of the same grade (e.g., switching from #6 fuel oil at 2.0%S to #6 fuel oil at 0.5% S) do not typically encounter these issues; please see Section 11.4.2 for a discussion of the costs and issues associated with switching to low sulfur fuel oil.

The costs of coal fuel switching, including substitution or blending with a low-sulfur coal, can be attributed to two main reasons: the cost of low-sulfur coal compared to higher sulfur coal (including coal's heating value), and the cost of any necessary boiler or coal handling equipment modifications. 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 require potentially significant investments and modifications to an existing plant. Even if a lower sulfur fuel is available, it may not be cost competitive if it must be transported long distances from the supplier or supplied in small quantities. It also may be more cost-effective to burn a higher sulfur fuel supplied by nearby suppliers and to use a post-combustion control device.

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 the wide variation in natural gas process means that it may be uneconomical to consider this option for large ICIs due to the fuel quantity necessary and the price of natural gas. Natural gas is currently about twice times the price of coal in terms of heating value, but has been as high as seven times the price of coal in recent years.

[57]MANE-VU's Reasonable Progress Report is entitled "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas" prepared by MACTEC for MARAMA, dated July 9, 2007.

- 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. The effectiveness of coal cleaning is typically a 20 to 25 percent reduction in SO_2 emissions. Coal cleaning also increases the heating value of the fuel by a small amount.

- Cost of Combustion Controls

Dry sorbent injection (DSI) systems have lower capital and operation costs than post-combustion FGD systems because of the simplicity of the DSI design, lower water use requirements, and smaller land area requirements. Table 11-8 presents the estimated costs of adding DSI-based SO_2 controls to ICI boilers based for different boiler sizes, fuel types, and capacity factors.

- Cost of FGD

Installation of post-combustion SO_2 controls in the form of FGD has several impacts on facility operations, maintenance, and waste handling procedures. FGD systems generally require substantial land area for construction of the absorber towers, sorbent tanks, and waste handling equipment. The facility costs therefore depend on the cost and 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. These costs may be mitigated, however, by utilization of a forced oxidation FGD process that produces commercial-grade gypsum, which may be sold as a raw material for other commercial processes.

Table11-9 presents the total estimated cost effectiveness of adding FGD-based SO_2 controls for different boiler sizes, fuel types, and capacity factors. There is no indication that these cost data include revenue from gypsum sales, which would partially offset the costs of FGD controls.

Carbon dioxide is also emitted as a by-product of FGD, therefore impacts of increased carbon emissions would need to be considered. CO_2 emissions will become more of an issue in the future if they are limited under climate change mitigation strategies. Given the uncertainty of such future strategies, costs related to increased carbon emissions from FGD cannot yet be assessed.

Table 11-8
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	3,793	2,979
		50	1,312	1,062	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

MANE-VU's request for a 28 percent reduction in non-EGU SO_2 emissions allows states flexibility in determining which sources to control, so that the most cost-effective control measures can be adopted and implemented over the next 10 years. Given the wide range of control options and costs available for this purpose, MANE-VU has concluded that its request for a 28 percent reduction in non-EGU SO_2 emissions is reasonable. Maine concurs with this conclusion.

Time Necessary for Compliance

For pre- and post-combustion SO_2 emission controls, engineering and construction lead times will vary between 2 and 5 years, depending on the size of the facility and specific control technology selected. Generally, sources are given a 2-4 year phase-in period to comply with new rules, as previously described, and states generally have a 2-year period for compliance with RACT rules.

For the purposes of this review, it is assumed that a 2-year period after SIP submittal is adequate for the installation of pre-combustion controls (fuel switching or cleaning) and a 3-year period for the installation of post-combustion controls. MANE-VU has therefore concluded that there is sufficient time between 2008 and 2018 for the affected states to adopt emission control requirements and for affected sources to install controls necessary to meet MANE-VU's requested SO_2 emission reductions from non-EGU sources. Maine concurs with this conclusion.

Table 11-9
Estimated 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	FGD (Dry)	40	14	3,781	2,637	1,817
			50	1,379	1,059	828
			83	1,006	814	676
Lower-sulfur coal	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)	85	14	4,183	2,786	1,601
			50	1,290	899	567
			83	843	607	407
High-sulfur coal	FGD (Spray dry)	85	14	3,642	2,890	1,909
			50	1,116	875	601
			83	709	563	398
Lower-sulfur coal	FGD (Wet)	40	14	4,797	3,693	2,426
			50	1,415	1,106	751
			83	892	705	492
Oil	FGD (Wet)	40	14	10,843	8,325	5,424
			50	2,269	1,765	1,184
			83	1,371	1,079	740

Energy and Non-Air Quality Environmental Impacts of Compliance

The primary energy impact of pre- or post-combustion control alternatives is a potential increase in electricity usage. Fuel switching and cleaning do not significantly affect the efficiency of the boiler itself, but require additional energy to clean or blend coal. FGD systems typically operate with high-pressure drops across the control equipment, and therefore consume significant amounts of electricity 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 non-air environmental impacts of fuel switching derive from transportation of the fuel. Secondary environmental impacts derive from waste disposal and material handling operations (e.g. fugitive dust). For FGD systems, the generation of wastewater and sludge from the SO_2 removal process is a consideration. Wastewater from the FGD systems will increase sulfate, metals, and solids loading at the receiving wastewater treatment facility, resulting in potential impacts to operating cost, energy requirements, and effluent water quality. Processing of the wastewater sludge can require energy for stabilization and/or dewatering, and transporting the sludge to the landfill has additional environmental impacts.

Fuel switching to a low-sulfur 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)[58], lowering the fuel sulfur content from 1,400 ppm to 500 ppm will reduce boiler deposits by a factor of two. These reductions in buildup of deposits result in longer service intervals between cleanings.

Reducing SO_2 emissions from ICI boilers would have positive environmental and health impacts. SO_2 controls would reduce acid deposition, helping to preserve aquatic life, forests, crops, and buildings and sculptures made of acid-sensitive materials. These emission reductions would also help to decrease ambient concentrations of $PM_{2.5}$, a significant contributor to premature morbidity and illness in individuals with heart or lung conditions.

MANE-VU has concluded that the energy and non-air environmental impacts of controlling SO_2 emissions from ICI boilers are justified in light of the beneficial impacts on regional haze, fine particulate air pollution, acid rain, and equipment operation, as described above. Maine concurs with this conclusion.

Remaining Useful Life of Any Potentially Affected Sources

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 spans range from about 10 years up to over 30 years. However, the remaining useful life of a source is highly variable; and older units are not likely to be retrofitted with expensive emission controls. Given the typical range of life expectancies of ICI boilers, the technical options available, and the flexibility that non-MANE-VU states would have to meet the Ask, MANE has concluded that its request for a 28 percent reduction in non-EGU SO_2 emissions is reasonable. Maine concurs with this conclusion.

11.5 Visibility Impacts of Additional Reasonable Controls

MANE-VU's evaluations included modeling to estimate the visibility effects of various elements of the Maine/MANE-VU Ask. This modeling is described in NESCAUM's report entitled "MANE-VU Modeling for Reasonable Progress Goals," February 2008, (Attachment P). NESCAUM also conducted more recent, revised modeling to assess the effects of all haze reduction strategies combined. The latter modeling is described in NESCAUM's report entitled "2018 Visibility Projections," March 2008, (Attachment Q). The following information about the effects of specific strategies is taken from these reports.

The NESCAUM modeling demonstrates that significant visibility benefits will accrue from implementation of the additional reasonable control measures described in Subsection 11.4, above. Figures 11.3 and 11.4 describe the results of this modeling. In

[58] Reference 10 in Attachment T.

the first of the two figures, the light yellow bars represent expected visibility at MANE-VU Class I areas in 2018. Comparison of these values with the 2018 "glide slope" values (the plum-colored second bars from the left) shows that all areas are expected to experience visibility improvements that meet or exceed the uniform rate of progress calculated for each area. The second figure shows that, for the 20 percent of days having the best visibility, expected visibility in 2018 will be better than it is today at all locations.

In conclusion, the reasonable progress goals for Class I areas proposed by the MANE-VU states are found to be consistent with the stated national goals of preventing further visibility degradation while making timely progress toward achieving natural visibility conditions in Class I areas by 2064.

Figure 11-3
Demonstration of Required and Reasonable Visibility Progress for 20% Worst Visibility Days

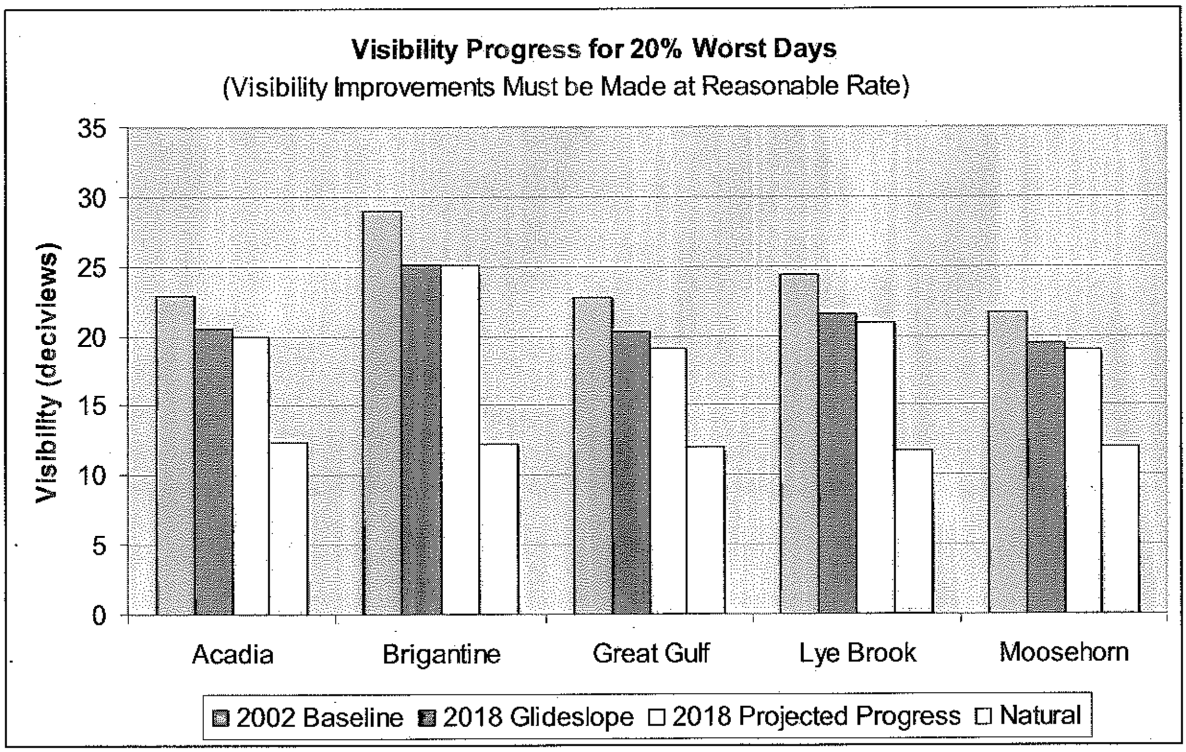


Figure 11-4

Demonstration of Required and Visibility Maintenance for 20% Best Visibility Days