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an absolute limitation of ±0.05 lb/mmBTU on monitoring system inaccuracy. Because the available data does not clearly indicate the need for this cutoff point, EPA specifically requests comment on both the appropriateness of this cutoff rate and the level at which the exception is proposed.

b. Bias

Under the proposed rule, NO_x continuous emission monitoring systems would have to satisfy a bias test, in addition to achieving an acceptable relative accuracy in the performance specification test, for certification. EPA is proposing a t-test, analogous to the tests described for SO_2 pollutant concentration and flow monitors, for the NO_x continuous emission monitoring system. NO_x monitoring systems would be required to pass a t-test, applied to low bias only,[55] at the 95-percent level of confidence. The recorded NO_x emission rate data from a monitoring system that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in Appendix A of the rule. Monitoring systems failing the test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed certification bias test and the time of the next successful bias test.

Based on preliminary statistical analyses of NO_x RATA data for units subject to Subpart Da, EPA believes that the proposed standard can be achieved by well-maintained NO_x monitoring systems using current technology.

c. Calibration Error

As a result of the NO_x emissions averaging provisions under the Acid Rain program, EPA believes that units will operate over a substantially wider range of NO_x emissions rates than those experienced under Subpart Da. NO_x emissions must be measured accurately throughout the entire range of expected emission rates in order to develop viable annual NO_x emission rate averages, particularly for units averaging their emissions with others. Accordingly, EPA is proposing to require three-point calibration error tests, identical to those described previously for SO_2 pollutant concentration monitors, for certification of NO_x pollutant concentration monitors and diluent gas monitors. In contrast to the relative accuracy and bias specifications which apply to the NO_x continuous emission monitoring system as a whole, calibration error standards apply to the pollutant concentration monitor and the diluent gas monitor separately.

EPA also proposes to use Subpart Da's performance

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[55]Considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with an alpha value of 0.025. Thus, in Table 8-1 in Appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

specification of 2.5 percent of calibration error for certification of NO_x pollutant concentration monitors and diluent gas monitors under the Acid Rain program. That is, to qualify for certification, the monitor's measurements of the pollutant (NO_x) or gaseous constituent (O_2 or CO_2) shall not deviate from the known values by more than 2.5 percent for each of three concentration (low, mid-range, and high) levels.

d. Cycle Time/Response Time

EPA proposes to adopt the cycle time/response time test required under Subpart Da for certifying NO_x continuous emission monitoring systems under the Acid Rain program. A description of this test may be found in the section on performance specifications for certification of SO_2 pollutant concentration monitors. Subpart Da's performance specification of 15 minutes as the maximum time allowed for each stepchange would also apply.

3. Quality Assurance and Quality Control Procedures

The quality assurance (QA) and quality control (QC) procedures EPA is proposing for NO_x continuous emission monitoring systems under the Acid Rain program are essentially equivalent to those detailed previously for SO_2 pollutant concentration monitors, except that they would generally apply to the combined monitoring (pollutant concentration monitor and diluent gas monitor) system. These QA/QC procedures consist of a series of tests to be performed periodically to ensure that the continuous emission monitoring systems, once certified, continue to operate reliably and accurately. Also included are specifications for maintaining records of QA/QC test dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA and other applicable regulatory authorities. These latter requirements are discussed later in the section on recordkeeping and reporting.

a. Daily Calibration Error Test

Analogous to the daily calibration tests for SO_2 pollutant concentration monitors, EPA is proposing to expand Subpart Da's daily calibration drift checks for NO_x pollutant concentration and diluent gas monitors into daily calibration error tests so as to quality assure the recorded emissions data on a daily basis. Under the Acid Rain program, affected units would be required to use standard reference material or Protocol 1 gases for these daily calibration error tests in addition to the quarterly calibration error tests.

As discussed previously, accurate NO_x emissions measurements are essential to successful implementation of NO_x annual averages, the NO_x emissions averaging pools, and other flexible components in the Acid Rain program. Accordingly, EPA is proposing to apply the same calibration error standard to the NO_x pollutant concentration monitor and the diluent gas monitor as is being proposed for the SO_2 pollutant concentration monitor. That is, EPA proposes that drift should not exceed 5 percent in a given day. The recorded emissions data from a monitor that fails this calibration error standard would be considered invalid, or "missing," prospectively until monitor error is brought within specification.

b. Periodic Performance Tests

For the same reasons outlined earlier in this preamble in the section describing periodic performance tests for SO_2 concentration monitors, EPA proposes to require two semi-annual performance tests, a relative accuracy test audit (RATA) and a bias test, on NO_x monitoring systems. Quarterly three-point calibration error tests on the NO_x concentration and diluent gas monitors would also be required. The recorded NO_x emissions rate data from a monitoring system that fails a RATA, or the concentration data from a monitor that fails a calibration error test, would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor or monitoring system achieves the required standard. Data that fails a bias test would be adjusted to compensate for bias or, at the source's option, the test could be repeated after corrective action is taken to demonstrate that the correction is no longer necessary. Here, as in the case of SO_2 concentration monitors, the achievement of superior relative accuracy in a given RATA would decrease the required frequency of future testing from semi-annual to annual.

i. Relative Accuracy Test Audit

EPA proposes to require semi-annual relative accuracy test audits of NO_x monitoring systems. These tests would be identical to the tests described previously for certification, and the same performance standard (relative accuracy of 10 percent) would apply. As in the case of SO_2 monitors, NO_x monitoring systems achieving a relative accuracy of 7.5 percent or better would be allowed to decrease the RATA frequency from semi-annual to annual as long as relative accuracy remains at 7.5 percent or better[56]. Table 5 summarizes the required RATA frequency as a function of achieved relative accuracy.

Table 5
RATA Frequency for NO_x Monitoring Systems

Relative Accuracy	Required RATA Frequency
≤10%	Semi-Annual
≤7.5%	Annual

ii. Bias Test

The periodic bias tests on NO_x monitoring systems for the Acid

[56]Sources meeting the 10% requirement but not achieving a relative accuracy of 7.5% or better would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve 7.5%, and thereby lower their RATA frequency.

Rain program would be conducted with the same frequency and at the same time as the RATAs, would employ the RATA data, and would be identical to the bias test described previously for monitoring system certification. The proposed performance standard for NO_x monitoring systems in the bias test is also identical to that proposed for monitoring system certification. That is, under the proposed rule, NO_x monitoring systems would be required to pass a t-test, for low bias only, at the 95-percent level of confidence. As discussed previously, the recorded NO_x emission rate data from a monitoring system that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in Appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitoring system readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitoring system readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitoring system readings.

As proposed, the bias test could be re-taken at any time at the source's option. As discussed earlier in Section C on SO_2 monitors, some have voiced concern that sources might re-run the test many times, "shopping" for a lower adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

iii. Three-Point Calibration Error Test

EPA proposes to require a quarterly three-point calibration error test on NO_x concentration monitors and diluent gas monitors. This test would be identical to the three-point calibration error test described previously for monitor certification, except that the performance standard would be the same as that used for the daily calibration error test. That is, under the proposed rule, a monitor's measurements of NO_x or diluent concentration shall not deviate from the calibration gas value by more than 5 percent for each of three concentration levels (low, mid-range, and high).

F. Missing Data Procedures

Section 412(d) of the Act provides for specific methods for calculating emissions during periods when data from a CEMS or an approved alternative monitoring system are unavailable. The Agency is required to deem the unit to be operating in an uncontrolled manner during the entire period for which the data are not available unless the owner(s) and operator(s) can provide information satisfactory to the Administrator on emissions during that period. Further, EPA must prescribe a standard method to calculate emissions for missing data periods in the Acid Rain CEMS

regulation.

In deliberations regarding the most appropriate procedures for filling in missing emissions data, the Agency has identified several goals that the procedures should satisfy. They are: (1) to provide strong incentives for effective CEMS operation and maintenance programs, thus yielding high CEMS availability and data capture rates; (2) to use less-conservative methods for estimating probable actual emissions for missing data when annual monitor availability exceeds specified thresholds and missing data periods are relatively short; (3) to use more conservative methods for filling in missing data when annual monitor availability falls below specified thresholds and/or missing data periods are longer; (4) to develop procedures for filling in missing data that provide incentives to use CEMS as the primary method for determining emissions; (5) to develop procedures that are automatic in their execution, relying only on the CEMS-generated emissions database, thereby minimizing the need for enforcement actions and supporting the smooth and unambiguous operation of the program; and (6) to develop procedures that are readily implementable by all affected units. The ARAC Emissions Monitoring Subcommittee has, in general, endorsed these goals, although a few members did not concur with the concept of requiring an annual monitor availability threshold.[57] EPA requests comment on whether the proposed procedures satisfy the aforementioned criteria and goals for this program.

The Agency prepared two issue papers on potential procedures for filling in missing emissions data.[58] Simultaneously, UARG has been conducting an extensive series of Monte Carlo simulations and a case study using actual hourly SO_2 concentration data from a Subpart Da unit to develop statistical methods that could be used to fill in missing data without significant loss of accuracy in the annual accounting of SO_2 emissions.[59] Both the EPA and UARG

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[57]E14 - ARAC Emissions Monitoring Subcommittee Minutes, February 20-21, 1991.

[58](1) Missing Data Periods, EPA Issue Paper for ARAC Discussion, January 18, 1991 (IIA-45); and (2) Alternative Proposals for Missing Data Periods, EPA Issue Paper for ARAC Discussion, May 1991 (E-27).

[59]These studies include: (1) Assessing Data Availability at Units Subject to Subpart Da New Source Performance Standards, prepared by Roberson Pitts, Inc., for UARG, September 1990; (2) Evaluation of Missing Data Estimation Methods, prepared by W. S. Pitts Consulting, Inc., for UARG, February 1991; (3) Evaluation of Missing Data Methods - Supplement: Application of Estimation Methods to Actual Hourly SO_2 Emissions Data, prepared by W. S. Pitts Consulting, Inc., for UARG, March 1991; and (4) Technical Note from W. S. Pitts on behalf of UARG to U.S. EPA on Effects of Skewing Missing Data Patterns, April 10, 1991.

studies cited above address only missing SO_2 data. UARG has also submitted a study presenting a method of correlating flow data with unit load data for purposes of missing flow data substitution.[60] EPA has not identified any comparable analyses for missing NO_x emission data.

The UARG studies on SO_2 missing data suggest that statistical estimation methods can be used to fill in missing SO_2 concentration data for periods of short duration above a specified monitor availability threshold without jeopardizing the accuracy of year-end totals for SO_2 emissions. The ARAC Emissions Monitoring Subcommittee found that statistical methods look promising for filling in short-duration data gaps as long as high annual monitor availability is maintained. The Subcommittee did not reach consensus, however, on the exact value(s) of appropriate monitor availability threshold(s), although the range was narrowed to between 90 and 95 percent. Most members endorsed the concept of using graduated monitor availability thresholds. The Subcommittee also did not agree on the appropriateness of using statistical methods for filling in missing data periods longer than three hours.[61]

In various discussions on this matter, other industry representatives have indicated that the prompt corrective action that EPA wants to encourage when the CEMS system malfunctions sometimes requires more than 3 hours to complete. As a result, they have suggested that a first tier "cutoff" value of 6 hours appears to be more appropriate. Others have suggested that such corrective action could usually be completed within an 8-hour work shift, and have suggested 8 hours as the appropriate value for the first tier cutoff. In today's proposal, 6 hours was selected as the most appropriate first-tier cutoff value, based on EPA's judgment that most corrective action can be completed within that time. EPA requests comment on the appropriateness of this or other choices for the cutoff value defining Tier I.

EPA has also received suggestions on the most appropriate substitute value to select from a given lookback period. As discussed earlier, the value chosen as a substitute must be designed to be conservative (i.e., it must be more likely to be an overestimate than an underestimate), and it should be increasingly conservative as the lookback period gets longer. EPA considered using the highest value over a given lookback period as the substitute value. However, others have suggested that selecting the highest value in a given lookback period may catch an anomalous outlier value not reflecting actual conditions, and have thus

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[60]"Alternative Procedure for Estimating Volumetric Flow Rate," Technical Memorandum to UARG from Science Applications, Inc., 6/19/91.

[61]Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes - February 20-21, 1991 and April 29-30, 1991.

suggested the use of another value such as the second-highest, the third-highest, the average of the top five, or the 90th percentile.

EPA considered all these possibilities, finding each of them to exhibit at least one of the aforementioned problems in some degree. The second- or third-highest value or an average of several high values could still suffer from the outlier problem. The 90th-percentile value avoids this problem entirely. However, any percentile-based approach has the drawback of not always preserving the desired property of being more conservative as the lookback period gets longer, and may be less than the actual emission value approximately ten percent of the time. In cases where this occurs, the percentile-based approach would not provide operators the intended incentive to restore the monitor to operation as quickly as possible. Nevertheless, by using the 90th percentile as opposed to average data, the missing data procedure will normally be conservative relative to the expected value.

After weighing the aforementioned factors, EPA narrowed the list of candidates for missing data substitution to: a modified 90th-percentile approach, which was chosen for today's proposal and is described below, and an approach which selects the average of the five highest values as the missing data substitute. The modified 90th-percentile approach was selected because it completely avoids the outlier problem described earlier.

Today's proposal uses the 90th-percentile value as a replacement for missing data. EPA believes that the current pattern of monitor operating practice will continue, thus preserving the conservative property of the percentile approach. However, to protect against the possibility of unintended and possibly perverse incentives, EPA is proposing to require that emission values over the lookback period be correlated with the sulfur content of the fuel being burned, and that the 90th-percentile value be chosen from the set of values recorded at times when the sulfur content of the fuel burned matches that of the missing data period. Moreover, to protect further against the possibility of providing lower-than-actual missing data values, EPA has combined the percentile approach with the probable-actual approach, wherein estimates are generated by taking the average of the hours before and after the missing data period. By taking the higher of these two emission estimates, EPA believes that the potential to under-report emissions will be minimized. As a result, EPA requests comment on whether it is necessary to correlate sulfur concentration in the emissions with the sulfur content of the coal under the percentile approach so long as this proposed underreporting protection is retained. EPA has also considered suggestions that missing data might be filled in using a case-by-case regression analysis of emissions with fuel sulfur content for each fuel supply at each unit, and requests comment on this possibility as well.

In developing its proposal, EPA considered the average-of-the-top-five-values approach to be the most attractive alternative to the proposed percentile approach, since it avoids the potential for underreporting emissions while significantly reducing the possible

impact of outlier values. Moreover, like the other non-percentile approaches, it eliminates the need to correlate fuel sulfur content with emission rate, thus simplifying the data system software requirements. EPA specifically requests comment on the relative merits of the average-of-the-top-five approach and the 90th-percentile approach proposed today. EPA also requests comment on the merits of other candidate missing data routines which would substitute the highest, second-highest, or third-highest values recorded during the specified lookback period.

1. Rejected Alternatives

Representatives of State agencies and environmental groups have urged EPA to promulgate regulations under the Acid Rain program that will encourage the use of backup CEMS hardware rather than statistical or other estimation methods for filling in missing emissions data, at least for high-emitting units. EPA has considered the option of requiring all units to install a duplicate certified CEMS to supply missing emissions data when the primary CEMS is not available. EPA has concluded that this would be a costly alternative if applied universally, and may not necessarily produce significantly more accurate emissions data if high annual monitor availabilities (on the order of 95 percent) are maintained.

In ARAC discussions, some have also requested EPA to consider proposing different procedures for filling in missing emissions data, depending on the reason for CEMS unavailability.[62] They have recommended limiting the use of less conservative statistical estimation methods to filling in missing data periods resulting from QA/QC activities and using more conservative methods for periods resulting from poor monitor maintenance. While EPA endorses the general principle of providing incentives for aggressive, effective CEMS QA/QC and preventative maintenance programs, a tally of the possible reasons for missing data has indicated that this approach would be exceedingly cumbersome to implement and enforce.

2. Proposed Approach

The proposed rule would use a modified form of the statistical estimation methods developed by UARG for filling in missing SO_2 concentration data in cases where availability is above specified thresholds and missing data periods are relatively short. Where availability falls below these thresholds, and missing data periods are longer, the proposed rule would require more conservative procedures within a given fuel sulfur content range. The procedures for NO_x and flow missing data would be similar to the SO_2 procedures, but would incorporate correlations between load and emissions or flow data rather than the sulfur-in-fuel correlation used for SO_2.

The missing data procedures being proposed today would also provide a tiered system to promote high CEMS emissions data capture rates mandated by the Act and necessary for the proper functioning

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[62]E26 - Arizona Department of Environmental Quality, Comments on EPA Issue Papers, N. Wrona, February 15, 1991.

of the SO_2 allowance trading market and the NO_x emissions averaging provisions of the Acid Rain program.

The proposed rule would require affected units to calculate, on a daily basis, annual monitor availability (defined as a rolling percentage of total unit operating hours during the previous 365 days) for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system, and to substitute conservative estimates for missing data as a function of availability, length of missing data period, sulfur content range for SO_2, and load range for NO_x and flow. The monitor availability thresholds have been placed at levels that, according to the EPA and UARG studies cited previously, can be achieved by well-maintained monitors based on current technology. These studies indicate that the average annual availability during 1988-1990 of both SO_2 and NO_x monitors, at units subject to Subpart Da requirements was above 95 percent, and that over 90 percent of these monitors achieved an annual availabilities above 90 percent.

a. <u>SO_2 Concentration Missing Data Procedures</u>

Under today's proposal, each affected unit would establish fuel sulfur content ranges based on a single fuel analysis every six hours which is correlated to the hourly CEMS values. EPA believes that this sampling frequency will yield a sufficiently accurate correlation between the CEMS emission rates and the actual sulfur content of the coal. These ranges would be established and used to ensure that neither significant overreporting or underreporting of emissions will occur due to the missing data routine. The 90th-percentile value would be calculated on a rolling daily basis for each of the previous 30 or 365 days for use in the missing data routine as described below. Whenever a missing data period occurred which required such a value, the operator would identify the sulfur-content range for the coal fired during that hour and select the 90th-percentile value from the appropriate range.

If annual SO_2 concentration monitor availability is greater than or equal to 95 percent, an estimate of probable actual emissions or flow consisting of the arithmetic average of the values for the hour immediately before and the hour immediately following the missing data period would be used to fill in missing data periods up to and including 24 hours.

If the missing data period exceeds 24 hours, but annual monitor availability is greater than or equal to 95 percent, the owner(s) and operator(s) would substitute for each hour in the missing data period the higher of the 90th-percentile hourly SO_2 concentration recorded by the monitor during the previous 30 days in the relevant sulfur-content range for the unit during the missing data period, or the average of the hour before and the hour

after the missing data period, whichever is higher.[63]

Two reasons have prompted EPA to select 24 hours as the cutoff for using less conservative statistical estimation methods: (1) Various analyses, including UARG's, provide support for only very limited use of statistical methods, if at all, for filling in missing data periods over 24 hours; and (2) 24 hours, according to some utility representatives, corresponds to the time needed to transport, warm-up, and calibrate a portable CEMS as a replacement for a malfunctioning primary CEMS.

If annual monitor availability is less than 95 percent, but greater than or equal to 90 percent, the proposed rule provides a three-tiered system for filling in missing data where each tier is related to the length of the missing data period. As mentioned previously, the proposed methods for filling in missing data are intended to become more conservative as the length of the missing data period increases.

Tier 1 would apply to missing data periods up to and including 6 hours, which represents over 75 percent of all missing data according to the UARG study. In this tier, EPA proposes to use an arithmetic average of the emissions values recorded for the hour immediately before and the hour immediately following the missing data period to fill in each hour of the missing data period.

Tier 2 would apply to missing data periods greater than 6 hours but less than or equal to 24 hours. In this tier, EPA proposes to use either the 90th-percentile hourly SO_2 concentration for the appropriate coal sulfur-content range recorded during the previous 30 days, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. Substitute data obtained by this procedure may be somewhat more conservative than the substitute data used in Tier 1, thereby providing an incentive for prompt repair of monitors when they malfunction.

Tier 3 would apply to missing data periods greater than 24 hours. In this tier, EPA proposes to use either the 90th-percentile hourly SO_2 concentration recorded by the monitor during the previous 365 days, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. EPA has selected this conservative procedure for filling in long missing data periods to discourage the incidence of such periods and to promote the use of a back-up, portable, certified CEMS as a replacement for a malfunctioning primary CEMS.

The Agency believes that this three-tiered approach strikes a balance between the goal of providing incentives for high monitor availability and the concern that overly conservative methods for filling in missing data might lead to capital expenditures for

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[63]Previous substitute data determined by a missing data routine would not be included for the purposes of determining the 90th-percentile hourly SO_2 concentration during any previous period.

duplicate monitors by all (or most) affected units. Such expenditures may not be warranted in terms of expected incremental improvements in the accuracy of SO_2 emissions data, particularly for low-emitting and moderate-emitting units.

If annual monitor availability falls below 90 percent, the proposed rule would require the use of either the 90th-percentile hourly SO_2 concentration for the appropriate sulfur-content range recorded by the monitor during the previous 365 days of service, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. The Act requires EPA to declare a unit to be operating in an uncontrolled manner if substitute data satisfactory to the Administrator cannot be provided during missing data periods. EPA believes no satisfactory substitute data exists when annual monitor availability is less than 90 percent and, thus, is defining the 90th-percentile hourly value recorded over the preceding 365 days in the corresponding sulfur-content range as equivalent to uncontrolled emissions.

For affected units not equipped with add-on emission controls, the prescribed missing data procedures would be considered as "satisfactory to the Administrator" without any additional information. Under the proposed rule, affected units with add-on emission controls such as flue gas desulfurization (FGD) for SO_2 or selective catalytic reduction (SCR) for NO_x would monitor specified parameters to document the proper operation of their control equipment during missing data periods. The proposed rule specifies the required parameters for monitoring the pollution removal efficiency of different types of add-on emission controls. For example, affected units equipped with wet FGD control systems ("scrubbers") would be required to record and report the following information for each hour during all missing data periods: number of scrubber modules in operation, percent solids in slurry, feedrate of makeup slurry, inline measure of absorber pH, and average pressure differential across each scrubber module. A national utility association representing many scrubbed units has indicated that it is reasonable to require the continuous monitoring of these emission control parameters during all missing data periods.[64]

Because affected units with add-on emission controls are likely to experience greater swings in emissions variability, EPA is proposing to allow these units to develop optional alternate procedures for filling in missing data based on parameter monitoring correlations. Under the proposed rule, such alternate procedures would be approved only on a site-specific basis and they could be used only to fill in missing data periods when annual monitor availability is greater than or equal to 90 percent. Prior to the approval of a site-specific parameter monitoring procedure for filling in missing data, affected units with add-on emission

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[64]"Missing Data Periods for Affected Coal-Fired Utility Units," Large Public Power Council, April 25, 1991.

controls would be required to use the statistical estimation and other procedures prescribed in the proposed rule. EPA requests comment on these procedures, as well as comment on the question of whether there is a less complex way to achieve comparable results.

b. Flow and NO_x Emissions Missing Data Procedures

For flow and NO_x emissions, the proposed rule retains the structure of the missing data procedure used for SO_2, but incorporates modifications that address the differences between the types of emissions being considered. In the case of NO_x, since the relevant quantity is emission rate, the NO_x missing data routine, including availability calculations, is based on the combined system of NO_x monitor and diluent monitor, and all NO_x missing data substitutions are in terms of emission rate.

Beyond this difference, the physical fact that both flow and NO_x emissions are correlated with load dictated a number of differences between the specifics of the SO_2 missing data routine and the flow and NO_x missing data routines. For the latter two, the conservative values for missing data substitutions would be derived from correlations between load and flow, and between load and NO_x emission rate, based on the data recorded during specified periods during the previous service of the monitoring system.[65] These correlations would be determined using the load-based correlation procedure in Paragraph 3 of Appendix C of the rule. To support this correlation procedure, affected units would establish correlations with load analogous to the previously described sulfur-content correlations for SO_2. Affected units would record hourly load, which would then be divided into load ranges and correlated with the hourly CEMS values for NO_x and flow. This correlation would be established and used to ensure that neither significant overreporting or underreporting of emissions would occur due to the missing data routine. The 90th-percentile value would be calculated on a rolling daily basis for each of the previous 30 or 365 days for use in the missing data routine as described below. Whenever a missing data period occurred which required such a value, the operator would identify the load range during that hour and select the 90th-percentile value from the appropriate range. The specific substitution routines for each tier of the procedure are outlined below; note that the structure of the procedure (availability thresholds, etc.) exactly mirrors the structure of the SO_2 procedures.

If annual NO_x or flow monitor system availability is greater than or equal to 95 percent, and the missing data period is 24

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[65]In developing this method, EPA considered the aforementioned UARG study presenting a correlation method for flow data, "Alternative Procedure for Estimating Volumetric Flow Rate," Technical Memorandum to UARG from Science Applications, Inc., 6/19/91. In EPA's judgment, both flow and NO_x emissions are sufficiently correlated with load to permit the use of correlation procedures like those described in this study.

hours or less, the owner(s) and operator(s) would substitute for each hour in the missing data period the average flow rate or NO_x emission rate recorded during the previous 365 days at the corresponding load range recorded for the missing hour.

If the missing data period exceeds 24 hours, but annual monitor availability is greater than or equal to 95 percent, the owner(s) and operator(s) would substitute for each hour in the missing data period the 90th-percentile recorded flow rate or NO_x emission rate during the previous 30 days at the corresponding load range recorded for the missing hour.

If annual monitor system availability is less than 95 percent, but greater than or equal to 90 percent, the proposed rule provides a three-tiered system for filling in missing data where each tier is related to the length of the missing data period. As mentioned previously, the proposed methods for filling in missing data become more conservative as the length of the missing data period increases.

Tier 1 would apply to missing data periods up to and including six hours. In this tier, EPA proposes to use the average recorded flow rate or NO_x emission rate during the previous 365 days at the corresponding load range recorded for the missing hour.

Tier 2 would apply to missing data periods greater than six hours but less than or equal to 24 hours. In this tier, EPA proposes to use the 90th-percentile recorded flow rate or NO_x emission rate during the previous 30 days at the corresponding load range recorded for the missing hour. Substitute data obtained by this procedure should be somewhat more conservative than the substitute data used in Tier 1, thereby providing an incentive for prompt repair of monitors when they malfunction.

Tier 3 would apply to missing data periods greater than 24 hours. In this tier, EPA proposes to use the 90th-percentile flow rate or NO_x emission rate during the previous 365 days at the corresponding load range recorded for the missing hour. EPA has selected this procedure for filling in long missing data periods to discourage the incidence of such periods and to promote the use of a back-up, portable, certified CEMS as a replacement for a malfunctioning primary CEMS.

As in the case of the SO_2 concentration missing data routine, the Agency believes that this three-tiered approach strikes an appropriate balance between the goal of providing incentives for high monitor availability and the concern that overly conservative methods for filling in missing data might lead to capital expenditures for duplicate monitors by all (or most) affected units. Such expenditures may not be warranted in terms of expected incremental improvements in the accuracy of flow and NO_x emissions data, particularly for low-emitting and moderate-emitting units.

If annual monitor availability falls below 90 percent, the proposed rule would require the use of the 90th-percentile flow rate or NO_x emission rate for the appropriate load range from the previous 365 days, as in Tier 3 above, except that here this maximum rate would be applied to all missing data periods. The Act requires EPA to declare a unit to be operating in an uncontrolled

manner if substitute data satisfactory to the Administrator cannot be provided during missing data periods. EPA believes no satisfactory substitute data exists when annual monitor availability is less than 90 percent, and thus is defining the rate calculated by Tier 3 as equivalent to uncontrolled emissions.

G. CO_2 Emissions Monitoring

Section 821 of the Act states that EPA must require each unit subject to Title IV of the Act to monitor and report annual emissions of CO_2. There are no CO_2 emission limits associated with the monitoring requirement. The emissions data are collected as a means of constructing a database that characterizes CO_2 emissions from electric utilities.

The Agency believes CO_2 emission data for affected units that generate such emissions only through fuel combustion can be obtained with sufficient accuracy for the purposes intended by either: (1) monitoring the CO_2 concentration in the flue gas stream and calculating CO_2 emissions as the product of CO_2 concentration and measured flue gas flow rate, or (2) calculating daily CO_2 emissions based on the measured carbon content of the fuel through fuel sampling and analysis, and the annual amount of fuel combusted. Therefore, today's proposed rule provides the owner(s) and operator(s) of affected units that generate CO_2 emissions only through fuel combustion with the option of either: (1) monitoring CO_2 emissions directly; or (2) using specified procedures and American Society for Testing and Materials (ASTM) methods to calculate CO_2 emissions based on the measured carbon content of the fuel and the amount of fuel combusted.

The Acid Rain Advisory Committee has indicated that either the continuous monitoring of CO_2 emissions or the computation of CO_2 emissions using specified procedures and the ASTM fuel sampling and analysis methods would satisfy the Act's CO_2 monitoring requirements. Some representatives of State agencies have commented, however, that they would prefer the Acid Rain CEMS regulation to be written so as to encourage (but not require) the use of CEMS with CO_2 (instead of O_2) as the diluent gas.[66] While EPA endorses the concept of encouraging the continuous emission monitoring of CO_2, others have noted that such a regulation would effectively eliminate approximately half of today's CEMS from the market. CEMS using O_2 are at least as accurate and reliable as those using CO_2. In fact, there has been a suggestion that O_2 can be monitored more accurately than CO_2, thereby providing better information on diluent gas concentrations.[67] Accordingly, EPA has rejected the recommendation of promoting the use of CO_2 diluent gas monitors in the Acid Rain CEMS regulation.

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[66]E26 - Comments on EPA Issue Papers, N. Wrona, Arizona Department of Environmental Quality, February 15, 1991.

[67]E14 - Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

Affected units equipped with wet FGD or fluidized bed control systems generate CO_2 in the FGD process or in combustion using a fluidized bed system, and would therefore require additional accounting of CO2 emissions. Based on suggestions from the Large Public Power Council and other industry groups, for these units today's proposal requires the owner(s) and operator(s) to (1) monitor the CO_2 concentration in the flue gas stream and calculate CO_2 emissions as the product of CO_2 concentration and measured flue gas flow rate, or (2) calculate daily CO_2 emissions based on the measured carbon content of the fuel through fuel sampling and analysis and the annual amount of fuel combusted, and on the amount of CO_2 generated in the desulfurization process. This latter amount can be calculated based upon the amount of SO_2 removed by the FGD or fluidized bed system.

H. Opacity Monitoring

Many of the units subject to today's proposed regulation already have continuous opacity monitors to comply with existing federal, State, or local opacity regulations.[68] These devices have been in service for a number of years and have performed reliably during that time. Because of this situation, the EPA is proposing that the opacity requirements for the Acid Rain program be the same as those under Subpart Da [40 CFR 60.42 and 60.42(a)], with the exceptions outlined in the next paragraph. Also, under the proposed rule, the owner(s) and operator(s) would be required to submit reports of excess emissions of opacity to the applicable permitting authority.[69] EPA reasoned that this approach to reporting opacity data would result in the best coordination with preexisting air quality programs and the most efficient use of opacity data.[70]

Unlike emissions of SO_2 and NO_x, opacity is not directly related to the creation of acid rain. Moreover, EPA would like to mesh the acid rain program opacity monitoring requirements with those of pre-existing federal, State, and local air quality programs. EPA is therefore proposing to exempt from opacity monitoring gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the back-up fuel. These gas-fired units have very low opacity

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[68]"Opacity" refers to the degree to which emissions reduce the transmittance of light and obscure visibility.

[69]"Excess emissions of opacity" refers to the measured opacity during any six-minute period, or other State-promulgated averaging period, when the applicable opacity limit is exceeded.

[70]"Opacity Monitoring Reports Required by Title IV," L. Paley and S. Viggiani, EPA, March 11, 1991.

levels[71], and few of them are required to monitor for opacity under other federal, State, or local regulations. Nevertheless, where such requirements exist, this exception for Title IV purposes has no effect on the units' need to comply with other provisions of the Act.

EPA is also proposing to exempt wet-scrubbed units from the opacity monitoring requirement, since it is often difficult to measure opacity after moisture is added to the flue gas by a wet scrubber. Under earlier programs such as the New Source Performance Standards (NSPS) program, units with a wet flue gas desulfurization system (wet "scrubber") were required to monitor opacity at the outlet of the scrubber if possible, and at the scrubber inlet if there were significant difficulties with measuring opacity due to moisture. Information from an opacity monitor at the inlet to a wet scrubber would not be useful to the Acid Rain program, although it would still be useful for other programs. Natural-gas-fired units and wet-scrubbed units would not be required to install opacity monitors to meet the requirements of Part 75, but would still be required to meet any other federal, State, or local opacity monitoring requirements.

I. Recordkeeping and Reporting Requirements

Records and reports of continuous emission monitoring data and systems are required to provide the information necessary for assessing compliance with the Act's limitations on SO_2 and NO_x emissions and the proposed monitoring requirements. Such information also is needed by EPA for measuring progress towards the Act's goals of an annual 10 million ton SO_2 reduction and the mandated NO_x reduction and for developing reports to Congress on assessments and program evaluations of the changes in air quality, visibility, and acidic deposition effects resulting from the SO_2 and NO_x reductions.

The proposed rule includes requirements for: (1) monitoring plans, which must be submitted to EPA not later than the date of submittal of the permit required by Part 72, (2) written notifications of monitoring performance certification tests, (3) maintenance of records of emissions and flow, (4) reports of performance certification tests, (5) reports of quality assurance and quality control tests, and (6) quarterly reports of emissions, flow, unit operating status, and monitoring system performance data. The proposed requirements were derived from existing rules for utilities in 40 CFR Part 60 - Subparts D, Da, Db, and Dc and modified to meet the needs of the Acid Rain program.

1. Monitoring Plan for Compliance Plan and Permit

Section 75.23(a) of the proposed rule requires that the designated representative submit a proposed Monitoring Plan to EPA

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[71]E-19, "Issue Paper -- Continuous Emission Monitoring Exemption for Gas-Fired Utilities," Central and South West Services, submitted to the Acid Rain Advisory Committee (ARAC), March 1991.

for each affected unit at the source. A standard form would be required for this submission. The Monitoring Plan would be required to contain information on operating conditions, pollution control equipment, and unit configuration, and on the components of the monitoring systems, including the data acquisition and handling system. This information is necessary for EPA to evaluate the appropriateness of the source's monitoring plan, and would provide the basis for tracking and evaluating the quarterly emission data reports submitted by the affected units to EPA. EPA believes that submission of such information with the monitoring plan would eliminate duplicative submissions of identifying information with each quarterly report, and that permit amendments would be needed only for substantive changes to components or procedures. EPA also believes that such data would allow the Agency to perform analyses of continuous emission monitoring system performance by unit and monitoring system configurations. Such analyses would be used to assess improvements in monitoring technology and to provide information that could assist the regulated community in its selection of appropriate monitoring approaches. Using the form to obtain this information also would ensure that all information submitted is consistent and complete. The standardized format, moreover, should be convenient for sources and should minimize Agency review time. The proposed form is designed to facilitate computerization of the reported information.

2. Notification of Monitoring Performance Tests

Written notification to EPA by the designated representative for the affected unit 30 days prior to conducting performance certification tests and periodic tests for quality assurance is required to provide EPA representatives the opportunity to attend the test. A similar notification requirement is included in the General Provisions to 40 CFR Part 60. A notification required by other State or federal regulations that is substantially similar to that required in the proposed rules would satisfy the proposed notification requirement.

3. Recordkeeping and Reporting of Emissions and Flow Data

Under Subpart Da, sources are required to maintain detailed and complete records of pollutant concentration and opacity measurements (or approved surrogates for these) necessary to assure compliance with the applicable emission standards. However, EPA has required these sources to routinely report only that subset of the information necessary to determine compliance, to assist in regulatory development, or to assist in federal implementation of the Act's requirements. When reports indicate potential noncompliance or supplemental information is needed to determine compliance, EPA can require the sources to submit additional information from records maintained at the facility. Access by others (States, the public) to the records maintained at the source is ensured by the Freedom of Information Act, subject to the requirements of "reasonableness" and the Paperwork Reduction Act.

The proposed rule would maintain this traditional relationship

between the recordkeeping and reporting of CEMS data. EPA would require the routine recording and reporting of data needed to: (1) assess compliance with program's emission reduction requirements; (2) certify the accuracy of measurements and substitute data; (3) allow for operation of the allowance trading market; (4) measure progress towards achievement of the Act's mandated annual reductions in SO_2 and NO_x; and (5) perform Congressionally mandated assessments and program evaluations of the changes in air quality, visibility, and acidic deposition effects resulting from the SO_2 and NO_x reductions.

During development of the proposed rule, there was a general recommendation by ARAC representatives that EPA apply the traditional relationship between recordkeeping and reporting of monitoring data to the Acid Rain program. ARAC representatives also made recommendations on the contents of records to be maintained at the source, particularly regarding the appropriate time period for emissions accounting.[72] EPA has considered differing views on the specificity of report contents and the question of the aforementioned accounting period. One view considered by EPA is that the reporting of hourly emissions data is integral to the Act's requirement "to provide on a continuous basis a permanent record of emissions and flow."[73] An overwhelming majority of the States with whom EPA has discussed recordkeeping and reporting issues already require the reporting of continuous emission monitoring data as hourly (or shorter) averages, and the few with daily averaging time periods believe hourly (or shorter) data would be more useful for assessing compliance.[74] Some utility representatives have said that while they had no objection to a requirement for sources to maintain records of hourly emissions data, they believe routine reports to EPA need not include emissions data more detailed than monthly or quarterly totals.[75] Various ARAC representatives, however, have told EPA that compliance with State regulations to report emissions data as hourly (instead of daily) averages has not been burdensome, and that they would favor standardization between federal and State continuous emission monitoring programs.[76] State agency

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[72]E22 - Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, March 20, 1991.

[73]IID-54, memo by R. Poirot, State of Vermont Department of Environmental Conservation, March 12, 1991.

[74]IIA - 104, State Agency Experience in Recordkeeping and Reporting, March 20, 1991.

[75]Issue Paper on Emissions Monitoring Under Title IV of the 1990 Clean Air Act Amendments, UARG, February 13, 1991.

[76]Acid Rain Advisory Committee (ARAC) Minutes, March 21, 1991.

representatives have also endorsed the concept of reporting consistency between the Acid Rain program and State programs.

The proposed rule would require the reporting of hourly averages for the following types of emissions and flow data: (1) SO_2 and NO_x pollutant concentrations (ppmv); (2) exhaust gas volumetric flow rate (scfh); (3) stack moisture content, volume fraction, where SO_2 pollutant concentration measures are on a dry basis; (4) SO_2 mass emissions rate (lbs/hr); (5) fuel sulfur content (percent, as fired); and (6) NO_x emission rate (lbs/mmBtu). EPA also considered the need to collect SO_2 emissions data on a parts-per-million by volume (ppmv) basis in addition to pounds-per-hour data, which corresponds to the units of the standard (tons per year) for SO_2 under Title IV. EPA has determined that these data are necessary to check the correctness of the units' application of the missing data procedures in the proposed rule. Hourly SO_2 and NO_x emissions measures on a ppmv basis are also essential to the atmospheric modeling required for certain Congressionally mandated assessments and program evaluations.

EPA also believes that the routine reporting of hourly emissions and flow data to EPA would promote more cost-effective overall program implementation, yielding significant cost savings to the government. Some States have reported finding major computational and other software errors during audits.[77] Reporting of hourly data would allow EPA to use computer-based screening routines to "flag" incomplete records, inconsistencies, and indicators of potential compliance problems with the monitoring requirements which, in turn, would enable EPA to target its field auditing resources more effectively. Daily (or longer) accounting periods for the reported emissions and flow data would substantially complicate, or may even prohibit, using these rapid and inexpensive screening procedures. The proposed rule would require the reporting of hourly emissions and flow data in sufficient detail for EPA to identify the probable misapplication of missing data procedures or monitor out-of-control criteria without resorting to audits of the units' on-site records. It would also enable EPA to confirm, quickly and on a continuous basis, the accuracy of units' computational algorithms for combining SO_2 pollutant concentration, flow rate, and (where appropriate) stack moisture content measures into estimates of hourly SO_2 mass emissions (in lbs/hr).

For periods of missing data (i.e., when all or part of the continuous emission monitoring system is not functional or is operating outside the applicable performance specifications), the proposed rule would require the recording, on an hourly basis, and reporting of the method of emissions and/or flow determination. The proposed rule contains codes to assist owner(s) and operator(s) in specifying the method accurately and consistently. Units equipped with add-on SO_2 and/or NO_x emission controls also would be

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[77] IIA-104, State Agency Experience in Recordkeeping and Reporting, 20 March 1991.

required to record, on an hourly basis during periods of missing data, information on the operation and effectiveness of their SO_2 and/or NO_x removal systems. This information, recorded during periods of missing continuous emission monitoring data, would also be reported to EPA.

Under the proposed rule, during each year from 1995 through 1999 units with a qualifying Phase I technology also would be required to record and report the average hourly SO_2 emission rate (lb/MMbtu) at the inlet (i.e., before the emission controls) and outlet. At year end, the owner(s) and operator(s) would report all measurements and calculations necessary to substantiate that the qualifying technology has achieved the required 90-percent reduction (on an annual-average basis) in SO_2 emissions pursuant to Part 72.

In addition to emissions and flow data, the proposed regulation would require recording and reporting of the operating data for unit load and heat input. Unit load data are needed on an hourly basis for the load-based missing data procedure for NO_x emissions and flow. Heat input data are required to evaluate compliance with the reduced-utilization provisions of the Act, and to calculate penalties for NO_x emissions in excess of the standard. Collection of these data will require little additional effort: load information is routinely recorded by utilities, and the required heat input data can be calculated either from the available flow and diluent gas emission data or from oil flow meter and oil sampling/analysis data. Heat input from natural gas would be determined by analysis of each shipment received.

In addition to these hourly data, affected units also would be required to record daily and report the following information: (1) percent monitor availability for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system; (2) results of daily calibration error tests (percent error and number of out-of-control hours) for the SO_2 pollutant concentration monitor, the flow monitor, the NO_x continuous emission monitoring system, and the CO_2 monitor (if used); (3) F-factor value used to convert NO_x concentration to units of the standard (lbs/mmBtu); and (4) total CO_2 emissions (tons/day). Under the proposed rule, the owner(s) and operator(s) also would record hourly and report the unit (boiler) operating time, gross operating load, and heat input (mmBtu). These data are needed for computing percent monitor availability, a critical factor in the proposed missing data procedures, and for determining whether reduced utilization as defined in Part 72 has occurred.

4. Availability and Maintenance of Records

EPA is proposing to allow the Agency and permit authorities to perform periodic inspections of records and equipment to ensure compliance because records of information not otherwise reported are needed for regulatory authorities to evaluate inspection findings. If EPA elected not to require records for inspection at the source, it would result in an inadequate mechanism for verifying compliance and would not be consistent with the statutory requirement for "a permanent record

of emissions and flow."

In addition to the emissions and flow data specified previously to be recorded and reported, the proposed rule would require the owner(s) and operator(s) to maintain records containing hourly averages for the following data on each affected unit: (1) stack gas temperature (°F), and (2) stack gas exit velocity (ft/sec). These data are needed to confirm the representativeness of average gas flow rates measured by the flow monitor. Hourly diluent monitor readings used to calculate NO_x emission rates would also be required. The owner(s) and operator(s) would also be required to maintain records of adjustments, maintenance, and corrective actions performed on pollutant concentration and diluent gas monitors, flow monitors, moisture monitors (if applicable), and the data acquisition and handling system. Such records are already required by Subpart Da as well as many State programs. The proposed rule would require that the records be maintained in a form suitable for inspection at the source for at least two years, which is consistent with Subpart Da.

5. Reports of Performance Certification Tests

Reports of performance certification tests would be required under the proposed rule for initial certification or recertification of the continuous emission monitoring systems, the continuous opacity monitoring system, and any approved alternative monitoring systems. These reports are needed by EPA to determine that the monitoring and data acquisition and handling system equipment required by the proposed rule meet the applicable installation, design, and performance specifications. This reporting requirement is consistent with requirements included in existing reporting requirements for utilities subject to NSPS.

6. Reports of Quality Assurance and Quality Control Tests

The proposed rule would require reports of quarterly and annual quality assurance and quality control tests for the continuous emissions monitoring systems, any approved alternative monitoring systems, and the continuous opacity monitoring system. These reports are needed by EPA to confirm that: (1) emissions and flow data are quality assured, and (2) the missing data procedures and monitor out-of-control criteria in the proposed rule are being applied properly. They are also needed for EPA to evaluate, on an ongoing basis, whether accuracy standards established for the pollutant concentration monitors, the flow monitors, and the continuous emission monitoring systems reflect current technology. This reporting requirement is included in existing reporting requirements for utilities subject to NSPS.

7. Quarterly Reports

EPA is proposing quarterly submissions of monitoring data. In selecting the proposed standards, EPA also considered more frequent reporting, such as real-time telemetry or daily reporting. However, reports submitted by affected units must be screened for accuracy and completeness prior to entry into the EPA databases, and therefore such reporting was rejected as impractical, particularly during the startup years of the program.

Less frequent reporting, such as annual submissions, would not provide EPA with the necessary information to identify a potential problem at the source within a reasonable timeframe. Annual submissions were also rejected because of the administrative difficulty and costs of processing, quality assuring, and assessing an entire year's worth of data for hundreds of affected units in Phase I and thousands of affected units in Phase II.

Quarterly reports of emission data for SO_2, NO_x, volumetric flow, CO_2, and other information are required for EPA to assess compliance with the proposed monitoring requirements and with other provisions of the Acid Rain program. Quarterly reporting provides the needed information within a timeframe that allows EPA to manage and assess the information in a timely manner. Such reporting also is consistent with other current federal and State requirements. For these reasons, quarterly reporting was selected for the proposed rule.

8. Electronic Reports

The heart of the Title IV program, the allowance trading program, will be an electronic system in order to maintain timely and accurate records of allowance holdings and trades available to all trading participants. EPA intends to enter monitoring data into databases using the same computer facilities as for the trading information. In addition, many utilities are already experienced in electronic reporting of monitoring data through various State programs, such as those in Pennsylvania and Illinois. The concept of electronic reporting for this proposed rule also has been endorsed by the Acid Rain Advisory Committee, which believes that this type of reporting will reduce burden, minimize errors, and ensure the viability of the "true-up" period for end-of-year allowance and emission balancing. EPA believes that electronic reporting is also the most practical way to implement the program for the utilities as well as EPA. Nevertheless, EPA requests comment on whether electronic reporting should be required, or whether other reporting formats should also be allowed.

The proposed rule would require the owner(s) and operator(s) to electronically report the required information as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or by a modem. To facilitate electronic reporting for all affected units, EPA plans to develop a guidance document containing user-friendly information on electronic format and standardized forms. This document will be available for distribution shortly after the promulgation of the Acid Rain CEMS regulation.

9. Reporting Party

Consistent with the provisions of 40CFR Part 72, the proposed rule specifies that the designated representative will be responsible for submitting quarterly reports of recorded emissions and flow data and reports on the performance of Phase I qualifying technologies on behalf of the owner(s) and operator(s). The owner(s) and operator(s), however, would be responsible for the more technical certification and periodic quality assurance tests of the continuous emission monitoring system and its components. EPA requests comment as to whether all reports should be the

responsibility of a single person, namely the designated representative, even though this individual may not be knowledgeable of site-specific conditions and continuous emission monitoring instrumentation.

J. Alternative Monitoring Systems

In general, the Act requires affected units to install and operate continuous emission monitoring systems for monitoring SO_2 and NO_x emitted into the atmosphere. However, it also allows units to use an alternative monitoring system for monitoring one or both of these emissions, or a component of such emissions (e.g., SO_2 concentration, flow), provided that EPA can certify that the data produced by the alternative monitoring system is equivalent to that from a CEMS on four criteria: precision, reliability, accessibility, and timeliness. EPA defines the applicable criteria as follows: (1) precision - the closeness of the emissions measurements (or indirect determinations of emissions) to the true emissions; (2) reliability - the ability to operate within the prescribed performance specifications and quality assurance standards without interruptions in operation for a specified number of hours each year; (3) accessibility - the ability to generate the required data in the form needed to meet recordkeeping and reporting requirements; and (4) timeliness - the ability to record and issue the required data within a stipulated time period. To preserve the orderly functioning of the allowance system and to ensure that the mandated emissions reductions are achieved, the Act also gives EPA the authority to set limitations on the use of alternative compliance methods by units equipped with alternative monitoring systems.

1. Demonstrations of Equivalency to CEMS

Under the proposed rule, EPA would use the performance of certified SO_2 pollutant concentration monitors, flow monitors, and NO_x continuous emission monitoring systems, defined in the previous sections, as benchmarks for approving or rejecting proposals for alternative monitoring systems. Thus, to qualify under the precision criterion, the difference between measurements from an alternative monitoring system for measuring SO_2 concentration or flow and a certified SO_2 pollution concentration or flow monitor would be required to fall within defined statistical limits. Three statistical tests would be used for this comparison: (1) a t-test to assess the systematic error; (2) an F-test to assess the random error; and (3) a correlation analysis, supported by time-series plots, to determine how well the proposed alternative monitoring system tracks the CEMS benchmark measurements over time. The same approach would be used for evaluating an alternative monitoring system for measuring NO_x emissions on the precision criterion, except that the benchmark would be a certified NO_x continuous emission monitoring system.

Similarly, to meet the reliability criterion, the alternative system would be required to match or surpass the appropriate certified benchmark in terms of annual availability and ability to meet performance specifications and quality assurance requirements. In order to satisfy the accessibility and timeliness criteria, an

alternative system would be required to match the capabilities of the CEMS in being able to record the requisite monitoring data on an hourly basis and to report results within 24 hours.

Monitoring systems proposed as alternatives to CEMS will be reviewed on a case-by-case basis by EPA according to the criteria and evaluation procedures summarized above and detailed in Section 75.21 of the regulation. Approval will be contingent on the applicant's providing substantial, long-term statistical evidence that the precision, reliability, accessibility, and timeliness offered by the proposed alternative is equivalent or superior to CEMS.

EPA believes that these requirements will permit affected units to implement alternative monitoring systems where they are justified. In addition, by using CEMS as a benchmark for judging alternative systems, the proposed rule would establish a framework in which technological innovations offered by alternative systems could establish improved and more cost-effective emission monitoring standards in the future.

2. Proposed Exceptions for SO_2 CEMS: Gas-Fired Units and Oil-Fired Units

Under the proposed rule, EPA would offer two prescribed excepted monitoring methods for estimating SO_2 mass emissions per unit time as an alternative to CEMS for gas-fired and oil-fired units. Gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the backup fuel would be allowed to use an excepted method due to the good performance of that method with respect to the four aforementioned criteria (precision, reliability, accessibility, and timeliness), and to the de minimis nature of the SO_2 emissions from this category of affected units. In addition, units which combust oil, diesel fuel, or any combination of oil, diesel fuel, and gas, would be allowed to use an excepted monitoring method for determining SO_2 mass emissions due to the relative homogeneity of oil with respect to sulfur content, the effectiveness of the method in obtaining representative samples, and the resulting good performance of the method with respect to the aforementioned criteria.

In the case of the gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the backup fuel, according to EPA's National Allowance Database the 525 existing units of this type emitted only 7600 tons of SO_2 in 1985, yielding a unit average of less than 15 tons annually.[78] In addition, only six of the 525 units emitted more than 100 tons in 1985. Under the proposed excepted monitoring method for these units, there would be no requirement to continuously monitor SO_2 emissions when the unit is combusting

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[78]E24 - Baseline Tons of SO_2 (1985) for Selected Categories of Affected Units Under Title IV, Acid Rain Advisory Committee (ARAC).

natural gas. Based upon the typical amount of sulfur found in natural gas measured by ASTM methods for analysis, these units will emit less than 100 kg of SO_2 annually while combusting natural gas.[79] Representatives from utilities, State agencies, and environmental groups concur with EPA's assessment that such emissions would be non-existent or negligible.[80] When the unit is combusting oil, either in-line oil flow meters would be required to continuously monitor the amount of oil consumed, or the highest value from a series of daily composite samples would be used to monitor the sulfur content of that oil and estimate SO_2 mass emissions (in lbs) hourly.

Representatives of the gas-fired utility industry have provided EPA with a case study which proposes that, for gas/oil-fired units combusting no less that 90 percent natural gas, in-line oil flow meters and oil sampling procedures can provide a level of precision and reliability close to a continuous emission monitoring system.[81] These case studies indicate that using specified ASTM procedures for oil sampling and analysis, the proposed excepted monitoring method for SO_2 emissions meets the random error criteria (discussed previously) for precision. Although no data are available on the long-term reliability of the proposed method, these studies imply there would be little or no data loss when the proposed oil flow monitoring and oil sampling procedures are used for ten days a year, which would be the typical usage for these units.[82]

For gas/oil units using less than 90 percent gas in their combustion mix, or for units firing exclusively oil or diesel fuel, a second excepted monitoring method is proposed as an alternative to CEMS. This exception is based on the relative ease of obtaining representative samples of these fuels, and on the fact that fluid fuels, such as natural gas or oil, are much more homogeneous in sulfur content than coal. Preliminary data comparing oil sampling and analysis and CEMS values implied that these two methods track each other.[83] Data from oil sampling and analysis protocol

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[79]ASTM D3031, "Standard Test Method for Total Sulfur in Natural Gas.

[80]E22 - Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, March 21, 1991.

[81]Presentation materials on continuous emission monitors for gas/oil units <10% oil, submitted to ARAC Emissions Monitoring Subcommittee, J. R. Smith, Houston Lighting and Power Co., April 25, 1991.

[82]Data from Barney Davis Plant, Central Power and Light.

[83]"Preliminary Analysis of Oil Sampling and Analysis and Continuous Emission Monitoring," Kilkelly Environmental Associates, July 15, 1991.

consistently produce higher emission rates than the CEMS data. Accordingly, EPA proposes that units firing oil, natural gas, diesel fuel, or a combination of these may use the more precise of the proposed excepted procedures in Appendix D of Part 75. EPA expects more conclusive data soon to be available upon the completion of a demonstration of several emission monitoring methods for SO_2 from consumption of oil by Consolidated Edison of New York.

The proposed monitoring methods have three main features: accurate metering of oil flow, as-fired oil sampling, and procedures specified by ASTM for the analysis of oil for sulfur content and density. EPA chose to limit the accuracy of fuel flow meters to +/- 2 percent to ensure accurate and precise emissions data from the entire process after fuel flow data and oil sampling and analysis errors would also be combined. EPA also considered selecting an accuracy of +/- 1 percent for oil flow meters, since several types of meters can meet this requirement.[84] However, the Agency noticed that the looser 2 percent accuracy specification would allow all of the commonly-used flow meter types, including some of the less expensive flow meters, without greatly affecting the overall accuracy of the process. As suggested by the gas-fired utility industry, EPA would require oil flow meters to be calibrated annually.[85]

For this approved excepted method, EPA is proposing an oil sampling protocol based on ASTM methods that is most likely to provide precise, accurate data. The Agency had some concern that the variability of sulfur in oil over the course of a day might allow an underestimation of emissions if oil samples were taken only once daily. This would be especially likely in cases where an operator purchases individual shipments of oil at the lowest price. In such cases, the sulfur content of the oil could vary significantly within one day as the unit began to burn the new supply of oil. In order to ensure that oil samples are truly representative of the amount of sulfur in combusted oil, EPA is proposing automatic sampling on an hourly basis in proportion to the rate of oil flow for units firing more than 10 percent oil. In addition, daily manual oil samples are allowed for gas-fired units. Since a single, manual daily sample might be lower in sulfur content than the average for the entire day, an operator taking daily oil samples would be required to use the highest sulfur content of the previous 30 daily samples to prevent underestimation.

There are many different methods for analyzing oil for density

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[84]Table 6-1, Chapter 6, Flow Measurement Engineering Handbook, R. W. Miller.

[85]Presentation materials on continuous emission monitors for gas/oil units <10% oil, J.R. Smith, Houston Lighting and Power Co., submitted to the Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee, April 25, 1991.

and sulfur content. EPA chose a variety of ASTM methods for analysis of oil in order to allow the greatest flexibility. The flexibility afforded by these provisions would allow in-house utility laboratories or outside laboratories to analyze oil using either manual or automated methods.

The proposed excepted monitoring method would provide hourly SO_2 emissions data by the following day, thus achieving the same accessibility and timeliness as for CEMS.[86] Industry representatives have suggested that this "next day" turn-around time requirement may sometimes be impractical for units located in remote areas and for units that must send out oil samples for analysis. Other timeliness requirements, ranging from three to nine days, have been suggested. Further comment is solicited on this point.

EPA has received a proposal for additional procedures to determine SO_2 emissions from oil-fired units from members of the oil-fired utility industry.[87] These sets of procedures require oil-fired units to use an oil flow meter but allow the flexibility of less precise, less continuous samples in exchange for using a default value for fuel sulfur content which will yield conservatively high emission estimates. A continuous method of oil sampling such as frequent automated sampling or continuous drip sampling would be expected to be as precise as a continuous emission monitoring system. A single, manual daily oil sample might be less representative than a continuous sample; thus, an operator taking daily oil samples would use the highest sulfur content measured in the past 30 days to calculate emissions of SO_2 to prevent underestimation. EPA has considered this procedure and has proposed its use for gas-fired units. The additional flexibility of allowing manual sampling would be especially useful for this class of units which fire oil for a short period of time each year, since they would not need to purchase special sampling equipment for use only during a few days each year. EPA solicits comment regarding the appropriateness of this monitoring method, and regarding the possibility of extending it to diesel- and other oil-fired units. In addition to these two procedures, the Class of '85 proposal also includes the option of using the maximum permitted oil sulfur content as a default sulfur value at all times for units with such a permit limitation. Gas-fired units and oil-fired units operating for 400 hours a year or less would be able to monitor the changes in sulfur content and mass of oil in storage, rather than monitoring and sampling the fuel as it is about to be burned. EPA has considered these options but has concerns about their administration, as well as the clear departure from the statutory requirements for monitoring methods with the same

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[86]This would be equivalent to a daily calibration error test.

[87]"Class of '85, Proposed Alternative Emissions Monitoring System for Oil and Gas Fired Affected Units," June 6, 1991.

precision, reliability, accessibility, and timeliness as CEMS.

EPA has reviewed and rejected proposals for alternatives to CEMS for the monitoring of NO_x emissions by gas-fired units combusting no less than 90 percent natural gas annually. These units may have non-negligible NO_x emissions and are not exempted from the NO_x continuous emission monitoring requirements of this Part. Further, EPA has identified no alternative monitoring system for NO_x emissions that even closely approximates a CEMS on the criteria required by the Act. The proposed alternative monitoring methods for NO_x would provide data that would not be quality assured until the next year when a test would be conducted. This clearly does not meet the requirement for timeliness of data. EPA also has received no alternative NO_x monitoring data comparing readings from a proposed protocol with those from a NO_x CEMS.

VII. Part 77 - Excess Emissions

A. *Background and Purpose.*

Part 77 of today's proposal sets forth the requirements for excess emissions offset planning and offset penalties, pursuant to Section 411 of the Clean Air Act, as amended (the Act). As a general rule Title IV of the Act is intended to provide maximum flexibility for sources to determine the means by which they would comply with the sulfur dioxide and nitrogen oxides emissions limitations of the Acid Rain program. However, Congress deemed the statutory goal of reducing acid deposition precursors as paramount.

Section 411 eliminates any financial benefit owners and operators of affected sources might otherwise derive from exceeding their emissions limitations, by imposing an automatically due and payable statutory penalty for each ton of excess sulfur dioxide or nitrogen oxides emissions emitted by an affected unit in a calendar year. (See, Section 411(a) and (c).)

These penalties are in addition to penalty liability any source risks under other enforcement provisions of the Act (Section 411(e)). In addition, the Administrator is required to deduct sulfur dioxide allowances to the extent an affected unit has experienced excess emissions of sulfur dioxide in any calendar year. (See, Section 411(b).) (This obligation is in addition to other allowance deductions that would be required for, e.g., violations of Phase I Extension plan's provisions under Section 404(d)(7), or the reduced utilization planning provisions.)

Finally, Congress underscored the severity with which it viewed violations of Acid Rain program requirements, including excess emissions, by providing specifically that nothing in Section 411 limits or affects the liability that a source might have under the Act's other enforcement authorities, including Section 113 which authorizes the imposition of civil and criminal sanctions for violations of the Act. (See, Section 411(e).)

Given the degree of flexibility otherwise afforded sources under Title IV, the Agency proposes to ensure strict compliance by affected sources with the emissions reduction requirements of the Acid Rain program, and the excess emissions offset and penalty requirements of Section 411 of the Act. Consistent with the program generally, however, the proposal does afford flexible excess emissions offset planning opportunities for sources.

Today's proposal includes several provisions intended to ensure the deterrent effect of these sanctions. These are discussed in greater detail below, but a few deserve special mention. With regard to excess emissions penalties, EPA proposes to encourage compliance with the automatic nature of the penalty obligation by including an interest adjustment as part of the penalty to account for any delays in payment. Other provisions that would ensure the deterrent effect of the program include the provisions in 40 CFR Parts 77 and 72, imposing liability on multiple-owners, operators, and the designated representative of

a violating unit, and on all owners, operators, and designated representatives of affected units governed by an approved multi-unit compliance plan. These provisions lend a self-monitoring element to the program that is critical to ensuring compliance.

EPA considered whether to require offset plans for excess emissions of nitrogen oxides. This proposal does not require nitrogen oxides offsets because they are not specifically required by Section 411 and there is no allowance system that would enable ease of accounting for such offsets. Sources violating the nitrogen oxides emissions reduction requirements of the Acid Rain program would, however, be subject to the full array of enforcement authorities under the Act, including the authority of the Agency to issue appropriate remedial orders necessary to protect the environment and deter future violations.

The proposed rule is organized as follows: Section 77.0 describes to whom the requirements of 40 CFR Part 77 apply. Section 77.1 defines terms used in 40 CFR Part 77. Section 77.2 specifies the sulfur dioxide excess emissions offset planning requirements of this part. Section 77.3 describes the actions the Administrator will take on proposed offset plans. Section 77.4 and Appendix B of this part specify requirements for the imposition, calculation, and payment of excess emissions penalties. Sources would be obligated to calculate penalties in accordance with a specified formula. In addition, as required by the Act, the rule provides that each year EPA will publish adjustments to the statutory base penalty amount of $2,000 per ton for inflation using the Consumer Price Index. The rule specifies the formula EPA will use to calculate the adjusted penalty. The rule provides, consistent with Section 411 of the Act that penalties would be required to be paid to the U.S. Treasury, without demand, and that interest would be required to be paid on tardy payments. Section 77.5 specifies the proposed requirements for the submission of information, including signatory requirements, and cites the relevant Federal and State authorities, as well as the recordkeeping requirements.

B. *Applicability.*

Section 77.0(a) explains that the requirements of this part would apply to owners, operators, and designated representatives of affected units under the Acid Rain program. This is consistent with the statutory provisions which specify that these persons are responsible for ensuring compliance with the emissions reduction obligations of the program.

Section 77.0(b) restates the savings clause found in 40 CFR Part 72 and other parts of today's proposal, providing that whenever a requirement or prohibition in 40 CFR Parts 70-78 was worded as applying to an affected source or an affected unit, or to the designated representative of an affected source or unit, it would also apply to each owner and operator of the affected source or unit. This is a fundamental liability concept underlying the Acid Rain program, which underscores the owners', operators', and designated representatives' shared responsibility and liability for ensuring that violations are remedied. Thus,

while the designated representative is the primary point of contact with EPA on the holding and transfer of allowances, permitting, and compliance reporting in the Acid Rain program, owners and operators are not immunized by this relationship, and are equally liable for ensuring compliance with the requirements of the program by the affected source or unit. The designated representative serves a specialized fiduciary role (e.g., a special category of operator) essential to the program's inherent flexibility. Owners and operators, however, remain primarily responsible for ensuring compliance with the Act's requirements. This liability is provided for in Section 411 and elsewhere in Title IV of the Act. (See, for further discussion, the 40 CFR Part 72 preamble and rule.)

Consistent with Section 411(e) of the Act, Section 77.0(c) states that nothing in 40 CFR Part 77 would limit or otherwise affect the enforcement and investigatory authorities contained in Sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act. These include administrative enforcement, and a variety of civil and criminal judicial enforcement authorities. Section 411 of the Act specifies the strict liability under the program that results from excess sulfur dioxide and nitrogen oxides emissions. The liability is automatic and requires no enforcement action. Section 77.0(c) of the proposed rule would, thus, codify the statutory savings clause that, notwithstanding the obligations and remedies of 40 CFR Part 77, violators risk further enforcement for excess emissions pursuant to the full range of investigatory and enforcement authorities of the Act. The remedies available under Sections 112(r)(9), 113, 114, 120, 303, and 306, of the Act are, moreover, not to be diminished in any way by any remedy available under 40 CFR Part 77.

C. *Definitions.*

Section 77.1 provides that, for 40 CFR Part 77, the terms would have the same meaning as that given in the Act, in 40 CFR Parts 72-78, and in Section 77.1 of the rule, as listed. Language incorporating the definitions of the other Acid Rain program regulations and the Act, by reference, appears in each part of the program rules, and is intended to assist in preserving the program's integrity. The terms defined in Section 77.1 of today's proposal specifically are those central to a clear understanding of 40 CFR Part 77. One definition deserves special mention. The term "ton" is defined as including any ton or fraction of a ton of emissions. This is particularly necessary with regard to sulfur dioxide emissions since fractions of allowances are not provided for in the program. In addition, it is more protective of the environment, ensures maximum deterrence of violations, and obviates any disputes regarding the total tons of offsets that must be achieved.

D. *Sulfur Dioxide Excess Emissions Offset Planning.*

Section 77.2 sets forth the requirements related to sulfur dioxide excess emissions offset planning. Section 411(b) provides that for each ton of sulfur dioxide emissions in excess

of an affected unit's Acid Rain program sulfur dioxide emissions limitation (i.e., the allowances held for use by the unit for the calendar year in the unit's Allowance Tracking System compliance subaccount), the unit must offset the excess emissions with allowances. Today's proposal requires that the offsets be achieved by a deduction of one allowance from the affected unit's Allowance Tracking System account established pursuant to 40 CFR Part 73 for each excess ton of emissions. Section 411(b) also provides that the allowances must be offset in the year following the year when the excess emissions occurred, unless the Administrator approves a longer offset period. Accordingly today's proposal specifies that, unless the designated representative for the unit submits an approvable excess emissions offset plan providing otherwise, allowances would be deducted by the Administrator from the allowances contained in the affected unit's Allowance Tracking System compliance subaccount account for the year in which excess emissions occurred.

Conceptually, excess emissions offset plans are treated in 40 CFR Part 77 as similar to a 40 CFR Part 72 compliance plan. Thus, an approval by the Administrator of an offset plan would revise the previously approved permit for the affected source. An excess emissions offset plan would have to be submitted to EPA by the designated representative of the affected unit that had emissions in any calendar year in excess of its sulfur dioxide emissions limitation (i.e., the allowances held for use by the unit for the calendar year, in the unit's Allowance Tracking System compliance subaccount). The plan would have to specify a methodology for offsetting the excess emissions in as expeditious a manner as practicable.

Section 77.2(a) provides that any affected unit that emits sulfur dioxide in any calendar year in excess of its sulfur dioxide emissions limitation for that year, would be required to compensate for those excess emissions during the offset period approved by the Administrator, by an amount of not less than the tons of excess emissions that occurred during that year. Section 77.2(a) would require that the sulfur dioxide emissions limitation would be determined each year based on the number of allowances held in the affected unit's Allowance Tracking System compliance subaccount, as provided in 40 CFR Part 73 of today's proposal.[1] Section 77.2(a) also restates the requirement set forth in Section 411(b) of the Act that, for each ton of sulfur dioxide emissions in excess of an affected unit's emissions

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[1] It should be noted that Title IV provides a default in the event the Acid Rain Program allowance system were to fail. The Act provides that, in the absence of an allowance program, each unit's sulfur dioxide emissions limitation is the tonnage equivalent of the allowance allocations for the unit pursuant to sections 404 and 405 of the Act. 40 CFR Part 77 has been worded to accommodate any such default.

limitation, the Administrator is required to deduct one allowance from the affected unit's Allowance Tracking System account (unless another unit is designated to provide the offsets) (See, further discussion below.)

Section 77.2(b) restates the statutory mandate that, within 60 days after the end of the calendar year in which excess emissions occurred at an affected unit, the designated representative would have to submit a proposed excess emissions offset plan to the Administrator. The rule proposes that the plan be sent to EPA Headquarters, to the Region for the State where the affected unit is located, and to the State in which the affected unit is located. The requirement to provide permitting States with copies of excess emissions offset plans is proposed to help close coordination since these plans, once approved, would amend the permit. In addition, the requirement to copy both EPA Headquarters and the appropriate EPA Regional Office is included to avoid delay, and to provide flexibility for the Agency and maximum convenience for the affected source during the process of responding to excess emissions situations. (See, discussion of "team approach" in preamble for 40 CFR Part 72).

Section 77.2(e) would require that the plan describe the measures proposed to be taken by the source to offset the excess emissions, including:

- The number of offset allowances required to be deducted from the Allowance Tracking System account of the unit or units providing the offsets; and
- A schedule, with appropriate increments of progress: for reducing sulfur dioxide emissions and deducting the offset allowances from the Allowance Tracking System account for the unit or units responsible under the plan; for achieving the offsets, including specification of the identification numbers of the allowances to be deducted and specification of when they should be deducted; for obtaining additional allowances necessary to ensure continuous compliance; and for taking corrective actions.
- The serial number of the allowance deductions (if the designated representative elects to specify the deductions) using the Compliance Deduction Form as provided for in 40 CFR Part 73.

Additionally, Section 77.2(e)(5)(ii) would require, consistent with 40 CFR Part 73, that each sulfur dioxide excess emissions offset plan include a certification that no allowances would be transferred during the offset period from the Allowance Tracking System account for any unit responsible for the required offsets that are needed for offsetting the excess emissions or that might cause any further excess emissions of sulfur dioxide at the unit.

Section 77.2(c) proposes that, except as discussed below, separate excess emissions offset plans would be required to be submitted for each affected unit with excess emissions. Since each affected unit would be subject to, and would be required to be operated in compliance with, the sulfur dioxide emissions

limitations of the program, each affected unit is viewed as a separate entity relative to excess emissions. Even where one representative is designated for two or more affected units, the rule would provide that each affected unit with excess emissions would be subject to a separate excess emissions offset planning requirement.

Section 77.2(d) proposes that the one exception to the separate excess emissions offset planning requirement would be units governed by a multi-unit compliance plan approved pursuant to 40 CFR Part 72, Subpart D. These include substitution plans, reduced utilization compensating unit plans, Phase I Extension control unit plans, and plans for units with a common stack monitor. The basis for this exception is that units operating under a multi-unit compliance option would have interdependent compliance obligations.

For example, units operating under a common stack plan are constrained by an inability to differentiate emissions between or among those units monitored at the common stack. In view of this problem, the Agency has proposed in 40 CFR Part 75 to treat units that share a common stack monitor as one unit for purposes of calculating emissions unless a demonstration is made certifying separate monitors for each unit. In addition, 40 CFR Part 72 proposes that such units would be governed by a common-stack plan. Consistent with this approach the Agency believes it is appropriate and necessary to require one excess emissions offset plan from the combination of units that are governed by a common stack plan. Thus, if the combined emissions exceed the aggregate allowances held for the units governed by the common stack plan, all of the units whose emissions were monitored at the common stack would have to be treated as being in noncompliance. Moreover, since units with emissions ducted through and monitored at a common stack cannot be assigned separate emissions limitations, all the owners and operators of all the units using the common stack would be liable for the excess emissions.

Similarly, in the case of units operating under any other multi-unit compliance plan, the duty to offset exceedances of the sulfur dioxide emissions limitations as provided by the plan at any one unit would have to be shared by all the units governed by the plan. Otherwise, since an individual unit's ability to comply depends on operations at the other units under the plan, defenses to excess emissions offset planning requirements could be raised based on disputes concerning the actions by the other interdependent units. Under a substitution plan, for example, an excess emissions situation could be the result of disputes between majority and minority owners concerning the transfer of allowance allocations from the substitution unit's Allowance Tracking System account to the originally affected unit's account. Such disputes cannot be allowed to delay the excess emissions offset planning obligation. By making each owner and operator of a unit governed by a multi-unit plan liable for the offset planning obligation, this section would build into the

program a self-regulating element that should minimize, if not totally eliminate, such problems.

Section 77.2(e) specifies the excess emissions offset plan content requirements. Section 77.2(e) would require that each proposed excess emissions offset plan be submitted on the standard form proposed in Appendix A of 40 CFR Part 77. The information required by the standard form would ensure that essential information identifying the designated representative for the affected unit with excess emissions and information about each affected unit is included in the plan. The submission would also have to be signed by the designated representative for each unit governed by the plan. These requirements would be consistent with the general approach for Acid Rain program submissions proposed in 40 CFR Parts 72, 73, and 75 and are intended to minimize the burden on sources making submissions, and increase the Agency's ability to rely on each submission as being fully authorized by the source.

Such plan would have to include certifications concerning the extent of excess emissions, including a description of how and why the excess emissions occurred, and of any corrective actions that were taken to prevent or minimize the extent of excess emissions. This information would assist the Agency in evaluating the adequacy of a proposed excess emissions offset plan including the source's ability to prevent excess emissions in the future.

The rule would also require that each excess emissions offset plan include a description of the measures that would be taken to offset the exceedance and a schedule with increments of progress for achieving the offsets. This description is required even if the unit's plan entails only buying extra allowances on the open market to cover the amount of the unit's emissions. The plan would have to include a demonstration that the schedule results in offsets as expeditiously as practicable, taking into account electric reliability. EPA solicits comment on appropriate criteria for evaluating electric reliability. One criteria the Agency is considering is system reserve margin.

Section 77.2(e) also addresses proposed excess emissions offset plans that rely on one or more of the Acid Rain compliance options authorized under 40 CFR Part 72, Subpart D (e.g., reduced utilization and substitution plans). If the designated representative wanted to propose to offset excess emissions occurring during any year by relying on a compliance option authorized under Subpart D of 40 CFR Part 72, the excess emissions offset plan would have to include the appropriate standard form required by 40 CFR Part 72 for the compliance option chosen. If the compliance option chosen involved multiple units, the plan would have to designate any compensating or substitution unit, and a schedule for achieving the required offsets in coordination with the designated unit. For example, the schedule should specify deadlines for reducing utilization of the unit responsible for the excess emissions and for shifting load to a compensating unit. Finally, a certificate of

representation establishing the authority of the designated representative(s) with regard to all the units covered by the multi-unit plan would have to accompany the proposal to ensure accountability. The rule specifies that any plan relying on an Acid Rain compliance option of 40 CFR Part 72, Subpart D, would have to result in reductions equal to those that would be required by a standard excess emissions offset plan providing for allowance deductions directly from the Allowance Tracking System account for the affected unit responsible for the excess emissions.

Section 77.2(e) also proposes that, if the designated representative seeks to offset excess emissions by installing a technological means of pollution control, the excess emissions offset plan would have to specify increments of progress for installing and commencing operation of the equipment, and include a showing of technological adequacy. This would be essential information for a source to be able to demonstrate that the offsets would be achieved as expeditiously as practicable.

Section 77.2(e) would also require that the excess emissions offset plan list and describe the provisions of the affected unit's permit and approved compliance plan that would be revised by the proposed excess emissions offset plan, if approved. In order to determine the merits of an excess emissions offset plan, it is necessary that the Administrator and other interested persons be able to understand where and how the permit and approved compliance plan would be changed. This information would serve to ensure that proposed changes to the permit and compliance plan by the excess emissions offset plan do not yield unanticipated results.

The rule would also require that the excess emissions offset plan include a schedule for the submission of progress reports. Quarterly progress reports, due in accordance with the quarterly reporting schedule of Section 72.401(b), would be required from the designated representative, beginning with the calendar quarter (April 30 of each year) following the date on which an excess emissions offset plan is due, and concluding in the quarter in which the offsets are achieved. The Agency considered whether reporting should be driven by the increments but determined that a standard reporting approach would add to ease of administration and ensure consistent treatment of sources. These reports would be required to include a description of the work accomplished; a demonstration that interim milestones were achieved; a summary of remaining work to be performed; and proposed adjustments, if any, to the schedule.

In addition, a final report and supporting documentation would be required, to be included in the annual report required by 40 CFR Part 72, within 30 days after the end of the year during which the offsets were achieved in full. The final report would include a description of the work performed in accordance with the excess emissions offset plan, the date that the offsets were achieved, and the number of tons of offsets achieved. To ensure that each designated representative submitting a report

under this section is fully aware of the liability for false submissions, Section 77.2(e) would also require that each report be signed and contain the standard certification regarding the truth and accuracy of submittals that would be required under 40 CFR Part 72. This is necessary so the Agency can accept the submission as reliable.

E. *Administrator's Actions on Offset Plans.*

Section 77.3 specifies the procedures for EPA action on proposed excess emissions offset plans and the effect of such plans and Administrator actions. Subsections (a) through (c) would require the Administrator to review each proposed excess emissions offset plan for administrative and substantive completeness and issue a determination of completeness to the affected source within 30 days of receipt, similar to proposed Section 72.72. Thereafter, the Administrator would be required to act on a proposed excess emissions offset plan within 6 months of its receipt. This again tracks the 40 CFR Part 72 procedures. Subsection (d) specifies the steps the Administrator would take to propose an offset plan.

Subsections (e) through (h) would provide an opportunity for public comment on an excess emissions offset plan. It is intended that such public comment opportunity would be afforded by the Administrator, following procedures similar to those that would be required by 40 CFR Part 72, Subpart J, Section 72.301 (permit modification procedures), before the Administrator would take action on a proposed excess emissions offset plan. The opportunity for public comment is being proposed since the excess emissions offset plan would, on approval, alter the requirements applicable to an affected source under the approved operating permit during the offset period, and would revise any inconsistent permit provisions.

Once approved, an excess emissions offset plan would be incorporated into the permit as an administrative amendment under Section 72.303 of today's proposal. (See, further discussion below regarding Section 77.3(l)). This is appropriate since an opportunity for public review and comment on the proposed excess emissions offset plan would have already been afforded by the Administrator under 40 CFR Part 77. It would, therefore, be redundant to afford an additional opportunity for public comment under 40 CFR Part 72. However, it is important that interested States and anyone who commented on the original permit receive notice of the excess emissions offset plan as approved. The administrative amendments procedure of 40 CFR Part 72 would afford such notice.

Subsections 77.3(i) through (j) describe how the Administrator could approve the excess emissions offset plan as submitted, in whole or in part with appropriate revisions, or conditionally with expeditious deadlines for the conditions to be met not later than the end of the year. Otherwise, the Administrator could disapprove the plan, and deduct allowances or issue such order as is necessary to achieve the offsets. In taking any such action, the Administrator would have to specify

an excess emissions offset period for achieving the emissions reductions in full.

Section 77.3(k) would require the Administrator to deduct allowances, in accordance with the approved excess emissions offset plan, equal to the tons of excess emissions. Section 77.3(k) restates the requirement in Section 411(b) of the Act that the allowances must be deducted in the year immediately following the year when the excess emissions occurred, unless the Administrator approves a longer offset period. Accordingly, Section 77.3(k) would require that, in the absence of an approvable excess emissions offset plan, allowances be deducted from the affected unit's Allowance Tracking System account beginning with the unit's compliance subaccount. This subaccount contains only those allowances currently useable by the unit. (If allowances in the compliance subaccount are insufficient, allowances would be deducted from future year subaccounts.)

The rule would also authorize that allowance deductions be spread-out over a specified period greater than one year. However, this would require a showing by the affected source, to the Administrator's satisfaction, that deducting the entire amount of the allowances required to offset the excess emissions during the following calendar year would interfere with electric reliability. It should be understood that a high hurdle is intended and that such a showing would be extremely difficult to make. This is particularly so in the case of sulfur dioxide since the affected source would have to also demonstrate that allowances were not available on the market. The overriding concern sought to be addressed by this limitation is the need to ensure expeditious offsets, consistent with the annual reduction program contemplated by the statute. Moreover, the Agency wants to avoid protracted remedies since they would tend to compound compliance problems.

Today's rule, however, proposes to authorize excess emissions offset plans that rely on one or more of the Acid Rain compliance options specified in 40 CFR Part 72, Subpart D of today's proposal, as a method of freeing-up or generating the allowances that would be required to be deducted to offset the excess. (See, Section 77.2(e).) Accordingly, pursuant to an approved excess emissions offset plan, the allowances could be deducted from a compensating or substitution unit's Allowance Tracking System account.

Section 77.3(l) provides that, upon a determination of completeness, the proposed excess emissions offset plan would be binding on the designated representative and the owners and operators of the unit(s) governed by the plan, and would presumptively revise any inconsistent provisions of the permit and approved compliance plan for the affected source. The proposed offset plan would remain in effect until the Administrator acted on the proposal as provided in Section 77.3(i). This approach is proposed to be consistent with 40 CFR Part 72 and to ensure expeditious action by the source toward achieving the offsets and that, at any given time, there is

maximum possible certainty regarding what requirements apply to an affected source. However, total clarity would not be achieved until the offset plan is approved following public comment.

Following approval of an excess emissions offset plan by the Administrator, Section 77.3(l) also provides that the excess emissions offset plan would be deemed to be incorporated into the permit without further review or revision as an administrative amendment under proposed Section 72.303. It should be noted that, since approval of the excess emissions offset plan would amend the permit, the Administrator's action on the plan would be a permitting decision. Such action would, thus, be subject to the permit appeals provisions of Subpart H of 40 CFR Part 72 and Section 307 of the Act.

Subsections 77.3(m) and (n) provide that it is a violation of the Act and this part: (i) for a designated representative of an affected unit with excess emissions to fail to submit a complete and approvable proposed excess emissions offset plan or any progress reports required by 40 CFR Part 77, in a timely manner; (ii) for a unit to fail to comply with the terms of a proposed or approved excess emissions offset plan; or (iii) for anyone subject to 40 CFR Part 77 to fail to offset excess emissions as required by that part. Any such failure would be a separately enforceable violation of the Act. Additionally, Section 77.3(o) provides that each day of delay after the 60-day deadline for submitting excess emissions offset plans, or after a reporting deadline, would be deemed a separately enforceable violation of the Act. These provisions are intended to create certainty and to put the regulated community on notice of the high price that would be paid by not complying strictly with the program's requirements.

F. *Excess Emissions Penalties.*

Section 77.4 and Appendix B of today's proposal specify the requirements that would apply for the imposition, calculation, and payment of excess emissions penalties. Consistent with Section 411(a) of the Act, Section 77.4(a) would require that the designated representative of an affected unit which had excess emissions of sulfur dioxide or nitrogen oxides in any calendar year submit payment of the excess emissions penalty without demand. (The method for calculating tonnage emissions of nitrogen oxides will be specified in 40 CFR Part 76.)

Section 77.4(a) also provides that the designated representative and the owners and operators of the affected unit with excess emissions would be held strictly liable for the obligation to automatically pay, without delay, any penalty due under this part.

The proposal restates the statutory mandate in Section 411(a) that excess emissions penalties are due automatically (i.e., January 1 of the year following any excess emissions) and are subject to the Miscellaneous Receipts Act. However, the rule proposes that payments of excess emissions penalties owed would have to be paid no later than the deadline for submitting the excess emissions offset plan, (i.e., no later than 60 days after

the end of the calendar year in which excess emissions occurred at an affected unit.) Although this would extend the date for payment of the penalty, it would afford affected sources a reasonable period of time to conform their allowance accounts with end-of-year allowance purchases, as is proposed in 40 CFR Part 73.[2] (See, discussion below regarding the Section 77.3(c) interest obligation.) Thus, not later than the allowance transfer deadline, an affected unit with excess emissions (i.e., an affected unit that was not able to conform its account as of the allowance transfer deadline), would either pay the excess emissions penalty plus interest or be deemed out of compliance with the penalty payment obligation. In this regard, affected sources relying on the allowance transfer deadline would do so at their own risk. Thus, with regard to penalties for excess emissions, the allowance transfer deadline does not affect the underlying statutory obligation and provides only a conditional reprieve from the absolute statutory obligation to pay excess emissions penalties automatically. (In the event of over-payment of penalties, the over-payment will be reimbursed pursuant to U.S. Treasury procedures.)

Section 77.4(b) states that the designated representative responsible for submitting the penalty is also responsible for correctly calculating that penalty. Affected sources would, thus, be obligated to correctly calculate penalties in accordance with a proposed formula. Section 77.4(b)(2) specifies the formula to determine the excess emissions penalty. The formula specifies that in October of each year, EPA will publish the adjusted excess emissions penalty, based on the excess emissions Consumer Price Index (CPI) penalty adjustment rate (EEPAR), calculated pursuant to Appendix B of this part, and multiplied by the statutory base penalty rate of $2,000. The designated representative would be required to multiply the adjusted excess emissions base penalty by the number of tons of excess emissions (Q) to derive the excess emissions penalty (EEP): EEP = ((EEPAR x $2,000) x Q). The statutory base-penalty CPI adjustment is mandated by Section 411(c), and ensures that excess emissions penalties remain a strong disincentive to avoided or delayed compliance. In this way pollution control would remain a cheaper option than noncompliance. Consistent with the 40 CFR Part 73 CPI adjustment for allowance auctions and sales, and, as provided in Appendix B, EPA proposes to publish the Consumer Price Index (CPI) adjusted excess emissions base penalty by October 15 of each year of the program (beginning in 1995). This will help ensure against disputes. EPA seeks comment on the CPI-adjusted penalty rate formula in Appendix B.

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[2] The rule, thus, distinguishes the deadline when penalties are "due" and the deadline when "penalties due" are "payable", to integrate the automatic nature of the penalty obligation with the proposal in 40 CFR Part 73 to allow for a 30-day grace period for end-of-year allowance transactions.

The CPI can also be obtained by:
(a) Contacting the Consumer Price Index Branch at (202) 523-1121; or
(b) From the following publications:
(1) Consumer Price Index Detailed Report;
(2) Monthly Labor Review;
(c) The publications listed in Subsection (b) are available from the:

(1) Superintendent of Documents
U.S. Government Printing Office
Washington, D.C. 20402, or

(2) Bureau of Labor Statistics
Publication Sales Center
P.O. Box 2145
Chicago, Illinois 60690

Because the statute requires that excess emissions penalties are due automatically and payable without demand immediately after the end of the previous calendar year (See, Section 77.4(a)), the rule also proposes that the penalty include interest, accruing beginning on January 1 of the year following the year the excess emissions occurred until the penalty is paid. (See, Section 77.4(c).) This is consistent with other statutory authorities obligating the payment of moneys to the U.S. Treasury in accordance with the Miscellaneous Receipts Act. (See, e.g., 28 U.S.C. § 1961.) In addition, an interest requirement would encourage compliance with the automatic nature of the penalty obligation, and be a clear disincentive for delays. The interest adjustment is in addition to the annual consumer price index adjustment to the statutory base penalty required by the statute and to any other penalty liability an affected source might incur for violations of the Act.

The Agency is proposing that interest on the excess emissions penalties accrue beginning January 1 of the calendar year following the year to which the penalties apply for the following reason. Despite the proposal of a 30-day period for completion of prior year allowance transfers, the penalty is accrued for the calendar year ending December 31. If a source is able to obtain allowances in January to cover excess emissions from the prior year, then no penalty, and thus no interest will accrue. However, if the source is unable to purchase such allowances in January, the penalty for the prior year should become due January 1, and thus failure to pay such penalty on that date should result in interest being assessed from that point on. In other words, the proposed 30-day compliance transfer deadline would not change the statutory obligation to comply for the "calendar year", rather, any allowances obtained by a source before the compliance transfer deadline will be deemed to have been held by the source for the previous "calendar year". Thus a source that has excess emissions in the prior calendar year, and makes no effort to purchase allowances to

cover those emissions in January would not escape 30-days of interest accrued.

Alternatively, the interest on excess emission penalties could accrue beginning at the allowance transfer deadline. EPA solicits comment on its proposal to assess interest on excess emission penalties beginning January 1.

Section 77.4(c)(1) proposes that the interest rate be calculated based on the coupon issue yield equivalent of the 52-week U.S. Treasury bills average accepted auction price as determined by the Secretary of the Treasury, since this is a good indicator of the economic benefit a source might derive from delaying payment of the penalty.

Section 77.4(c)(2) provides the formula for determining the total penalty, with accrued interest (EEP_i). The formula specifies that the EEP_i is equal to the excess emissions penalty "(EEP)", as calculated pursuant to Section 77.4(b)(2) (discussed above), multiplied by the sum of the interest rate "(i)" , as calculated pursuant to Section 77.4(c)(1), plus one (1). Therefore, the formula to derive the total penalty with accrued interest, (EEP_i), is: $EEP_i = EEP \times (1 + i)^n$.

Section 77.4(d) would require that any penalty be due and payable automatically without demand, and specifies how penalty payments would have to be made. The rule also provides, consistent with Section 411, that penalties are required to be submitted to the Administrator payable to the "U.S. Treasury", subject to the Miscellaneous Receipts Act. Payments of penalties less than $25,000 would have to be by cashier's or certified check, made payable to the "U.S. Treasurer", and sent to the appropriate lock box for the EPA Regional Office for the State where the affected unit is located. The amount of interest on such penalties would be calculated based on the month the check is received at the lock box. The Agency is currently considering whether to require that the penalty payment be sent to a central lock box, with copies of the submission sent to the Regions. This will be clarified in the final rule, with lock box addresses to be specified in Appendix C to 40 CFR Part 77. Payments of penalties of $25,000 or more would have to be made by wire transfer to the "U.S. Treasury" at the Federal Reserve Bank of New York. This is a standard procedure which banks are familiar with for paying obligations owing to the U.S. Government. A written confirmation of payment would be required to be sent to EPA. The amount of interest on penalties of $25,000 or more would be based on the month the check is received by the U.S. Treasury. Any affected source failing to pay the penalty in this manner would do so at its own risk.

Section 77.4(e) provides that it would be a violation of the Act for the designated representative of an affected unit, liable for penalty payments under this part, to fail to correctly determine the penalty amount, or to pay the penalty, as required by this part. Section 77.4(f) provides that any such failure would be deemed a separately enforceable violation of the Act, as

would be any other failure to comply with the requirements of 40 CFR Part 77.

Section 77.4(g) restates the savings clause of Section 411(e), providing that any excess emissions penalty due under 40 CFR Part 77 would not affect the liability of the affected unit's designated representative, owners, and operators for any additional fine, penalty or assessment for the same violation authorized under any other section of the Act.

Section 77.4(h) provides that the obligation to pay such penalties is subject to the limitation in Section 411 concerning orders issued under Section 110(f) of the Act. However, only orders issued during the year in which the excess emissions occurred would be excused.

G. *Other.*

Section 77.5 specifies other relevant requirements for today's proposal, including the addresses for submissions, reservations of Federal and State authorities, signatory requirements, recordkeeping, availability of information, and computation of time. These proposed requirements are consistent with those included in Part 72 of today's proposal. The reader is referred to the Part 72 preamble of today's proposal for a discussion of these proposed requirements.

VIII. Impact Analyses

A. Executive Order 12291

Under Executive Order 12291, the Administrator must judge whether a regulation is "major" and therefore subject to the requirement to conduct a Regulatory Impact Analysis (RIA). This proposed rule package is "major" as defined in 1(b) of F.O. 12291 because the annual effect on the economy will be greater than $100 million. While the annual effect on the economy will be greater than $100 million, EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of United States enterprises to compete with foreign enterprises in domestic or foreign markets due to the proposed regulations.

Title IV, on its own without any implementing regulations, mandates extensive emission reductions and imposes continuous emission monitoring requirements on all sources. The reductions basically impose a reduction in emissions equal to the limit of allocated "basic" allowances. Such a program costs much more than the program assuming the allowance trading program, which provides for flexible, cost-effective compliance, the permits program, which provides for special compliance options such as the Phase I technology reserve program, and the monitoring program, which allows sources to implement alternative monitoring systems if they are demonstrated to match or exceed CEM systems.

A high base case and a low base case scenario were used in the analysis. These two cases were used by EPA to estimate the impacts of the legislation during the debate in Congress.

EPA's RIA evaluates the effects of a set of three regulations termed the "implementation regulations." These regulations are:

- Permit regulation;
- Allowance System regulation, including tracking, transfers, auctions and sales, and conservation and renewable energy;
- Continuous emissions monitoring regulation.

Collectively, this set of implementation regulations establishes and implements the core of the acid rain program. NO_x control costs were not included in this analysis.

EPA estimated the costs of achieving the reductions in SO_2 emissions under the statute and the implementation regulations for the time period from 1993 through 2010. While the total costs will be much lower in Phase I than Phase II, this analysis annualized the costs over the entire 18-year period. The statute without the implementation regulations (absent regulations case) imposes substantial costs, with the total annualized costs ranging from $1.6 to $2.5 billion per year. The costs of the implementation regulations (regulatory case), with total annualized costs ranging from $0.9 to $1.5 billion, are substantially less than the costs of the statute absent the implementation regulations. Thus, to achieve the mandated SO_2 emission reductions, the implementation regulations result in annual cost savings of between $0.7 and $1 billion compared to the statute absent the regulations.

While these costs are large in absolute terms, they are relatively small compared to the $200 billion average annual costs of generating electricity. The annualized costs of the implementation regulations are estimated to increase the annual costs of generating electricity by 0.5 to 1.2 percent.

For permitting under the regulatory case, program participants will incur administrative costs to obtain permits. The administrative cost for affected sources to obtain permits is estimated to be $0.5 million per year for Phase I (1995-1999) and $5.4 million per year for Phase II (2000-2010). Under the absent regulations case, no permitting would take place, so there would be no costs associated with permits.

In the regulatory case, EPA estimates that the total impact for participants in the allowance trading market will range between $15 and $30 million per year. This estimate includes market evaluation and transactions costs. These costs are based on the assumption that transactions costs will average 1.5 percent of the value of trades, which is assumed to range between $1 and $2 billion annually. In the absent regulations case, no trading would occur, so there would be no transaction costs in that case.

Although the auction and direct sale regulations are not included in this rulemaking, the costs are presented here for completeness. The total estimated annual costs to auction participants are minor, ranging from $13,600 to $81,300. The estimated total costs for direct sale applicants is $13,500 over 2 years. Assuming all IPP guarantee applications occur in the first year, the total cost to IPP guarantee applicants is estimated to be $225,000.

The conservation and renewable energy reserve is an optional program intended to provide additional incentive for utilities to conduct conservation programs. Affected sources that choose to participate in this program are likely to do so because it is economically beneficial. Under the regulatory case, the cost to affected sources that choose to participate associated with obtaining allowances from the conservation and renewable energy reserve is estimated to be $100,000 to $200,000 per year. These costs include the burden to

assemble and submit an application to EPA each year in order to receive allowances from the reserve. Under the absent regulations case, no conservation and renewable energy reserve would be established.

For monitoring, the costs to the regulated community under the absent regulations case include costs associated with the installation and maintenance of continuous emissions monitors (CEMs), continuous opacity monitors (COMs), and flow monitoring systems, if they do not already have one in place. No alternative monitoring methods would be allowed and no data reporting costs would be incurred. In this case the estimated cost to the regulated community is $173 million annually.

The analysis considered five monitoring options under the regulatory case. All five options include operation and maintenance requirements. Option 1 presents the most stringent regulatory case and has an estimated annualized cost to electric utilities of $225 million dollars. Option 2 permits the use of alternative monitoring methods and is estimated to cost $209 million annually. Option 3 exempts retiring plants from all monitoring requirements and has an estimated annualized cost of $220 million. Option 4 requires the use of standardized data reporting and recordkeeping requirements and is estimated to cost $221 million annually. Finally, EPA's proposed option, Option 5 combines all of the other regulatory options and has an estimated annualized cost of $203 million.

In both the absent regulation and regulatory cases the will yield environmental benefits due to the 10 million ton reduction in SO_2 below 1980 levels. The reductions will result in less acid rain and sulfate exposure, and better visibility and local air quality. The implementation regulations are expected to generate additional long run benefits by creating

incentives for the development of improved pollution control technology.

The analysis is contained in the Regulatory Impact Analysis (RIA) of the Proposed Acid Rain Regulations, June 1991, EPA, Office of Atmospheric and Indoor Air Programs.

This proposed rule and RIA were submitted to the Office of Management and Budget (OMB) for review prior to publication as required by E.O. 12291.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires each Federal agency to perform a Regulatory Flexibility Analysis for all rules that are likely to have a "significant impact on a substantial number of small entities."

For the purposes of this analysis, EPA used the Small Business Administration definition that a small electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year. Not all small utilities are affected by the acid rain Title of the Act. Utilities will be unaffected if all of their units are: (1) exempt (e.g., units use non-fossil sources of energy or simple gas turbines), or (2) below statutory minimums for electric generating capacity (e.g., generate less than 25 megawatts).

To examine the effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. Costs of SO_2 reductions are the incremental costs of acid rain controls, relative to the pre-statute case, under the absent regulations and regulatory cases. The implementation regulations lead to cost savings (or no change) relative to the absent regulations case for each model utility. However, even after the reductions in cost provided by the implementation regulations, the

impacts on some small coal- and oil-fired utilities are still significant. In the worst case, the regulatory cost to these utilities could represent between 6 to 7 percent of the average value of electricity produced in the year 2000. About 36, or one-third, of the 105 affected small utilities could face impacts of up to this magnitude. The other two-thirds have regulatory impacts that are comparable to or less than the impacts on all utilities as a group.

EPA's analysis concludes that virtually all of the impacts on small entities are caused by statutory provisions of the Act. Although EPA is considering regulations that are intended to mitigate some of the burden on small businesses, the statutory provisions restrict the amount of relief that can be given. The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be similar to the savings for larger utilities. Therefore, by implementing these regulations, EPA has provided all the relief available under the statute to help the most affected small utilities. Based on this analysis and pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this attached rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

C. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. An Information Collection Request document has been

prepared by EPA (ICR No. 1584) and a copy may be obtained from Sandy Farmer, Information Policy Branch; EPA; 401 M St., S.W. (PM-223Y); Washington, DC 20460 or by calling (202) 260-2740.

The total public reporting burden for these regulations is estimated to range between 66,000 and 73,000 hours in 1993; 33,000 and 40,000 hours in 1994; and 32,000 and 40,000 hours in the first five months of 1995. In order to obtain a permit, the public reporting burden to develop a permit application and compliance plan including certification of a designated representative is estimated to average a total of 370 hours per application. For tracking and transferring allowances, the public reporting burden to complete and submit an allowance tracking system new account form (if necessary) and an allowance transfer form is estimated to average 30 hours and 1 hour respectively. The burden for assembling and submitting an application to obtain allowances from the conservation and renewable energy reserve is estimated to average 80 hours per application. Finally, to meet the emissions monitoring requirements, the public reporting burden is estimated to average 40 hours per report per plant for preparing and submitting quarterly emissions data reports, and 15 hours per plant for submitting a one time monitoring plan. These burden estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding these burden estimates or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch; U.S. Environmental Protection Agency; 401 M St., S.W. (PM-223Y); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management

and Budget, 726 Jackson Place NW, Washington, DC 20503, marked "Attention: Desk Officer for EPA." The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

IX. Supporting Information

List of Subjects

Air pollution control, Electric utilities, Sulfur dioxide, Nitrogen oxides, Continuous Emissions Monitors, Permits, Compliance Plans, Reporting and recordkeeping requirements.

October 29, 1991
Date

William K. Reilly
William K. Reilly
Administrator
U.S. Environmental Protection Agency

For the reasons set forth in the preamble, Parts 72, 75, and 77 are proposed to be added and Part 73 is proposed to be amended to Chapter I of Title 40 of the CFR to read as follows:

PART 72—PERMITS REGULATION

Subpart A—Acid Rain Permit Program General Provisions

Sec.

72.1 Purpose and scope
72.2 Definitions
72.3 Measurements, abbreviations, and acronyms
72.4 Addresses for submissions
72.5 Federal authority
72.6 State authority
72.7 Applicability
72.8 Prohibitions
72.9 Signatory requirements
72.10 Recordkeeping
72.11 Availability of information
72.12 Computation of time
72.13 False certifications

Subpart B—Designated Representative - Certification Procedure

72.20 Certificate of representation
72.21 Duties of the designated representative
72.22 Changing the designated representative
72.23 Objections
72.24 Change owners and operators
72.25 Designated representative identification number

Subpart C—Acid Rain Permit Applications and Compliance Plans

72.30 Requirement to apply
72.31 Information requirements for acid rain permit applications
72.32 Acid rain compliance plan requirements
72.33 Binding effect of acid rain program permit applications and proposed compliance plans

Subpart D—Acid Rain Compliance Options

72.40 General
72.41 Phase I substitution plans
72.42 Phase I extension plans
72.43 Phase I reduced utilization plans
72.44 Phase II repowering extensions
72.45 New unit plans
72.46 Phase I or phase II nitrogen oxides emissions averaging plans

72.104 Record of appeal proceeding
72.105 Proposed findings and conclusions and supporting brief
72.106 Proposed decision

72.107 Interlocutory appeal
72.108 Appeal of proposed decisions to the administrator

Subpart I—Acid Rain Phase II Implementation

72.200 Relationship to title V operating permit program
72.201 Approval of state programs - general
72.202 State permit program approval criteria
72.203 Submission by affected sources of permit applications and compliance plans for phase II
72.204 State issuance of phase II permits
72.205 Federal issuance of phase II permits

Subpart J—Permit Revisions

72.300 General
72.301 Permit modifications
72.302 Fast-track modifications
72.303 Administrative permit amendment
72.304 Automatic permit amendment
72.305 Excess emissions offset plans
72.306 Permit reopenings

Subpart K—Compliance Certification

72.400 General
72.401 Quarterly reports
72.402 Annual reports
72.403 Other
72.404 Certification statement
72.405 Compliance option certifications
72.406 Demonstration of compliance with substantive requirements of compliance plans
72.407 Submission of documents
72.408 Excess emissions
72.409 Accounting for phase I shifts in utilization

Subpart L—Phase I Extension Early Ranking Procedures

72.500 General
72.501 Early ranking procedure

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS
APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS
APPENDIX C TO PART 72—ACID RAIN PERMIT PROGRAM FORMS

AUTHORITY: 42 U.S.C. 7651

(as provided in Title IV of the Act) except in compliance with a permit issued by a permitting authority under this title.

(3) Section 506(b) of the Act, which provides that the provisions of this title . . . shall apply to permits implementing the requirements of Title IV except as modified by that title.

(4) Section 403 of the Act, concerning the Acid Rain allowance program;

(5) Section 407 of the Act, concerning nitrogen oxides compliance options;

(6) Section 409 of the Act, concerning repowering extensions;

(7) Section 114 of the Act, which contains EPA's investigatory authorities; and

(8) Section 113 of the Act, which contains EPA's general enforcement authority.

§ 72.2 Definitions.

The terms used in this part shall have the meaning given in the Act as interpreted by this part and 40 CFR Parts 73-78, and in this section, as follows:

Acid Rain compliance option means one of the following methods of compliance used by an affected unit under this part as described in a compliance plan submitted and approved in accordance with Subpart D of this part:

(1) Standard sulfur dioxide compliance method: having total emissions in any calendar year that are not greater than the allowances held, as of the allowance transfer deadline, in the unit's compliance subaccount for that year in accordance with a plan submitted and approved under § 72.40(b);

(2) Standard nitrogen oxides compliance method: emitting nitrogen oxides from an affected unit during a calendar year in an amount not greater than allowed by the applicable emissions limitation for the unit, pursuant to 40 CFR Part 76, in accordance with a plan submitted and approved under § 72.40(b);

(3) Compliance with a substitution plan submitted and approved in accordance with § 72.41;

(4) Compliance with a Phase I Extension plan submitted and approved in accordance with § 72.42;

(5) Compliance with a reduced utilization plan submitted and approved in accordance with § 72.43;

(6) Compliance with a repowering extension plan submitted and approved in accordance with § 72.44;

(7) Compliance with a new unit plan submitted and approved in accordance with § 72.45;

(8) Compliance with a nitrogen oxides emissions averaging plan submitted and approved in accordance with § 72.46;

(9) Compliance with a nitrogen oxides alternative emissions limitation plan submitted and approved in accordance with § 72.47;

(10) Compliance with a nitrogen oxides compliance deadline extension plan submitted and approved in accordance with § 72.48;

Sections 404(a)(2), 404(g), and 416(b) of the Act and 40 CFR Part 73, Subpart B.

Allowance Tracking System means the system by which the Administrator issues, records, and tracks allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, which is the last day on which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Alternate designated representative means the natural person designated in a certificate of representation submitted by a designated representative in accordance with Subpart B, to act on behalf of the designated representative with regard to all matters within the authority of the designated representative under the Acid Rain program.

Alternative monitoring system means a system designed to provide direct or indirect determinations of mass per unit time emissions, pollutant concentrations, and/or flow data that are demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a continuous emission monitoring system.

Applicable requirement of the Act means all of the following as they apply to units in a source, unless the context of the regulation requires otherwise:

(1) Requirements of the applicable implementation plan approved or promulgated by the Administrator under Title I of the Act that implement the relevant requirements of the Act, including any revisions to that plan, in Part 52 of this chapter.

(2) Terms and conditions of any preconstruction permits issued pursuant to Title I, Parts C or D of the Act.

(3) Requirements of any standard and any other requirements promulgated under Section 111 of the Act.

(4) Requirements of any standard promulgated for hazardous air pollutants and any other requirements under Section 112 of the Act.

(5) Requirements of the Acid Rain program under Title IV of the Act and 40 CFR Parts 72-78;

(6) Any monitoring, reporting, and certification requirements established pursuant to Section 504(b) or Section 114(a)(3) of the Act.

(7) Standards and regulations governing solid waste incineration, under Section 129 of the Act.

(8) Standards and regulations for consumer and commercial products, under Section 183(e) of the Act.

(9) Standards and regulations for tank vessels, under Section 183(f) of the Act.

(10) Requirements of the program to control air pollution for Outer Continental Shelf sources, under Section 328 of the Act.

(11) Requirements of the program to protect stratospheric ozone, under Title IV of the Act.

of the Acid Rain program to the Administrator or permitting authority, as appropriate, and that is signed and verified by the designated representative in accordance with Subparts B and K of this part and 40 CFR Parts 73-78.

Compliance plan, for purposes of the Acid Rain program, means the permit document submitted in accordance with Subparts C and D of this part, using the standard forms specified in Appendix C of this part, certifying that the source will comply with all applicable requirements under the Acid Rain program, specifying the Acid Rain compliance option(s) by which each affected unit at the source will meet the applicable emissions limitation requirements of Title IV of the Act, and stating, where applicable, a schedule and description of the method or methods of compliance.

Compliance subaccount means an affected unit's Allowance Tracking System subaccount in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances for the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances for the preceding calendar year.

Construction means fabrication, erection, or installation of a unit or any portion of a unit.

Continuous emissions monitoring system means the equipment required by 40 CFR Part 75 used to sample, analyze, measure, and provide, on a continuous basis, a permanent record of emissions and flow expressed in pounds per hour (lb/hr) for sulfur dioxide, in dry standard cubic feet per hour (dscfh) for volumetric flow, and in pounds per million Btu (lb/mmBtu) of heat input or pounds per hour (lb/hr), where appropriate, for nitrogen oxides. The following systems are component parts included in a continuous monitoring system: (1) sulfur dioxide pollutant concentration monitor, (2) flow monitor, (3) nitrogen oxides pollutant concentration monitor, (4) diluent gas monitor (oxygen or carbon dioxide), and (5) a data acquisition and handling system. A continuous moisture monitor may also be included.

Control unit means a unit employing a qualifying Phase I technology in accordance with a Phase I Extension plan under § 72.42. A control unit may be a Phase I unit, or a Phase II unit that has been designated as an affected unit during Phase I pursuant to a substitution plan under § 72.41 or a reduced utilization plan under § 72.43.

Decisional body, as applied to permit appeals under Subpart H of this part, means any EPA employee who is or may reasonably be expected to act in a decision making role in a proceeding under Subpart H, including the Administrator, the Chief Judicial Officer, and a Presiding Officer when not designated as a member of the EPA trial staff, and any staff of any such persons participating in the decisional process.

Demand-side measure means a measure to improve the efficiency of consumption of electricity by customers of an electric utility

Energy conservation measure means a supply-side or demand-side measure (including those that became operational before January 1, 1992).

EPA means the United States Environmental Protection Agency or, for purposes of 40 CFR Part 73, any person who by delegation or contract is managing and conducting the auctions and direct sales provided in 40 CFR Part 73 on behalf of EPA.

EPA Conservation Verification Protocol means a methodology developed by the Administrator to be used in calculating the electricity saved from energy conservation measures and improved unit efficiency measures for the purposes of Title IV of the Act.

EPA trial staff means an employee of EPA, whether temporary or permanent, who has been designated by the Administrator under Subpart H to investigate, litigate, and present evidence, arguments, and positions of EPA in any evidentiary hearing under this part. Any EPA or permitting authority employee, consultant, or contractor who is called as a witness in the evidentiary hearing by EPA trial staff shall be deemed to be EPA trial staff.

Ex parte communication means any communication, written or oral, relating to the merits of an adjudicatory proceeding under Subpart H, that was not originally included or stated in the administrative record, in a pleading, or in an evidentiary hearing or oral argument under Subpart H, between the decisional body and any interested person outside EPA or any EPA trial staff. Ex parte communication shall not include:

(1) Communication between EPA employees other than between an EPA trial staff and a member of the decisional body;

(2) Communication between the decisional body and interested persons outside the Agency, or any EPA trial staff, where all parties to the proceeding have received prior written notice of the proposed communication and are given an opportunity to be present and to participate therein.

Excess emissions means:

(1) Any tonnage emissions of sulfur dioxide by an affected unit during a calendar year that exceeds the sulfur dioxide allowances held as of the allowance transfer deadline in the unit's compliance subaccount; and

(2) Any tonnage emissions of nitrogen oxide by an affected unit during a calendar year that exceed the annual tonnage equivalent of the emissions limitation applicable to the affected unit as specified in 40 CFR Part 76 and the affected unit's permit.

Existing affected unit, for purposes of Part 73, means a unit that is both an affected unit and an existing unit, as defined in this part.

Existing unit means a unit (including a unit subject to Section 111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990 and that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an existing unit. Existing unit does not include simple combustion turbines, or units that serve only generators with a nameplate capacity of 25MWe or less.

Non-utility unit means a unit other than a utility unit.

Offset plan means a plan submitted and approved pursuant to 40 CFR Part 77 for offsetting excess emissions that have occurred at an affected unit in any calendar year.

Oil-fired means the combustion of fuel oil for more than 10-percent of the annual heat input and of natural gas for the remaining annual heat input.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Opt-in unit shall have the meaning specified in 40 CFR Part 74.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in Section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or operator means any person who is an owner or who operates, controls, or supervises in any way an affected unit or affected source of which an affected unit is a part, and shall include but not be limited to any holding company, operating company, utility system, designated representative, or plant manager of an affected unit or affected source.

Permit modification means a revision of an Acid Rain permit pursuant to § 72.301.

Permit revision means a permit modification, automatic permit amendment, administrative permit amendment, or fast track modification.

Permitting authority means either of the following:

(1) The Administrator in the case of EPA implementation of the Acid Rain permit program; or

(2) The State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under Title IV and V of the Act and 40 CFR Part 70 and Part 72, Subpart I.

Permitting decision means any action taken by the Administrator under this part following, where provided for in this part, an opportunity for public comment. Permitting decision includes only permitting actions which, in the absence of an administrative appeal file pursuant to Subpart H of this part within 60 days of the action, would become final agency action within the meaning of Section 307 of the Act. Permitting decision does not include any interim decision, including proposed permits, draft permits, and determinations of completeness. Permitting decision also does not include any action by the Administrator pursuant to 40 CFR Parts 73-76.

performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990; or

(2) Any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Ranking application means an application submitted to the Administrator pursuant to § 72.42 of this part.

Recordation means the official deposit or withdrawal of allowances, by the Administrator, in or from an account or subaccount in the allowance tracking system.

Reduced utilization means a reduction, during any calendar year during Phase I, in the annual average heat input at an affected unit, below the unit's baseline where such reduction subjects the unit to the requirements of § 72.43.

Reduced utilization through energy conservation means reduced utilization at an affected unit demonstrated to have resulted from an energy conservation measure approved by the Administrator in accordance with § 72.43.

Reduced utilization through improved unit efficiency means reduced utilization at an affected unit demonstrated to have resulted from measures involving the modification or installation of technology, or the improvement of operating procedures at an affected unit, that increases the amount of electric generation per Btu of heat input and is approved by the Administrator in accordance with § 72.43.

Renewable energy generation means electrical energy derived from biomass, solar, geothermal, wind generation, or other resource as determined by the Administrator in consultation with the Secretary of Energy in accordance with 40 CFR Part 73, Subpart F and Appendix 1(c) of that subpart and includes such generation by installations that became operational before January 1, 1992.

Renewal means the process by which a permit is reissued at the end of its term.

Repowering extension period means the period beginning January 1, 2000, until the affected unit for which the extension has been granted, is removed from operation to install the repowering technology or to be permanently replaced, but not later than December 31, 1993.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Act, including any applicable Acid Rain permit requirement.

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Simple combustion turbine means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing but excludes such units with auxiliary firing.

selected in such solicitation if the utility has named the IPPF as one of the projects with which it intends to negotiate a power sales agreement.

Utility power distribution system means the portion of an electric system owned or operated by a utility that is dedicated to delivering electric energy to end-users.

Utility system or system means a unit or units controlled by the same utility operating company as reported on the Acid Rain data system.

Utility unit means a unit owned or operated by a utility:

(1) That serves a generator that produces electricity for sale, or

(2) That during 1985, served a generator that produced electricity for sale.

(3) Notwithstanding paragraphs (a) and (b) above, a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale, shall not be a utility unit for purposes of the Acid Rain program.

(4) Notwithstanding paragraphs (a) and (b) above, a unit that cogenerates steam and electricity is not a utility unit for purposes of the Acid Rain program , unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990 and supplies, more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale.

Utilization means the heat input for a unit.

§ 72.3 Measurements, abbreviations, and acronyms.

The abbreviations, symbols, and measurements used in this part are defined as follows:

Btu - British thermal unit
mmBtu - million Btu
hr - hour
Kwh - kilowatt hour
lbs - pounds
MWe - megawatt electrical
dscfh - dry standard cubic feet per hour
NERC - North American Electric Reliability Council
DOE - Department of Energy
EPA - Environmental Protection Agency
EIA - Energy Information Administration

§ 72.4 Addresses for submissions.

(a) All submissions required by this part that must be submitted to EPA Headquarters, shall be addressed to the Chief, Permits and Technologies Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of California, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 614 H Street, N.W., Washington D.C. 20001.

State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.

State of Iowa, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of Maryland, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th floor, Lansing, Michigan 48926.

Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.

State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.

State of Washington, Department of Ecology, Olympia, Washington 98504.

State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

As appropriate, the State air pollution control agency shall forward any permit application to the approved permitting authority if other than the State air pollution control agency for processing.

(d) For all submissions required by this part to be submitted to a State, an EPA Regional office, or EPA Headquarters, copies shall also be sent to the State permitting authority or air pollution control agency, to the appropriate EPA Regional office, and to EPA Headquarters. In addition, pursuant to Section 408(g) of the Act, informational copies of all submissions shall be sent to the State electric utility rate regulatory authority in the case of regulated utility units.

§ 72.5 Federal authority.

Under authority of Sections 114 and 301 of the Act, the Administrator reserves the right to:

(a) Secure information needed for the purpose of developing or implementing any standard, requirement, or prohibition under the Act or under 40 CFR Parts 70-78, or of determining whether any person is in violation of any standard, requirement, or prohibition of the Act, this part, or 40 CFR Parts 73-78;

(b) Make inspections, conduct tests, examine records, and require the designated representative, the owner, or the operator of an affected unit to submit information reasonably required for the purpose of developing or implementing any standard, requirement, or prohibition under this part and 40 CFR Parts 73-78; and

(c) Call witnesses and compel the production of documents.

(3) Any boiler that does not serve a generator;
(4) A unit that cogenerates steam and electricity, unless the unit is constructed for the purpose of serving a generator that supplies, or commences construction after November 15, 1990 and serves a generator that supplies, more than one-third of its potential electric output capacity and more than 25MWe electric output to any utility power distribution system for sale;
(5) A certified qualifying small power production source or certified qualifying cogeneration source (as defined in Section 405(g)(6)(A) of the Act and as determined in accordance with 40 CFR Part 73) that meets the criteria of paragraph (6)(i), below; or
(6) A new independent power production source if:
(i) As of November 15, 1990:
(A) A power sales agreement has been executed that is applicable to the source; or
(B) The source is the subject of a State regulatory authority order requiring an electric utility to:
(1) Enter into a power sales agreement with purchase capacity from the source, or
(2) (For purposes of establishing terms and conditions of the electric utility's purchase of power) enter into arbitration concerning the source; or
(C) An electric utility has issued a letter of intent or similar instrument committing to purchase power from the source at a previously offered or lower price and a power sales agreement is executed within a reasonable period of time; or
(D) The source has been selected as a winning bidder in a utility competitive bid solicitation; and
(ii) It is used for the generation of electricity, eighty percent or more of which is sold at wholesale; and
(iii) It is nonrecourse project financed (as such term is defined by the Secretary of Energy) within 3 months of the date of enactment of the Act (November 15, 1990); and
(iv) It is a new unit that would otherwise be required to hold allowances under the Acid Rain program.
(c) Except as otherwise provided, non-utility units are not subject to Acid Rain permitting under this part, unless they elect to become an affected unit pursuant to 40 CFR Part 74.
(d) As provided in 40 CFR 70.3(b), affected sources and affected units may not be exempted from the permitting requirements of the Acid Rain program.
(e)(1) Whenever any requirement or prohibition in this part or in 40 CFR Parts 73-78 applies to an affected source, or to the owner(s), operator(s), or the designated representative of an affected source, the requirement or prohibition shall apply to and be fully enforceable against each owner and operator of the affected source and of each affected unit at the source (including any new owner notwithstanding any change of ownership), each of whom shall (notwithstanding any private indemnification agreements between and among the designated representatives, the owners, and the operators) be liable, as a

part, 40 CFR Parts 70, 71, and 40 CFR Parts 73 through 78, including the submissions specified in § 72.21, shall be made in writing or by an authorized electronic transmission by the designated representative for the source's owners and operators and, when submitted in writing, shall be submitted by certified mail. Certified mail shall include U.S. Postal Service certified mail, or mail delivery certified by any other independent third-party postal carrier. In each submission, the designated representative shall sign and certify:

(1) That the procedure specified in the representation agreement, pursuant to § 72.20, for obtaining the authorization of the owners and operators of the affected source or unit, as applicable, to take such action has been complied with; and

(2) The following statement: I certify under penalty of law that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

(b) The permitting authority shall only act upon submissions that have been signed, certified, and filed by the duly authorized designated representative for the affected units at the source.

§ 72.10 Recordkeeping.

All notices, records, and reports (including compliance certifications), required to be maintained, issued to any person, or submitted to the Administrator, a State air pollution control agency, or a permitting authority pursuant to this part, shall be kept on file at the source for a period of 5 years. This period may be extended for cause at any time prior to the end of 5 years in writing by the Administrator or the permitting authority.

§ 72.11 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by 40 CFR Part 2.

§ 72.12 Computation of time.

(a) Any time period scheduled to begin on the occurrence of a date, number of days, act, or event shall begin on the day the act or event occurs.

(b) Any time period scheduled to begin before the occurrence of a date, number of days, act, or event shall be computed so that the period ends on the day before the act or event occurs.

to each owner's legal, equitable, leasehold, or contractual reservation or entitlement in accordance with Section 408(i) of the Act; or

(B) If such multiple owners have expressly provided for a different distribution by an agreement binding on each and every owner of the unit, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the agreement;

(ii) Except as otherwise provided in this subsection, where all legal or equitable title to or interest in an affected unit is held by a single person, the certificate of representation shall certify that all allowances in the unit's Allowance Tracking System account are deemed to be held for that person.

(iii) Notwithstanding paragraphs (i) and (ii) or any private agreements between multiple owners, each owner of an affected unit with multiple owners shall, as a matter of Federal law, be liable for the unit's compliance with the requirements and prohibitions of the Acid Rain program and for any violation of any such requirement or prohibition.

(7) A statement that the designated representative will abide by the fiduciary responsibilities imposed pursuant to this subpart and the agreement specified in paragraph (b)(1).

(8) A statement that the owners and operators of an affected source, or an affected unit at a source, shall be bound by any order issued to the designated representative by the Administrator or a court regarding the unit or source.

(c) *Alternate Designated Representative.* (1) The certificate of representation may designate an alternate designated representative to act on behalf of the designated representative, owners, and operators of the source and each affected unit at the source, in the event the certifying designated representative is absent or otherwise not available to perform actions and duties specified in this part. The alternate designated representative shall be a natural person and shall be authorized if the following conditions are met:

(i) The certificate of representation submitted by the designated representative under this section identifies the full name, address, telephone number, and facsimile number (if any) of the alternate designated representative; certifies that the alternate was selected in accordance with the agreements, conditions, and procedures specified in subsection (b); and certifies that the agreement of representation specified in subsection (b) includes a procedure for the owners, operators, and designated representative of the source and the affected units to authorize the alternate to act in lieu of the designated representative;

(ii) The alternate designated representative signs the certificate of representation, indicating that he or she is aware of his or her duties and responsibilities as alternate designated representative; and

(iii) The designated representative certifies in the certificate of representation that the designated representative,

affected source represented, and of each affected unit at the source, in all matters pertaining to the Acid Rain program, including but not limited to: the holding, transfer, or disposition of allowances allocated to the unit in accordance with 40 CFR Part 73; the submission of or compliance with permits, permit applications, permit revisions, permit renewals, compliance plans, and compliance certifications under this part; and the submission of or compliance with excess emissions penalties and offset plans in accordance with 40 CFR Part 77. Notwithstanding the preceding sentence and provisions elsewhere in this part, and consistent with § 72.7(e):

(1) Whenever a requirement or prohibition of the Acid Rain program applies to an affected source it shall be deemed to apply to the designated representative and each and every owner and operator of an affected unit at the source;

(2) Whenever a requirement or prohibition of the Acid Rain program applies to an affected unit it shall be deemed to apply to the designated representative and each and every owner and operator of an affected unit only. Except as provided in this part with regard to multi-unit compliance plans, the owners and operators of a unit at a source shall not be liable for any violation by any other affected unit located at the same source of any such affected unit requirement or prohibition.

(b) The designated representative shall sign, certify, and file all submissions under the Acid Rain program, including, but not limited to:

(1) Acid Rain permit applications, permit renewal applications, proposed compliance plans, and proposed permit or compliance plan revisions in accordance with §§ 72.41 through 72.48 and Subpart C;

(2) Submissions required to be made pursuant to any Acid Rain compliance option selected for one or more units at the affected source pursuant to Subpart D;

(3) Submissions concerning the holding, transfer, or disposition of allowances to or from a unit account, pursuant to 40 CFR Part 73;

(4) Submissions of the compliance certifications required pursuant to Subpart K, including:

(i) All emissions monitoring reports required pursuant to 40 CFR Part 75; and

(ii) All Acid Rain operation and maintenance reports required by an Acid Rain compliance option under Subpart D;

(5) Payments of any excess emissions penalties required pursuant to 40 CFR Part 77; and

(6) Submissions of any excess emissions offset plans required pursuant to 40 CFR Part 77.

(c) In each periodic (annual, quarterly, monthly, and other) compliance certification required by Subpart K of this part and 40 CFR Parts 73-78, the designated representative shall include:

(1) A statement in the annual certification required by § 72.402 that all allowance transactions, and all proceeds from

the Administrator shall rely on the certificate of representation unless and until a superseding certificate is filed with the Administrator pursuant to § 72.22.

(b) Other than as a result of a certificate of representation submitted pursuant to § 72.22 for the purpose of changing the designated representative, no objection or other communication submitted to the Administrator or the permitting authority concerning the representation of the designated representative shall affect any recordation of an allowance transfer properly submitted pursuant to 40 CFR Part 73, or the processing of any permit program submissions properly made pursuant to this part, or any other submission made by the designated representative pursuant to the Acid Rain program. With respect to any objection concerning the representation of the designated representative, in no event shall the Administrator stay any future allowance transfers or permit submissions.

(c) Neither the United States, the Administrator, the EPA, any EPA employee, nor any permitting authority will adjudicate any private legal dispute concerning the representation of any designated representative, including private disputes concerning the proceeds of allowance transfers.

(d) No objection or new certificate of representation filed by the owners or operators shall affect the finality of any permit action resulting from a submission pursuant to this part, by a designated representative duly certified pursuant to this subpart.

§ 72.24 Change owners and operators.

(a) In the event a new owner or operator of an affected unit is not included in the list of owners and operators submitted in the certificate of representation pursuant to § 72.20, such new owner or operator shall be deemed to be subject to the certificate of representation, to any permit application, permit, compliance plan, or offset plan submitted or approved under this part, and to the actions of the designated representative of the unit by operation of law.

(b) Within 30 days following the transaction giving rise to any change in ownership or operator including the addition of a new owner or operator, the designated representative shall submit a revision to the certificate of representation amending the list of owners and operators to include the change.

(c) Any new owner or operator of an affected source or of an affected unit at the source shall be subject to and be bound by, the provisions of any Acid Rain program submission made by the designated representative for the source and the Acid Rain permit and compliance plan or offset issued to the source by a permitting authority in accordance with this part.

(d) Notwithstanding the previous subsection, any change in ownership or interest in an affected unit shall require the submission of a new certificate of representation for the designated representative.

§ 72.7(a)(2), pursuant to any such option, shall be the deadline specified in the relevant section of Subpart D.

(c) *Duty to Reapply.* Except as provided above for initial Phase I and Phase II permitting, a complete Acid Rain permit renewal application shall be submitted for each source with an affected unit at least 18 months prior to the expiration of the unit's existing permit.

(d) Unless provided elsewhere in this part, copies of all permit applications and proposed compliance plans provided for in this part shall be submitted to the State permitting authority or air quality agency for the State where the source is located, to the U.S. Environmental Protection Agency Regional Office for the Region where the affected source is located, and to the U.S. Environmental Protection Agency Acid Rain Division Headquarters office, as provided in § 72.4(d).

§ 72.31 Information requirements for acid rain permit applications.

All Acid Rain permit applications shall contain the following information, which shall be submitted on the appropriate Acid Rain permit application forms as provided in Appendix C of this part:

(a) *Affected Source Information.* For the affected source for which the application is submitted, specify using SF# 7231 in Appendix C of this part:

(1) The source name;

(2) The source mailing address;

(3) The source location;

(4) The affected units and other units at the source;

(5) During Phase I, the NERC region or sub-region where the source is located, and the name of the utility system for the source.

(6) During Phase I, the aggregate baseline of all Phase I units in the system of which the source is a part;

(7) That 5 year projected utilization generation, and schedule of planned outages for each unit at the source are on record at the source.

(8) Designated representative information as follows:

(i) The name, mailing address, telephone number, facsimile number, and Acid Rain identification number for the designated representative (and alternate designated representative); and

(ii) The current certificate of representation pursuant to Subpart B.

(9) The standard provisions and prohibitions set forth in § 72.54.

(b) *Affected Unit Information.* For each affected unit at the source for which the Acid Rain permit application is submitted, specify using SF# 7231A in Appendix C of this part:

(1) The name and Acid Rain unit identification number, as provided in Appendix A or B of this part, or as reported on the NADB, of the unit;

governed by the plan, and is cross-referenced and incorporated as approved by the permitting authority without modification into the respective Acid Rain permit applications and permits for the affected sources. The designated representative for a source with an affected unit governed by a multi-unit compliance plan involving units located at one or more other source, shall include in the permit application for the source informational copies of the complete permit(s) or permit application(s) for the other source(s), including the compliance plans for each affected unit at the other source(s) governed by the multi-unit plan.

(ii) Notwithstanding paragraph (2)(i), above, no substitution plan or nitrogen oxides averaging plan shall be approved unless all units subject to such plan have the same designated representative.

(iii) The owners, operators, and designated representative of an affected unit governed by a multi-unit compliance plan shall be liable for any violation of the plan's requirements or prohibitions at any affected unit governed by the multi-unit plan, including violations at a unit governed by the plan that is located at another source.

(3) In no event shall an affected unit, including a unit which is subject to more than one compliance option, shall have more than one designated representative.

(4) Nothing in this section regarding compliance plans or in Title V of the Act shall be construed as affecting allowances, except as authorized by this part.

(b) Each affected unit shall employ one or more of the compliance options specified in paragraphs (1)-(8) below, as provided further in Subpart D, to meet its Acid Rain program emissions limitation requirements. The designated representative for each such affected unit shall submit a plan, using the appropriate standard forms specified in Appendix C of this part, selecting any such option(s) as follows:

(1) For the standard compliance method for sulfur dioxide or nitrogen oxides, the requirements set forth in § 72.40(b);

(2) For substitution plans, the requirements set forth in § 72.41;

(3) For Phase I Extension plans, the requirements set forth in § 72.42;

(4) For reduced utilization plans, the requirements set forth in § 72.43;

(5) For repowering extension plans, the requirements set forth in § 72.44;

(6) For nitrogen oxides emissions averaging plans, the requirements set forth in § 72.46 and 40 CFR Part 76;

(7) For nitrogen oxides alternative emissions limitation plans, the requirements set forth in § 72.47 and 40 CFR Part 76; and

(8) For nitrogen oxides Phase I Extension plans, the requirements set forth in § 72.48 and 40 CFR Part 76.

(c) The designated representative for an opt-in unit shall comply with the requirements set forth in § 72.49 and 40 CFR Part

Subpart D—Acid Rain Compliance Options

§ 72.40 General.

(a) *Applicability.* (1) This subpart shall apply to each affected source required to submit an Acid Rain permit application and proposed compliance plan pursuant to this part, and to each affected unit at an affected source.

(2) Each proposed compliance plan submitted pursuant to § 72.32 shall specify one or more of the Acid Rain compliance options specified in this subpart (§ 72.40(b) - § 72.50), for each affected unit at the source by including the appropriate standard form provided in Appendix C of this part and by submitting such other information required by this subpart for the option selected.

(b) *Standard Compliance.* (1) The requirement in Section 408 of the Act and under Subpart C of this part to have a compliance plan shall be deemed satisfied by a certification by the designated representative of an affected unit that the unit will meet the applicable emissions limitation requirements as set forth in the permit application and the proposed compliance plan in a timely manner.

(2) If the designated representative of any affected unit is selecting the standard compliance option only, the designated representative shall so indicate by checking the appropriate box on the Acid Rain permit application form, SF# 7231A in Appendix C of this part.

(c) In the case of sulfur dioxide, regardless of the compliance option chosen, the plan shall certify that the designated representative will hold allowances or properly submit allowances for recordation as of the allowance transfer deadline, in the Allowance Tracking System compliance subaccount for the unit, established pursuant to 40 CFR Part 73, not less than the total annual emissions of sulfur dioxide from the unit.

(d) In addition to the standard compliance option, the designated representative may select one or more of the compliance options specified in § 72.48 for the affected unit by following the procedures specified in those sections.

§ 72.41 Phase I substitution plans.

(a) *Applicability.* This section shall apply during Phase I only to existing units listed in Appendix A or B of this part, and to the designated representative, the owners, and operators of any such units seeking to designate the Appendix B unit as a substitution unit, for the purposes of meeting the Appendix A unit's Phase I sulfur dioxide emissions reduction obligations by the distribution of allowances between the two units, where the Appendix B unit is under the control of the same designated representative as the Appendix A unit for which the proposed substitution plan is submitted.

(i) Identification of each unit proposed to be governed by the substitution plan, including each Appendix A unit, and each proposed substitution unit;

(ii) The proposed date the substitution plan, if approved, would become effective (if other than January 1, 1995); or

(iii) The proposed date, if known, the substitution plan, if approved, would terminate (if prior to December 31, 1999);

(iv) Documentation, to the satisfaction of the Administrator, that the annual tonnage limits proposed in the substitution plan will, in total, achieve the same or greater annual emissions reduction than would have been achieved by the Appendix A unit and the substitution unit or units without such substitution. Such documentation shall include the following calculations, using SF# 7241 in Appendix C of this part:

(A) Calculation of the required annual emissions reductions (in tons per year) without a substitution plan for each Appendix A unit governed by the proposed substitution plan as follows:

(1) Baseline x the lesser of actual or allowable 1985 emissions rate for sulfur dioxide/ 2000 = Tons sulfur dioxide 1985

(2) Tons sulfur dioxide 1985 - Appendix A unit's basic allocation = Phase I unit's required annual emissions reduction (in tons per year) without plan

(B) Calculation of the required annual emissions reductions (in tons per year) without a substitution plan for each Appendix B substitution unit governed by the proposed substitution plan as follows:

[Baseline x lesser of actual or allowable 1985 emissions rate/ 2000] - [Baseline x the most stringent Federally enforceable allowable emissions rate in the year that the application is submitted[1] = the substitution unit's annual required emissions reductions (in tons per year) without the plan.

(C) Calculation of the proposed annual sulfur dioxide emissions reductions (in tons per year) that will be achieved by each Appendix A unit under the proposed substitution plan as follows:

Tons sulfur dioxide 1985 (as calculated in subsection (d)(1)(iv)(A)*(1)* of this section - annual projected sulfur dioxide emissions (in tons per year) under the proposed plan = annual reductions (in tons per year) that will be achieved by the Appendix A unit.

(D) Calculation of the proposed annual sulfur dioxide emissions reductions (in tons per year) required to be achieved by each

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[1] If the most stringent Federally enforceable allowable emissions rate for the substitution unit in the year that the application is submitted is the same as or less stringent than the lesser of the actual or allowable 1985 emissions rate for that unit, the reductions required of the substitute unit without the plan are deemed to be zero.

unit governed by the substitution plan shall comply with all monitoring, recordkeeping, and reporting requirements as specified in 40 CFR Part 75 and in the unit's monitoring plan.

(3) *Recordkeeping Requirements.* Each substitution plan shall require that each unit governed by the plan shall comply with the standard recordkeeping requirements specified in this part and 40 CFR Parts 73-78.

(4) *Compliance Certification Reporting Requirements.* Each substitution plan shall require that the designated representative for each unit governed by the plan shall comply with the standard compliance certification reporting requirements specified in Subpart K of this part.

(e) *Administrator's Action on Proposed Substitution Plan.*

(1) The Administrator shall act on a proposed substitution plan in accordance with the procedures and deadlines specified in Subpart G, and shall approve such plan if it fulfills the requirements of this section.

(2) The Administrator may approve a proposed substitution plan, in whole or in part, and with such modifications or conditions as may be consistent with the orderly functioning of the allowance system, if the proposal as modified or conditioned will ensure the emissions reductions contemplated by Title IV of the Act and this part.

(3) If a substitution plan meets the requirements of this section and is approved by the Administrator:

(i) Each substitution unit governed by the plan shall be a Phase I affected unit under the Acid Rain program, from the date on which the substitution plan takes effect until the date on which the plan terminates. Each source with any such unit shall be an affected source.

(ii) Each affected unit under a substitution plan shall be subject to the following requirements:

(A) The emissions monitoring planning, certification, recordkeeping and reporting requirements of this section and 40 CFR Part 75;

(B) The nitrogen oxides requirements of 40 CFR Part 76, (including that for any such unit that is *(1)* a tangentially fired boiler, or *(2)* a dry-bottom wall-fired boiler (other than units applying cell burner technology), the exemption in 40 CFR Part 76 from any more stringent Phase II nitrogen oxides emissions limitations than those required to be met in Phase I, if such more stringent limits are set by the Administrator by January 1, 1997, shall apply);

(C) The sulfur dioxide allowance allocation and emission limitation requirements specified in the plan provided in subsection (d) as approved; and

(D) The utilization requirements specified in § 72.43 (reduced utilization plans), and in § 72.409.

(iii) The Administrator shall issue permits to each affected source with an Appendix A or substitution unit, in accordance with the approved substitution plan and the requirements of this part.

representative, owners, and operators of any such unit, seeking a 2-year extension of the deadline for meeting the Acid Rain program Phase I sulfur dioxide emissions reduction requirements, pursuant to Section 404(d) of the Act, including extension allowance allocations under that authority.

(2) This section shall apply to any affected unit listed in Appendix A of this part identified in a plan submitted pursuant to this section for which a Phase I extension is sought, and to any unit listed in Appendices A or B designated in a plan submitted under this section as a control unit.

(b)(1) The designated representative for any Appendix A affected unit, as provided in subsection (a) of this section, may submit a proposed plan to the Administrator in accordance with this section for a 2-year extension of the Appendix A unit's January 1, 1995 deadline for meeting the sulfur dioxide requirements, *provided* that, notwithstanding any such extension:

(i) The designated representative shall hold allowances in each of the 2 years of the extension period, in the Allowance Tracking System compliance subaccount for each unit governed by the extension plan, in an amount not less than the unit's emissions for the year; and

(ii) The proposed plan certifies:

(A) That the Appendix A unit for which the extension is sought will install on or after November 15, 1990 but not later than December 31, 1996, a qualifying Phase I technology; or

(B) That the Appendix A unit for which the extension is sought will transfer its Phase I emissions reduction requirements, in accordance with paragraph (2) of this section, to a control unit designated in the proposed extension plan that will install and operate a qualifying Phase I technology on or after November 15, 1990 but not later than December 31, 1996; and

(C) The proposed plan meets the requirements of subsection (e) of this section.

(2) *Transfer Plans.* In the case of a compliance plan that proposes a transfer of an Appendix A affected unit's emissions reduction obligations to a control unit, the compliance plan shall govern operations at each unit included in the transfer plan, and shall specify the emissions reduction requirements imposed on each transfer and control unit pursuant to this section.

(3) If the transfer and control units designated in a proposed Phase I Extension plan are not located at the same source, the designated representative of each source shall sign and certify the proposed plan and shall include the proposed plan with the permit application for each source.

(4) The designated representative may propose to transfer the emissions reduction requirements of a single Appendix A affected unit or of multiple Appendix A affected units, in whole or in part to one or more control unit; *provided* that all control units governed by a plan are located at a single source; and *provided* further that the control unit or units shall not be committed to achieve the emissions reduction requirements of one or more

[(Projected utilization (in mmBtu) as reported on EIA Form 767 filed in the year in which the Phase I Extension application is made) x projected emissions rate (in lbs/mmBtu) not to exceed the most stringent Federally enforceable allowable emissions rate for sulfur dioxide at the time of application] ÷ 2000

(vi) Projected emissions in tons per year for each transfer unit in the plan for 1995 through 1999, calculated as follows:

[(Projected utilization (in mmBtu) as reported on EIA Form 767 filed in the year in which the Phase I Extension application is made) x projected emissions rate (in lbs/mmBtu) not to exceed the most stringent Federally enforceable allowable emissions rate at the time of application] ÷ 2000

(vii) Documentation that the annual emissions reduction obligations transferred to each control unit governed by the Phase I extension plan do not exceed those authorized under the requirements of this section, as follows:

(A) For each control unit, the basic allowance allocation (or allocation authorized under § 72.41 in the event the control unit is a substitution unit) minus the annual emissions in tons per year that would occur at the unit at 90% control using a qualifying Phase I Extension technology, equals the total annual emissions reduction obligation that a control unit may assume for transfer units authorized to be accounted for by the control unit.

(B) For each transfer unit governed by a Phase I Extension plan, the designated representative shall specify the tons per year of sulfur dioxide emissions for 1995 and 1996 from that unit for which it will receive allowances from the Phase I Extension reserve above its basic allocation not to exceed the tonnage amount that will be accounted for by each control unit in the plan. The sum total of the annual tons above basic allocations specified for all the transfer units under the plan pursuant to this paragraph shall not exceed the total annual emissions reduction obligation assumed by all the control units in the plan calculated pursuant to paragraph (A).

(C) For each transfer unit specify the total tons of emissions reduction obligations that will be accounted for by each control unit's annual emissions reductions below its basic allowance allocation.

(viii) For each unit in the Phase I Extension plan, the proposed number of allowances from the Phase I Extension reserve to be allocated for each year and the sum total of Phase I Extension reserve allowances requested for all units in the plan for 1995 through 1999.

(2) *Documentation, Standards, Schedules, and Test Methods for Demonstrating Compliance.*

(i) *Technology Standard -- 90% Control Requirement.* Each proposed Phase I Extension plan shall include the following:

(A) A copy of a fully executed contract, which may be contingent only upon the Administrator approving the proposed

case, the showing of 90% control shall be in comparison to the concentration of sulfur dioxide in the emissions of a new conventional boiler using fuel with the same sulfur content.

(4) Each proposed Phase I Extension plan shall require that the owners and operators and designated representative of the unit conduct such additional tests, and report such additional test results as the Administrator determines is necessary in support of this subsection.

(ii) *Emissions Standards.* (A) Each proposed Phase I Extension plan shall include the following Acid Rain program emissions limitations and compliance deadlines:

(1) The proposed total annual allowance allocation for each unit governed by the plan;

(2) A requirement that, during the 2 year extension period and thereafter, the designated representative shall hold allowances in the Allowance Tracking System compliance subaccount for each affected unit governed by the plan as of the allowance transfer deadline, as provided for in 40 CFR Part 73, not less than the total annual sulfur dioxide emissions from the unit.

(3)(i) A requirement that each control unit shall not be subject to the nitrogen oxides emissions limitation of 40 CFR Part 76 until the unit shuts down to install the qualifying Phase I technology, and

(ii) A requirement that beginning on the date on which the control unit is removed from operation to install the qualifying Phase I technology, each control unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR Part 76;

(4) A requirement that during the extension period and thereafter, each transfer unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR Part 76; and

(5) A requirement that, as provided for in Section 404(d)(7) of the Act, after January 1, 1997 no control unit or transfer unit shall emit sulfur dioxide in excess of the annual tonnage limitation specified in the Phase I Extension plan pursuant to subsections (e)(1)(v) and (e)(1)(vi) (for 1997-1999) of this section, as approved. Even if the designated representative holds allowances in the unit's Allowance Tracking System compliance subaccount to cover such unit's emissions for the year for purposes of 40 CFR Part 77, the Administrator shall deduct allowances equal to such exceedances of the extension plan limitation from the unit's annual allowance allocation in the following calendar year.

(B) *Emissions Limitation Test Methods and Emissions Monitoring.* Each Phase I Extension plan shall include an emissions monitoring plan as required by 40 CFR Part 75, for each unit governed by the plan, and a certification that continuous emissions monitoring systems are, or will be not later than November 15, 1993, operational and certified by the Administrator on each Phase I extension control or transfer unit, as required for Phase I units by 40 CFR Part 75.

submitted under Subpart L or a proposed Phase I Extension plan submitted under this section shall receive its basic allowance allocations during Phase I. Each Appendix B unit covered by a ranking application or proposed Phase I Extension plan shall be eligible for basic allowance allocations during Phase I, as determined by the substitution plan provisions of Section 404(b) and (c) of the Act and § 72.41 of this part. In addition to the basic allowance allocations, the Administrator shall calculate and conditionally award allowances from any allowances remaining in the Phase I Extension allowance reserve to each unit governed by an Early Ranking application submitted pursuant to Subpart L of this part, or proposed Phase I Extension plan meeting the requirements of this section, as follows:

(i) For calendar year 1995, the Administrator shall conditionally award allowances from the Phase I extension allowance reserve to each eligible Phase I extension control and transfer unit governed by the application or proposed plan, equal to the difference between:

(A) The lesser of the unit's average annual emissions in calendar years 1988 and 1989 (calculated as provided in subsection (e)(iii) of this section), or its projected emissions tonnage for calendar year 1995 (calculated as provided in subsection (e)(iv) of this section), and

(B) The product of the unit's baseline multiplied by an emissions rate of 2.50 lbs/mmBtu, divided by 2,000.

(ii) For calendar year 1996, the Administrator shall conditionally award allowances from the Phase I extension allowance reserve to each eligible Phase I extension control and transfer unit governed by the application or proposed plan, following the reductions from the reserve for such unit provided in subparagraph (i), equal to the difference between:

(A) The lesser of the unit's average annual emissions in calendar years 1988 and 1989 (calculated as provided in subsection (e)(iii) of this section), or its projected emissions tonnage for calendar year 1996 (calculated as provided in subsection (e)(iv) of this section), and

(B) The product of the unit's baseline multiplied by an emissions rate of 2.50 lbs/mmBtu, divided by 2,000.

(iii) The reserve allowances conditionally awarded to a Phase I extension control or transfer unit for use in 1995 and 1996 pursuant to subparagraphs (i) and (ii), when combined with the basic allowance allocations for each unit, shall in no instance exceed the tonnage equivalent of the most stringent Federally enforceable emissions limitation for sulfur dioxide for the unit for that year, where tonnage equivalent is calculated as follows: [(lbs/mmBtu x mmBtu for the year) ÷ 2000].

(iv) For calendar years 1997, 1998, and 1999, the Administrator shall conditionally award allowances from the reserve to each eligible Phase I extension control unit governed by the ranking application or proposed Phase I Extension plan, following the reductions from the reserve for such unit provided for in subparagraphs (i), (ii), and (iii), not to exceed the amount by

(3) No Phase I Extension plan shall be terminated following issuance of an Acid Rain permit which includes such extension. The designated representative may, however, withdraw a Phase I Extension application at any time prior to issuance of the Phase I permit and approval by EPA of the extension plan.

(4) Each proposed and approved Phase I Extension plan shall contain the prohibitions of subsection (h)(1)-(3).

§ 72.43 Phase I reduced utilization plans.

(a) *Applicability.* (1) The requirements of this section shall apply to:

(i) The designated representative, owners, and operators of any Phase I affected unit, including:

(A) Any unit in Appendix A of this part, or

(B) Any other unit that becomes an affected unit during Phase I (including any unit designated as a compensating unit pursuant to this section or as a substitution unit pursuant to § 72.41);

(ii) Where the designated representative, owners, and operators of the Phase I affected unit referred to in paragraph (i) plan to:

(A) Reduce utilization of the Phase I affected unit below the unit's baseline to achieve compliance, in whole or in part, with the unit's Phase I emissions reduction requirements, and

(B) *(1)* Shift generation of the Phase I unit to a designated compensating unit that would not otherwise be affected during Phase I, including any Appendix B or new unit; or

(2) Accomplish such reduced utilization through sulfur-free generation (including renewable energy generation), an energy conservation measure, or any improved unit efficiency measure.

(2) The requirements of this section shall not apply to the designated representative, owners, and operators of any Phase I affected unit that was utilized at a level below its baseline in any calendar year during Phase I as a result of economic dispatching, one or more forced outages, or to the extent the under-utilization was due to a system-wide downturn in sales. Nor shall the requirements of this section apply to the designated representative, owners, and operators of a Phase I affected unit that was utilized at a level below baseline in any year when the aggregate utilization of all Phase I units in the affected unit's utility system for that year was equal to or greater than the Phase I units' aggregate baseline, as reported pursuant to § 72.31(a)(6). In all such cases, however, the owners and operators of any such units shall be subject to the annual reporting requirements specified in § 72.402.

(3) The requirements of this section shall apply in the event the designated representative, owners, and operators of an affected unit decide during the course of any Phase I calendar year to rely on reduced utilization as a method of compliance. In that case, the designated representative shall submit a reduced utilization plan in accordance with this section not

(D) Documentation of the extent to which the generation decrease (in Kwh) resulting from the total reduced utilization (in Btu) at the Phase I unit will be accounted for by:

(1) Proposed kilowatt hour increases at compensating unit(s);

(2) Proposed kilowatt hour increases at sulfur-free generators;

(3) Expected kilowatt hour decreases at the Phase I unit due to improved unit efficiency at the Phase I unit; and

(4) Expected kilowatt hour decreases at the Phase I unit due to energy conservation in the unit's utility system.

(E) A certification that the reduced utilization, in combination with any other compliance option proposed to be used by the Phase I unit, will as a whole achieve compliance by the unit with its Phase I emissions reduction requirements;

(iii) The proposed date, if known, that the reduced utilization plan, if approved, would become effective (if other than January 1, 1995); or

(iv) The proposed date the reduced utilization plan, if approved, would terminate (if prior to December 31, 1999);

(v) For each compensating unit identified in the plan located at a different source (other than a sulfur-free generator), copies of the certified permit application pages, including a certificate of representation, relevant to the compensating unit;

(vi) In the case of plans relying on sulfur-free generation, energy conservation measures, or improved unit efficiency measures, a demonstration, to the Administrator's satisfaction as provided in paragraphs (2) through (4) below, that the Phase I affected unit(s) for which the plan is submitted will achieve reduced utilization through such sulfur-free generation, energy conservation, or improved unit efficiency; and

(vii) Such other information as the Administration may require.

(2) *Sulfur-Free Generation Plans.* Each proposed reduced utilization plan relying on sulfur-free generation (including generation provided by renewable energy generation) shall identify each generator that will provide such sulfur-free generation, using SF# 7243 in Appendix C of this part, and shall include the documentation specified in subparagraphs (c)(1)(ii)(C), above.

(3) *Energy Conservation Plans.* Each proposed reduced utilization plan for a Phase I affected unit that plans to achieve reduced utilization using one or more energy conservation measure shall be submitted using SF# 7243 in Appendix C of this part, and shall include:

(i) A description of each energy conservation measure that the unit's utility system will employ in the service area the unit serves, as determined in accordance with the EPA Conservation Verification Protocol provided for in 40 CFR Part 73.

(ii) A forecast of the kilowatt hour savings expected from each energy conservation measure, and the effective life of each measure as provided in the EPA Conservation Verification Protocol provided for in 40 CFR Part 73; and

(iii) A forecast of the reduced utilization that is expected to occur at the Phase I affected unit (in mmBtu) as a result of the

(in Kwh) achieved from energy conservation or improved unit efficiency through the third quarter of the calendar year (September 30) using the procedures specified in paragraph (C) below.

(2) Based on the verified energy savings, improved heat rate, and heat input reductions achieved through the third quarter, as provided in subparagraph *(1)*, the designated representative shall submit an estimate of improved heat rate (in Btu/Kwh), energy savings (in Kwh), and resulting reductions in heat input (in mmBtu) at the unit for the fourth quarter of the year (October 1 - December 31).

(B) *Fourth Quarter Confirmation Report.* Within 90 days after the end of the calendar year, the designated representative shall submit with the quarterly compliance certification report required by Subpart K verification of the energy savings actually achieved during the fourth quarter of the year (in kilowatt hours) and resulting reductions in heat input (in mmBtu) at the unit, pursuant to the procedures set forth in the EPA Conservation Verification Protocol.

(C) The energy savings verifications of paragraphs (A) and (B) shall be certified by:

(1) An independent auditor using the procedures set forth in the EPA Conservation Verification Protocol for energy conservation measures, pursuant to 40 CFR 73.81(a); or

(2) If the utility is subject to the rate-making jurisdiction of a State regulatory authority that meets the least-cost planning (LCP) and net income neutrality (NIN) criteria set forth in 40 CFR Part 73, the verification of energy savings from demand-side measures may be certified by the State authority with rate-making jurisdiction over the utility; or

(3) For supply-side measures, verification shall not require LCP or NIN, and verification of supply-side measures may be certified by any authority with rate-making jurisdiction over the utility; if the procedures described in subparagraphs (2) and (3) for certifying energy conservation would interfere with the unit's ability to comply with the compliance certification deadlines specified in paragraphs (A) and (B), above, the verification shall be made as provided in subparagraph *(1)*. For the purposes of the energy savings verification procedures, all verified kilowatt hour savings in any calendar year from energy conservation measures then in effect shall be creditable towards reductions in utilization below baseline at Phase I affected units in that calendar year.

(D) The Administrator reserves the right to conduct independent audits of energy savings, or to otherwise ascertain that verifications provided by a Phase I affected source under this part are valid and correct.

(ii) *Verification of Shifts to Sulfur-Free Generators or to Compensating Units.* Each reduced utilization plan relying on increased generation at a sulfur-free generator or designated compensating unit shall require that the designated representative for the Phase I unit reducing its utilization

plan in accordance with the provisions of the plan and the requirements of this part. Phase I units governed by an approved utilization plan may bank all allowances freed-up by the approved reduced utilization.

(e) *Prohibitions.* (1) It shall be a violation of the Act for the owners, operators, or designated representative of any affected unit governed by a reduced utilization plan to operate any such unit except in accordance with the terms of the plan as approved by the Administrator pursuant to this section, or to fail to carry out any measure provided for in the plan, including any revisions to the plan made pursuant to Subpart J of this part.

(2) It shall be a violation of the Act for any affected source or unit to emit sulfur dioxide in excess of the emissions limitations provided for in the approved reduced utilization plan unless the unit holds allowances in its Allowance Tracking System compliance subaccount as of the allowance transfer deadline in an amount not less than the unit's total annual emissions for the year.

(3) It shall be a violation of the Act for any Appendix A unit subject to a reduced utilization plan to emit nitrogen oxides in excess of the emissions limitation applicable to that unit pursuant to 40 CFR Part 76.

(4) The owners, operators, and designated representative of the original or compensating Phase I affected unit governed by a reduced utilization plan approved by the Administrator under this section shall be liable for any violation of said plan or of this section at that or any other unit governed by the reduced utilization plan; including liability for fulfilling the obligations specified in 40 CFR Part 77 and Section 411 of the Act. Any such violation shall be a violation of the Act.

(5) *Failure to File a Plan.* (i) It shall be a violation of the Act and of this part for the owners, operators, and designated representative of any Phase I unit that reduces utilization in any calendar year as a method of compliance with the unit's Phase I emissions reduction obligations under the Acid Rain program to fail to submit a reduced utilization plan in accordance with this section.

(ii) Where a Phase I affected unit was under-utilized during a Phase I calendar year as compared to its baseline, the requirement to submit a reduced utilization plan meeting the requirements of this section shall be deemed not to be violated in that year to the extent that the designated representative demonstrates, in the annual report under § 72.402, that:

(A) The aggregate utilization for all Phase I units within the utility's system was equal to or greater than the aggregate baseline for the units; or

(B) The under-utilization was caused by a system-wide downturn in sales; provided that to the extent the percentage of under-utilization exceeds the percentage of system-wide downturn the presumption of this paragraph shall be rebuttable and shall not apply where the Administrator finds, based on clear and

(2) That the under-utilized unit did not pursue other compliance strategies sufficient to ensure compliance without reduced utilization.

(iv) Notwithstanding any demonstration under subsection (e)(5), the designated representative, owners, and operators, of the under-utilized Phase I unit shall be subject to the annual reporting requirements of § 72.402.

§ 72.44 Phase II repowering extensions.

(a) *Applicability.* This section applies to:

(1) Each source with an existing affected unit that has actual 1985 emissions rates equal to or greater than 1.2 lbs/mmBtu.

(2) Each source with a new unit that will be a replacement unit, as provided in subsection (b)(2), below, for an existing unit meeting the requirements of paragraph (a)(1).

(3) Each source with an oil and/or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991 by the Secretary of Energy.

(b)(1) The designated representative of any affected unit meeting the requirements of paragraph (a)(1) may include in the unit's Phase II Acid Rain permit application and proposed compliance plan a Phase II repowering extension plan, to comply with the Phase II sulfur dioxide requirements of the Acid Rain program, that includes a demonstration that the unit will be repowered with a qualifying repowering technology.

(2) The replacement of an existing utility unit meeting the requirements of paragraph (a)(1) with a new utility unit located at a different site using a qualified repowering technology, shall be treated as a repowering of the existing unit for purposes of this section, if:

(i) The replacement unit is designated in the proposed compliance plan to replace the existing unit; and

(ii) The existing unit will be permanently retired from service on or before the date on which the designated replacement unit commences commercial operation.

(c) *Special Procedures -- Administrator's Review of Repowering Technology.* (1) The designated representative of a unit meeting the requirements of subsection (a) seeking a repowering extension shall submit to the Administrator at any time before June 1, 1997, a petition requesting approval of a proposed repowering technology. The petition shall use SF# 7244A in Appendix C of this part, and shall include the following information in accordance with the repowering technology demonstration protocol issued, and amended from time to time, by the Administrator:

(i) Identification and description of the technology; and

(ii) Vendor guarantee estimating the following performance characteristics of the technology:

(A) Percent removal of each pollutant which is one of the multiple pollutants being controlled;

(B) Emissions rate of each pollutant identified in (A);

(C) Overall generation efficiency;

(B) Remove unit from operation to install the qualified repowering technology;

(C) Start construction;

(D) Complete construction;

(E) Start-up testing;

(F) The date the existing unit will be shut down, in the case of a plan involving the repowering of a replacement unit at a separate site; and

(G) Commence commercial operation.

(v) A requirement that by not later than January 1, 2000, the designated representative shall submit to the Administrator and the permitting authority the following additional information:

(A) Satisfactory documentation of a preliminary design and engineering effort;

(B) A copy of an executed and binding contract for the majority of the equipment to repower such unit; and

(C) Any additional information specified by the Administrator when reviewing the technology information provided in subsection (c).

(vi) A requirement that should the technology, demonstration, or information requirements of this section not be met, the approved repowering extension shall be deemed null and void.

(vii) A requirement that not later than 60 days after the repowered unit commences operation at full load, the designated representative shall submit a report comparing actual hourly emissions of any pollutant regulated under the Act at the repowered unit and at the existing unit prior to repowering.

(viii) *Shutdown Notification.* A requirement that the designated representative of the affected unit governed by an approved repowering plan shall notify the Administrator in writing, using SF# 7244B in Appendix C of this part, 60 days in advance of the date on which the affected unit for which the extension has been granted is to be removed from operation to install the repowering technology (or to be replaced).

(ix) Information concerning the status of the repowering technology approval petition required pursuant to subsection (c), including a copy of the approval, if granted, or any other determination of the Administrator the date the petition was filed with the Administrator; and if still pending any additional information required by the Administrator to be submitted.

(2) *Repowering With a Replacement Unit.* For plans proposing replacement of an existing utility unit with a new utility unit located at a different site using repowering technology each proposed repowering extension plan submitted under this section shall include, in addition to the information specified in paragraph (e)(1) of this section, the following information on SF# 7244 in Appendix C of this part:

(i) Identification of the replacement unit, in accordance with subsections (a) and (b);

(ii) Certification that the replacement unit will replace the existing unit;

operating permit issued to the source and in the approved compliance plan under Subpart I, together with the compliance schedule and other requirements necessary to ensure that the unit will meet the Phase II emission reduction requirements as provided in this section.

(3) *Allowance Allocation.* (i) The Administrator shall allocate allowances to the affected unit for use during the repowering extension period approved under this section (including a pro rata allocation for any fraction of a year) equal to the affected unit's baseline multiplied by the lesser of the unit's most stringent Federally enforceable state implementation plan emissions limitation for sulfur dioxide in each year of the extension or its actual emissions rate for 1995, in lieu of any other allowance allocation that would otherwise be authorized under the Acid Rain program. Allowances allocated under this paragraph shall not be transferrable.

(ii) Effective on the date specified in the approved repowering plan as the date on which the affected unit for which the extension has been granted will be removed from operation to install the repowering technology or will be permanently removed from service for replacement, the original affected unit or replacement unit (if any) shall be subject to the emissions limitation requirements of the Acid Rain program including allowances for sulfur dioxide as follows:

(A) Beginning with the year or portion of the year in which the existing unit is removed from operation, allowances shall be allocated annually to the existing unit calculated as the product of the unit's baseline multiplied by 1.20 lbs/mmBtu, divided by 2,000, prorated according to the date the unit is removed from operation. Such allowances shall be transferrable.

(B) Notwithstanding the provisions of 40 CFR Part 73, the allowances calculated as provided in paragraph (A) shall be allocated annually to the designated replacement unit (if any), in lieu of any further allocations of allowances to the existing unit.

(4) *Failed or Delayed Repowering Projects.* (i) If the designated representative of an existing unit granted an extension under this section demonstrates to the satisfaction of the Administrator and the permitting authority that the repowering technology specified in the approved plan for such unit was properly constructed and tested on such unit, but was unable to achieve the emissions reduction limitations specified in the plan and that it is economically or technologically infeasible to modify the technology to achieve such limits, such existing unit may be retrofitted or repowered with another clean coal or other available control technology. Notwithstanding the previous sentence, no further extension of the Phase II emissions limitation deadline shall be authorized in such cases.

(ii) If at any time on or before December 31, 2003 the designated representative notifies the Administrator that the repowering project has failed, and the Administrator determines that there has been a good faith effort to properly design,

of any new unit specified in subsection (a), each new unit shall be an affected unit subject to the Phase II requirements of the Acid Rain program, including the requirement:

(i) To hold allowances in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer date, not less than the unit's sulfur dioxide emissions for the year, and

(ii) To comply with the applicable emissions limitations for nitrogen oxides set forth in 40 CFR Part 76.

(2) To monitor emissions, beginning upon commencement of operation in accordance with the deadlines and procedures set forth in 40 CFR 75.11.

(3) Notwithstanding paragraph (b)(1) of this section, any new unit designated as a compensating unit pursuant to § 72.43, or subject to the common stack requirements as provided in § 72.50 shall be an affected unit subject to the Phase I requirements of the Acid Rain program, beginning on the date specified in those sections, and as provided in subsection (c)(3) and (4) of this section.

(c) *Permit Application Procedures and Deadlines.* (1) The designated representative of each source that includes a new unit, as provided in subsection (a)(1), shall submit a Phase II Acid Rain permit application and new unit plan, on SF# 72200 and SF# 72200A in Appendix C of this part, to the permitting authority not later than 24 months before the later of:

(i) January 1, 2000; or

(ii) The date on which the unit commences operation.

(2) The designated representative of each source that includes a unit, as provided in subsection (a)(2), shall submit a Phase II permit application and new unit plan, on SF# 72200 and SF# 72200A in Appendix C of this part, to the permitting authority not later than 24 months before the later of the date on which the unit commences operation to serve a generator with a nameplate capacity of greater than 25MWe or January 1, 2000.

(3) The designated representative of each source that includes a unit subject to this section, as provided in subsection (a), that is designated as a compensating unit in a reduced utilization plan pursuant to § 72.43, shall submit a Phase I permit application, using SF# 7231 and SF# 7231A in Appendix C of this part, to the Administrator with such compliance plan in accordance with the deadlines specified in § 72.43. Any such unit shall be subject to the requirements and deadlines applicable to Phase I affected units, shall receive no allowances and shall be deemed to have a baseline of zero.

(4) The designated representative of each source that includes a unit subject to this section, as provided in subsection (a), that utilizes a common stack with a Phase I affected unit shall submit, by the later of February 15, 1993 or 24 months before the unit commences operation, a common stack plan, as provided in § 72.50, for the unit and all other units at the source sharing the common stack. Except as provided in 40 CFR Part 75 for such units, any such unit shall be subject to the requirements and

or Phase II, that seeks to comply with the Acid Rain program nitrogen oxides emissions reductions requirements by emissions averaging with any other such unit.

(b)(1) In lieu of having each unit comply with the applicable emissions limitations under 40 CFR Part 76, the designated representative of two or more affected units subject to one or more of the applicable emissions limitations pursuant to 40 CFR Part 76 having the same owner or operator, may petition the permitting authority for alternative contemporaneous annual emission limitations for such units; *provided* that such units:

(i) Are affected units for both sulfur dioxide and nitrogen oxides;

(ii) Have the same designated representative, and owner or operator; and

(iii) Are eligible to be combined in an averaging plan pursuant to the criteria for averaging plans specified in 40 CFR Part 76 and this section.

(2) The actual annual emissions rate for nitrogen oxides (in lbs/mmBtu) averaged over the units in question, proposed in a plan pursuant to this section, must be less than or equal to the Btu-weighted average annual emissions rate for the same units if they had been operated, during the same period of time, in compliance with the applicable limitations for each such unit provided for in 40 CFR Part 76.

(c) *Submission Deadline.* (1) Proposed nitrogen oxides emissions averaging plans may be submitted at any time and are not limited in duration provided that the other requirements of this section and this part are met.

(2) The designated representative shall submit proposed averaging plans no later than 6 months prior to the end of any calendar year for the plan, if approved, to be deemed to govern operations at the units subject to the plan in that year. Applications received less than 6 months prior to the end of the calendar year shall, if approved, become effective beginning in the following calendar year.

(d) *Contents of Proposed Plan.* Each proposed nitrogen oxides emissions averaging plan shall be submitted, on the SF# 7246, as provided for in 40 CFR Part 76, and shall include the following:

(1) Identification of each unit proposed to be governed by the plan and their common owners or operators;

(2) Certificates of representation, in accordance with Subpart B of this part, for the designated representatives for the units proposed to be governed by the plan;

(3) The actual annual total emissions (tons/year) and annual average emissions rate (lbs/mmBtu) from each unit proposed to be governed by the plan for the three preceding years of operation;

(4) A certification that each unit is equipped with an emissions monitoring system certified and operated in accordance with 40 CFR Part 75;

(5) The dates during which the averaging plan is proposed to be in effect;

appropriate to ensure compliance with the requirements of this part and 40 CFR Part 76.

(2) *Issuance of Operating Permit.* Following approval of an averaging plan, the permitting authority shall issue an operating permit to each source with a unit governed by the plan incorporating such plan in accordance with this part and 40 CFR Part 76. If the permitting authority determines that the proposed averaging plan does not meet the requirements of this section, the operating permit(s) issued by the permitting authority in accordance with this part shall require compliance by each unit with the applicable nitrogen oxides emissions limits specified for such unit in 40 CFR Part 76.

(3) The emissions limitations in the approved averaging plan shall only remain in effect while all the units that are part of the averaging plan continue operating under the conditions specified, in accordance with this section and 40 CFR Part 76, in the approved plan and in each unit's respective operating permit including operation by each unit within the range of utilization (in mmBtu) for the year and fuel type specified in the plan as approved.

(f) *Prohibitions.* (1) No plan shall be approved under this section unless actual annual emissions of nitrogen oxides authorized by the plan are less than or equal to the actual annual emissions that would have been emitted had each unit operated in compliance with its applicable emissions limitation under 40 CFR Part 76.

(2) It shall be a violation of the Act and of the source's permit to operate the units subject to a nitrogen oxides emissions averaging plan approved pursuant to this section so as to exceed the emissions limitations, specified in the approved plan, or so as to fail to fulfill the requirements specified in the approved permit and nitrogen oxides emissions averaging plan.

(3) Failure of the designated representative to notify the permitting authority of operating changes specified in the approved plan pursuant to subsection (c)(12) above, shall be a violation of the Act.

(4) The owners, operators, and designated representative of the units governed by an approved nitrogen oxides emissions averaging plan shall be liable for any violation by any such unit or any other unit governed by the plan or this section, Part 76, or the plan, including liability for a failure to fulfill the obligations specified in 40 CFR Part 77 and Section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.47 Phase I or phase II nitrogen oxides alternative emissions limitations plans.

(a) *Applicability.* The provisions of this section shall apply to any affected unit that is a boiler subject to a nitrogen oxides emissions limitation under 40 CFR Part 76 during Phase I or Phase II, for which an alternative emissions limitation for nitrogen oxides is sought.

alternative emissions limitation to the permitting authority at least 3 months before the end of the calendar year in order for the alternative demonstration period emissions limitation, if approved, to govern operations during that year.

(d) *Contents of Proposed Plan.*

(1) *Demonstration Period Plan.* The application for approval of a demonstration period shall be submitted on a Nitrogen Oxides Alternative Emissions Limitation Demonstration Period Plan SF# 7247 in Appendix C of this part, and shall include the following information:

(i) The unit name and identification number.

(ii) A certification by an independent auditor, in accordance with the requirements set forth in 40 CFR Part 76, that the conditions specified in subsection (b) apply to the unit, including:

(A) That the appropriate control equipment designed to meet the applicable emissions limitation at the unit was properly installed, and has been properly operated for a period of no less than 6 months, including a vendor certification that there is no adjustment to the equipment that can be done such that the unit would be able to achieve the applicable limit of 40 CFR Part 76; or

(B) In lieu of the requirements in paragraph (A), *(1)* a list of all vendors of equipment (name address, phone number) designed for the unit's boiler type, *(2)* identification of which vendors, of those listed pursuant to the preceding subparagraph, were contacted by the source, and the date each vendor was contacted for purpose of supplying such equipment, *(3)* copies of any solicitations for bids, purchase orders, or nitrogen oxides control equipment design, engineering, and construction contracts, and *(4)* the certification of the vendors contacted that technology cannot be designed for that unit which will meet the applicable limitation of 40 CFR Part 76;

(iii) Operating information and monitoring data, collected by an emissions monitoring system certified in accordance with the requirements of 40 CFR Part 75 (emissions monitoring regulations), for the same period identified in subparagraph (ii)(A) that demonstrates in accordance with this section and 40 CFR Part 76 that the unit cannot meet the applicable limitation of 40 CFR Part 76;

(iv) A proposed interim alternative emissions limitation that the unit shall meet on an annual average basis during the demonstration period, calculated in accordance with 40 CFR Part 76;

(v) The operating and recordkeeping requirements that would apply to the unit during the demonstration period, in accordance with 40 CFR Part 76, including the design engineering and operating protocol;

(vi) A statement that the demonstration plan, if approved, will be conditional on the subsequent timely submission by the designated representative of periodic compliance certifications submitted in accordance with Subpart K and 40 CFR Part 76 to

(2) *Final Alternative Emissions Limitation Plan.* (i) If the permitting authority determines that the final nitrogen oxides alternative emissions limitation plan meets the requirements of subsections (a) through (d)(2), the Administrator shall approve the plan. If the final limit is more stringent than the demonstration period limit the permitting authority may include as part of the plan as approved a schedule for the unit to achieve compliance with the limit as expeditiously as practicable. Thereafter, the permitting authority shall issue an operating permit, or revise the operating permit for the source in accordance with § 72.301 (permit modification) for the source in question, in accordance with this part and 40 CFR Part 76, incorporating the plan as approved and authorizing the unit governed by the plan to be operated during the remainder of the permit term pursuant to the emissions limitation and operating conditions specified in the approved plan.

(ii) Each permit renewal application for a source with a unit governed by a plan approved under this section shall include a demonstration, in accordance with 40 CFR Part 76, justifying the continued applicability of an alternative limit to the unit. If the alternative limit proposed as part of a renewal application is more stringent than the previously approved alternative limit, and shows progress by the unit toward meeting the applicable limit of 40 CFR Part 76, such limit shall be deemed automatically approved.

(f) *Prohibitions.* (1) It shall be a violation of the Act for any unit subject to an alternative emissions limitation to emit in excess of the applicable limit established in accordance with this section and 40 CFR Part 76.

(2) The owner or operator and the designated representative of any unit operated in violation of this section and 40 CFR Part 76 shall be fully liable for such violation, including liability for fulfilling the obligations specified in 40 CFR Part 77 and Section 411 of the Act.

(3) It shall be a violation of the Act for a unit with an approved nitrogen oxides alternative limitation plan to emit nitrogen oxides during the demonstration period in excess of the limitation assigned pursuant to 40 CFR Part 76.

(4) At the conclusion of the demonstration period, it shall be a violation of the Act for a unit with an approved nitrogen oxides alternative limitation plan to emit nitrogen oxides in excess of the final emissions limitation approved by the permitting authority pursuant to this section and 40 CFR Part 76.

§ 72.48 Phase I nitrogen oxides compliance deadline extension plans.

(a) *Applicability.* The provisions of this section shall apply to any affected unit that is a boiler subject to the nitrogen oxides emissions limitation under 40 CFR Part 76 during Phase I and that seeks an extension of the Phase I nitrogen oxides emissions reductions compliance deadline (January 1, 1995).

(3) Start-up testing of the technology; and
(4) Commencement of operation.
(D) Such other information as required in 40 CFR Part 76, including the applicable test method for demonstrating compliance and all recordkeeping and compliance certification requirements that will apply under the plan.
(ii) *Emissions Limitations and Operational Standards.* Each proposed compliance plan submitted under this section shall specify, in accordance with 40 CFR Part 76:
(A) Extension period requirements, as specified in 40 CFR Part 76;
(B) The final emissions limitation and compliance deadline that will apply.
(C) The test method for determining compliance with the nitrogen oxides emissions limitations applicable to a unit pursuant to a plan approved in accordance with this section, determined in accordance with 40 CFR Part 76 and the monitoring recordkeeping and reporting requirements of 40 CFR Part 75.
(iii) Design, equipment, work practice or operational standards as specified in 40 CFR Part 76.
(3) *Recordkeeping Requirements.* Each proposed compliance plan submitted under this section shall specify requirements for maintaining records at the source, in accordance with 40 CFR Part 76.
(4) *Reporting/Compliance Certification Requirements.* Each proposed compliance plan submitted under this section shall specify compliance certification requirements, in accordance with Subpart K of this part and 40 CFR Part 76, including notices concerning the achievement of any scheduled increments of progress.
(e) *Administrator's Action on Proposed Plan.* (1) The Administrator shall act on each proposed extension plan within 3 months of receipt as provided in 40 CFR Part 76.
(2) The Administrator may deny the proposal, or approve the proposed extension plan in whole or in part with such conditions as may be appropriate to ensure expeditious compliance with the Phase I emissions limitations applicable to the unit under 40 CFR Part 76. The Administrator shall grant an extension that terminates upon commencement of operation of the nitrogen oxides control equipment, but not longer than 15 months.
(f) *Prohibitions.* The owner or operator and the designated representative of any unit governed by a compliance plan approved by the Administrator in accordance with this section and 40 CFR Part 75 and Part 76 shall be liable for such violation, including liability for a failure to fulfill the obligations specified in 40 CFR Part 77 and Section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.49 Phase I or phase II opt-in plans.

(a) This section shall apply to sources eligible to opt-in to the Acid Rain program, as provided in 40 CFR Part 74.

the Phase I requirements of this part and Parts 73-78, including the requirement to hold allowances equal to or greater than its annual sulfur dioxide emissions beginning on the later of January 1, 1995 or commencement of operation. Such unit shall receive no allowances and shall have a baseline of zero.

(3) Where an affected unit and a non-affected unit utilize a common stack and the emissions from such units are not separately monitored by emissions monitoring systems certified and operating in accordance with 40 CFR Part 75, the designated representative shall identify the common-stack in the proposed monitoring plan for the source using SF# 7512 in Appendix C of this part and shall designate the non-affected unit as an opt-in unit and submit an opt-in plan in accordance with 40 CFR Part 74 and § 72.49 on the form specified in 40 CFR Part 74.

(4) Where two or more units share a common stack, and where not all of the units are otherwise subject to Acid Rain nitrogen oxides requirements, the units shall either separately monitor their nitrogen oxides emissions or otherwise differentiate their emissions, in accordance with the monitoring requirements of 40 CFR Part 75, or all emissions from the units shall be subject to the most stringent Acid Rain nitrogen oxides emissions limitation applicable to any one of the units sharing the common stack. For two or more units that are subject to Acid Rain nitrogen oxides requirements that cannot be separately monitored or where the emissions cannot otherwise be differentiated pursuant to 40 CFR Part 75, the unit shall either average their emissions pursuant to 40 CFR Part 76, or they shall be subject to the most stringent limit.

(c) All units governed by a common-stack plan shall have one designated representative.

(d) No permit shall be issued to a source with units sharing a common stack unless the requirements of this section are met. Notwithstanding any other provisions of this part, no common-stack plan may be submitted as a conditional compliance option.

(e) The requirements of paragraphs (b)-(d) shall not apply where each unit is equipped with a fully certified continuous emissions monitoring system to differentiate the emissions from the respective units.

(f) *Prohibitions.* The owner or operator and the designated representative of any unit governed by a compliance plan approved by the Administrator in accordance with this section and 40 CFR Part 75 and Part 76 shall be liable for such violation, including liability for a failure to fulfill the obligations specified in 40 CFR Part 77 and Section 411 of the Act. Any such violation shall be a violation of the Act.

(i) *Alternative Monitoring Systems.* (1) Data from an alternative monitoring system shall be authorized by the permit in lieu of continuous emissions monitoring system data only if collected pursuant to an alternative monitoring method approved by the Administrator pursuant to 40 CFR Part 75, and incorporated into the permit pursuant to subparagraph (ii). Such approval shall specify the required installation schedule and operating conditions of the alternative monitoring system, appropriate quality assurance methods, frequency and parameters for testing, and the method that shall apply to calculate emissions when data from the system is unavailable. The approval documentation requirements shall be expressly incorporated into the permit for the unit. Failure to operate the alternative monitoring system in accordance with the conditions of the Administrator's approval of the method shall be deemed a violation of the permit.

(2) Any approval by the Administrator of an alternative monitoring system shall be incorporated into the permit without modification or revision by the permitting authority as an administrative amendment pursuant to § 72.303.

(j) Each Acid Rain permit issued pursuant to this part, 40 CFR Part 70 or 71 shall provide that:

(1) The affected source governed by the permit shall retain records of:

(i) All monitoring information, including all calibration and maintenance records;

(ii) Copies of all reports required by this part;

(iii) The raw emissions and operational data used to generate the reports; and

(iv) Records of all information used to complete the permit application.

(2) All such records shall be retained pursuant to § 72.10.

(3) All applications, reports, or information submitted to the permitting authority shall be signed and certified pursuant to § 72.9 and Subpart K of this part. Each Acid Rain permit shall incorporate the definitions contained in the Act, as supplemented by this part, and 40 CFR Parts 73-78, by reference without modification.

(4) It shall be a violation of the permit and of the Act for a source to fail to comply with any permit provision including the requirement to submit the emissions monitor verification data, or to obtain certification of a monitor, as required by subsection (f)(2) of this section and 40 CFR Part 75, in a timely manner.

§ 72.52 Compliance plan.

(a) The compliance plan and all of its terms, requirements, and conditions, as approved or revised by the permitting authority in accordance with this part, shall accompany, be incorporated into and deemed a part of any Acid Rain permit issued pursuant to this part or 40 CFR Part 70 or 71.

(b)(1) Each permit shall require that the affected unit hold allowances in its Allowance Tracking System compliance subaccount

compliance with any conditions imposed by the Administrator when issuing the determination of completeness) that complies with the requirements of this part and 40 CFR Parts 73-78 shall be deemed to be operating in compliance with the terms and requirements of the Acid Rain program and Title IV of the Act, unless and until such permit application and proposed compliance plan are disapproved by the permitting authority. The terms and conditions of an Acid Rain permit issued for an affected source under this part shall supersede the Acid Rain permit application and proposed compliance plan for the unit on the permit's issuance date.

§ 72.54 Prohibitions and standard conditions.

(a) *General.* Each Acid Rain program permit and permit application shall specify the duties, prohibitions and provisions and duties, prohibitions and such provisions shall apply to and be binding on the affected source named in the permit or permit application, all affected units at the source, all other units governed by the terms of the compliance plan submitted with the permit application, and all owners, operators and designated representatives of all source(s) and unit(s) named in the permit application or governed by the permit and any applicable compliance plan (including any new owners and operators as provided in § 72.24 and § 72.200(h)).

(b) *Duties, Prohibitions and Liability.*

(1) *Duties.* Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR Part 72. The duties are as follows:

(i) To submit a permit application and proposed compliance plan under 40 CFR Part 72 in accordance with the deadlines specified in § 72.30;

(ii) To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application.

(iii) To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with Title IV of the Act and of 40 CFR Part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority.

(iv) To operate the unit in compliance with the monitoring requirements of 40 CFR Part 75.

(v) In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR Part 77; and

(vi) In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning

this source shall comply with all the emissions monitoring requirements of 40 CFR Part 75, including:

(A) The duty to collect and report emissions data for each unit at the source and to adopt quality assurance procedures and conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR Part 75; and

(B) The duty to calculate emissions pursuant to the missing data provisions of 40 CFR Part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required;

(ii) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.

(iii) No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR Part 75, and the unit operates the system in accordance with that approval.

(2) *Recordkeeping and Reporting Requirements.* (i) The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application.

(A) The certificate of representation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR Part 72, Subpart B.

(B) All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR Part 75;

(C) Copies of all reports required by 40 CFR Parts 72-78; and

(D) Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.

(ii) The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR Part 72 Subpart K and other provisions of 40 CFR Parts 72-78.

(3) *Allowance Information.* (i) An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of Title IV of the Act and 40 CFR Parts 72-78. Nothing in Title IV, in 40 CFR Parts 72-78, in this permit application, or in any provision of law shall be construed to

monitoring system has been installed and is being operated to monitor the emissions from each Phase I affected unit at the source, including any substitution, compensating, or opt-in unit, that all data is being quality assured, that records and reports are being kept, and that the system is eligible for certification in accordance with 40 CFR Part 75.

§ 72.61 Administrator's action on phase I permit applications and compliance plans.

(a) *Administrator's Action on Phase I Applications and Compliance Plans.* (1) The Administrator shall review and issue a permitting decision, in accordance with the procedures set forth in Subpart G of this part, on each complete Acid Rain Phase I permit application and proposed compliance plan submitted by a designated representative for a source under this paragraph, determining whether the submission satisfies the requirements of Title IV of the Act, of this part, and of 40 CFR Parts 73-78 within 6 months of receipt of the complete submission at the appropriate U.S. EPA Regional office; *provided* that the Administrator shall not review any Acid Rain program submission for an affected source or unit unless made by a designated representative who has been duly certified for the source or unit, as provided in Subpart B; *provided* further that the Administrator shall not be required to issue a permitting decision within 6 months where the applicant has failed to submit a complete application.

(2) Acid Rain permit applications and compliance plans that meet the requirements of Title IV, of this part, and of 40 CFR Parts 73-78, shall be approved, in whole or in part, and with such modifications or conditions as may be appropriate. All other applications and proposed compliance plans shall be denied, subject to subsections (c) through (e). A notice of denial shall be sent to the source stating the reasons of the denial, and shall be a permitting decision under this part.

(b) *Approved Applications and Compliance Plans.* (1) The Administrator shall issue a proposed Phase I Acid Rain permit for each affected source for which an Acid Rain permit application and compliance plan have been approved or modified as provided in subsection (a) or (c). Issuance or denial of the permit shall constitute an permitting decision for purposes of any appeals under Subpart H.

(2) Each Phase I Acid Rain permit issued by the Administrator shall become effective January 1, 1995, and shall have a term of 5 years commencing on its effective date.

(3) Prior to the effective date of the Phase I permit issued by the Administrator, the approved Phase I Acid Rain permit application and compliance plan shall be binding on the designated representative, owners, and operators of the affected source for purposes of this part and 40 CFR Parts 73-78; and shall be enforceable in lieu of the permit until the effective date of the permit. Thereafter, the affected source and its

source shall be thereafter liable for operating the affected unit without a permit, as provided in § 72.53(a), until such time as a complete permit application and proposed compliance plan meeting the requirements of the part are submitted to the Administrator.

Subpart G—Federal Acid Rain Permit Issuance Procedures

§ 72.70 General.

(a) *Scope.* This subpart contains the procedures for Federal issuance of Acid Rain permits for Phase I of the Acid Rain program, and for Phase II for sources located in States where the Administrator is the permitting authority as provided under 40 CFR Part 71. Except as expressly provided in this part, the procedures in this subpart do not apply to Acid Rain permitting by State or local permitting authorities with programs approved under 40 CFR Part 70. The Acid Rain permit program requirements that must be adopted by States and localities in order to gain approval for an operating permit program under 40 CFR Part 70 are set forth in Subpart I of this part.

(b) *Permit Decision Deadlines.* (1) The permit decision deadlines set forth in Subpart F shall apply to Phase I permitting. The permit decision deadlines set forth in Subpart I shall apply to decisions on initial Phase II permit applications.

(2) *Phase II Permit Renewals.* The Administrator shall issue a permitting decision on Phase II permit renewal applications within 6 months of receipt of a complete renewal application meeting the requirements of this part, not including periods during which the source is required to provide additional information, unless the Administrator modifies this deadline.

(3) Even though a permit application for an affected source is deemed complete as provided in § 72.72(a), the deadline for the Administrator to make a permitting decision on the application shall not begin to run where the designated representative for the source subsequently fails to submit in a timely manner supplemental information required by a notice for supplemental information issued by the Administrator. The Administrator shall deny the application if the designated representative fails to submit the supplemental information required within the time required by the Administrator, not to exceed 12 months from the date the permit application was first submitted.

§ 72.71 Acid rain permit program forms.

The Administrator shall use the Acid Rain program forms specified in Appendix C of this part in developing the Acid Rain permit. These forms include Acid Rain permit application forms, proposed compliance plan forms, and Acid Rain permit forms. The Administrator will submit the data contained in these forms through an automated system, the Acid Rain Permit program Electronic Application and Reporting System.

designated representative to collect and submit the required information, not to exceed 60 days from the date the permit application was first submitted to the Administrator.

(ii) A failure to submit the supplemental information within the required time period shall result in a denial of the permit. Such denial shall be considered a permitting decision for purposes of any permit appeals pursuant to Subpart H.

§ 72.73 Proposed permit.

(a) After the Administrator receives all supplemental information requested by notice, the Administrator shall issue or deny a proposed permit for the affected source.

(b) Each proposed Acid Rain permit shall set forth, expressly or by reference, and require compliance with:

(1) All applicable requirements specified in Subpart E of this part including a proposed compliance plan, and 40 CFR Parts 73-78, including any appendices thereto;

(2) All applicable monitoring and reporting requirements set forth in 40 CFR Part 75; and

(3) All applicable requirements concerning allowances, as set forth in 40 CFR Parts 73 and 74.

(c) The proposed permit shall be based on the information submitted by the designated representative for the affected source and such other information as required by § 72.74 to be developed for the administrative record.

(d) The proposed permit shall be accompanied by a statement of basis in accordance with § 72.75.

(e) The application and compliance plan as approved or modified by the Administrator proposed permit shall continue to be binding on the source until the affected date of the permit issued by the Administrator for that source, in accordance with the deadlines specified in § 72.61(a)(1), or § 72.205(b)(1) and (2).

§ 72.74 Permit administrative record.

(a) *Applicability.* The Administrator shall prepare an administrative record for all proposed permits and permitting decisions.

(b) *Contents of the Permit Administrative Record.* (1) The administrative record for a proposed permit shall include:

(i) The permit application, the proposed compliance plan, and any supporting data submitted by the designated representative;

(ii) The proposed permit;

(iii) A statement of basis as described in § 72.75;

(iv) Copies of all documents cited in the statement of basis, or the location of these documents; and

(v) Other documents relied on by the Administrator to develop the proposed permit, including any records of discussions or conferences with the permittee or other interested persons regarding the proposed permit.

(iv) The reopening of a permit for cause pursuant to 40 CFR Part 70.

(2) Any public notice of a proposed permit given under this subpart may be for one or more proposed permits.

(b) *Timing.* Public notice under this subpart shall provide for:

(1) A 30-day public comment period, beginning from the date of publication of the notice of a proposed permit; and

(2) An opportunity to request a public hearing on the proposed permit, including a scheduled date and place for the hearing if requested, to occur not earlier than 15 days after the notice is given.

(c) *Methods.* The Administrator shall give the public notice of the proposed permit required by this section, as follows:

(1) Actual notice shall be given to the following persons (except to the extent any such person has waived his or her right to receive such notice for any class or category of permit action):

(i) The designated representative;

(ii) The State or local air pollution agency and the State utility rate regulatory authority (if any) with jurisdiction over the affected source governed by the proposed permit;

(iii) In accordance with Title V of the Act, the State or local air pollution agency for any contiguous State whose air quality may be affected by the affected source that is the subject of the permit action, or for any State located within a 50-mile radius of the affected source; and

(2) Notice by publication in the FEDERAL REGISTER and in a journal of general circulation in the area affected by the proposed permit, as provided in 40 CFR 70.8.

(d) *Contents.* All public notices issued under this part shall contain the following information:

(1) Name and address of the EPA office processing the proposed permit for which the notice is being given;

(2) Name, address, telephone and facsimile number of the designated representative for the affected source;

(3) Identification of each affected unit at the source covered by the proposed permit as follows: name (plant, unit), address;

(4) A brief description of the action proposed to be taken; including for proposed permits:

(i) The basic allowance allocation for the affected unit or units covered by the permit;

(ii) Any alternative methods of compliance that are proposed to be approved; and

(iii) Any alternative monitoring system that is proposed to be approved.

(5) The address and office hours of a public location where the administrative record is available for public inspection; and a statement that all information submitted by the designated representative and not protected as confidential pursuant to Section 114(c) of the Act is available for public inspection as part of the administrative record;

(3) Persons who do not wish to raise issues on the proposed permit action, but who wish to be notified of any subsequent permit actions concerning the permit may so indicate in writing during the public comment period or at any other time, and their names shall be placed by the Administrator on a list of interested persons.

§ 72.78 Opportunity for public hearing.

(a) During the public comment period provided under § 72.76, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the nature of the issues proposed to be raised in the hearing.

(b) The Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that:

(1) A request for such has been made that raises significant issues affecting the terms and conditions of the permit and such hearing would contribute to the permitting exercise; or

(2) A hearing might clarify one or more issues raised by the proposed permit.

(c) Public notice of the scheduling of a public hearing shall be given as specified in § 72.76.

(d) During a public hearing under this section, any person may submit oral or written comments concerning the proposed permit. The Administrator may set reasonable limits on the time allowed for oral statements, shall require the submission of written summaries of each oral statement, and may extend the public comment period by so stating during the hearing.

(e) The Administrator shall assure that a record is made of the hearing, which shall be made part of the administrative record.

§ 72.79 Response to comments.

(a) The Administrator shall consider comments received during the public comment period and shall respond in writing to such comments when issuing the permitting decision.

(b) The response to comments shall:

(1) Identify any permit provision which has been changed in the permitting decision in response to comments made, and the reasons for the change; and

(2) Briefly describe and respond to comments on the proposed permit.

(c) Any documents cited in the response to comments shall be included in the administrative record, or their location shall be cited, if readily obtainable.

§ 72.80 Issuance and effective date of acid rain permits.

(a) After the close of the public comment period, the Administrator shall make a permitting decision. The Administrator shall give actual notice of the permitting decision to the designated representative for the affected source, and to

(1) The issuance or denial by the Administrator of a permit under this part;

(2) The Administrator's approval or disapproval of a proposed excess emissions offset plan under 40 CFR Part 77;

(3) A determination by the Administrator of whether a demonstration required under this part, or a proposed technology meets the criteria for approval of a compliance option under Subpart D, including a determination under § 72.44 whether a proposed technology is a qualifying repowering technology; and

(4) Any other permitting decision of the Administrator.

(c) The following decisions of the Administrator under the Acid Rain program shall not be appealable pursuant to this subpart:

(1) Receipt and reliance on a certificate of representation submitted by a designated representative in accordance with Subpart B of this part;

(2) Approval or disapproval of a proposed alternative emissions monitoring system under 40 CFR Part 75; and

(3) Any other action of the Administrator under 40 CFR Parts 73-76.

(d) A petitioner appealing a permitting decision under this subpart shall file a petition for review with the U.S. EPA, Office of the Administrator c/o the Chief Judicial Officer (CJO), with copies sent to the U.S. EPA Acid Rain Division, the U.S. EPA Regional Office for the Region in which the affected unit is located, and with the State air management agency for the State where the permitted source is located at the respective addresses provided in § 72.4.

§ 72.91 Petition for review and request for evidentiary hearing.

(a) The following persons may petition for review of a permitting decision of the Administrator, and may include in the petition a request for evidentiary hearing:

(1) The designated representative for the affected source; or

(2) Any interested person.

(b) Within 30 days following issuance of a permitting decision by the Administrator under this part or 40 CFR Parts 73-78, any person meeting the criteria under subsection (a) may file a petition with the Administrator for review of the decision, which may include a request for an evidentiary hearing to resolve any disputed issue of material fact concerning the permitting decision. That person shall simultaneously serve a copy of the petition on each interested person and on the designated representative of the source covered by the permit unless the designated representative is the petitioner.

(c) The petition for review under this subpart shall state with specificity:

(1) Each material factual and legal issue alleged to be in dispute, and any such factual issue for which an evidentiary hearing is sought;

(2) A clear and concise brief in support of the petition, explaining why the factual or legal issues are material, and, if

unless previously submitted as part of the administrative record for the permitting decision;

(2) Notwithstanding paragraph (1), State or Federal statutes and regulations, judicial decisions published in a national reporter system, officially issued EPA documents of general applicability, and any other publicly and generally available reference material may be incorporated by reference. Any party incorporating materials referred to in this paragraph into a submission under this subpart by reference shall provide copies of the materials upon request, and as instructed by, the Administrator or the Presiding Officer.

(3) If any part of any submission is in a foreign language, it shall be accompanied by an English translation verified by the person making the translation, under oath, to be complete and accurate, together with the name, address, and a brief statement of the qualifications of the person making the translation. Translations submitted of material originally produced in a foreign language shall be accompanied by copies of the original material.

(4) Where relevant data or information is contained in a document also containing irrelevant matter, either the irrelevant matter shall be deleted or an index to the relevant portions of the document shall be included in the document.

(5) Failure to comply with the requirements of this section or any other requirement in this subpart may result in the noncomplying portions of the submission being excluded from consideration. If the Administrator or the Presiding Officer, determines on motion by any party or sua sponte, that a submission fails to meet any requirement of this subpart, the Administrator or Presiding Officer may return the submission, together with a reference to the applicable requirements on which the determination is based. A party whose materials have been rejected has 7 days, from the date the materials are returned to correct the materials in conformance with this subpart and resubmit them, unless the Administrator or Presiding Officer authorizes, on the basis of good cause shown, a longer time.

(c) The filing of a submission shall not mean or imply that the submission, in fact, meets all applicable requirements, that the submission contains reasonable grounds for the action requested, or that the action requested is in accordance with law.

(d) An original and two copies of any written submission relating to a review under this subpart submitted after notice of the granting of a petition for review is published pursuant to § 72.97, shall be filed with the Administrator and, in the event a request for a hearing is granted pursuant to § 72.9, with the Hearing Clerk (except where the Presiding Officer has requested that the copy be served on the Presiding Officer).

(e) The party filing any submission in a proceeding under this subpart shall also serve a copy of the submission upon the designated representative of each unit involved in the permitting decision and upon each party to the proceeding.

(d) If a petition for review is denied by the Administrator, in whole or in part, the Administrator shall briefly specify in writing the reasons for the denial. The denial shall be a final Agency action subject to review under Section 307 of the Act.

(e) If a petition for review is granted by the Administrator but no evidentiary hearing will be held, the Administrator shall issue a decision pursuant to § 72.108(c). The standard of review set forth at § 72.100 shall govern the decision of the Administrator.

(f) If the Administrator grants a petition for an evidentiary hearing, in whole or in part, he or she shall identify the portions of the permitting decision that have been contested by the petitioner and with regard to which any evidentiary hearing has been granted. Portions of the permitting decision that are not contested or for which the Administrator has denied the petition for review shall not be considered at the evidentiary hearing.

(g) To the extent that a request for an evidentiary hearing is granted for certain disputed factual issues, the Administrator shall refer the petition to the Chief Administrative Law Judge and, at his or her discretion, may also refer for decision all or a portion of the remaining legal or factual issues for review to the Chief Administrative Law Judge.

(1) The Chief Administrative Law Judge shall thereafter designate an Administrative Law Judge as Presiding Officer to conduct the evidentiary hearing. In addition, upon granting a request for an evidentiary hearing, the Administrator shall designate the EPA trial staff.

(2) If all parties to such a hearing waive in writing their statutory right to have an Administrative Law Judge named as the Presiding Officer in a hearing subject to this subpart, the Chief Administrative Law Judge may name a lawyer permanently or temporarily employed by the Agency and without any prior connection with the proceeding to serve as Presiding Officer.

§ 72.95 Stays of contested acid rain requirements pending appeal.

(a) A contested permitting decision of the Administrator may be stayed, in whole or in part consistent with subsection (b), by the Administrator or the Presiding Officer upon request or sua sponte during an appeal proceeding under this subpart only to the extent necessary to prevent irreparable injury pending final Agency action.

(b) The following permit requirements shall in no event be stayed due to any appeal of the Administrator's permitting decision and shall be fully effective and enforceable:

(1) The requirement that an affected unit hold as of the allowance transfer deadline, sufficient allowances in its Allowance Tracking System compliance subaccount to cover its sulfur dioxide emissions in the preceding calendar year;

for inclusion in the record of the proceeding under this subpart all written ex parte communications or a memoranda stating the substance of any oral communication together with all written responses and memoranda stating the substance of all oral responses.

(b) Whenever any member of the decisional body receives an ex parte communication made or knowingly caused to be made by a party or representative of a party to a proceeding under this subpart, the person presiding over the proceedings then in progress may, to the extent consistent with justice, require the party to show good cause why its claim or interest in the proceedings should not be dismissed, denied, disregarded, or otherwise adversely affected on account of these violations.

(c) The prohibitions of this section shall begin to apply upon issuance by the Administrator of the notice of the granting of a petition under § 72.97. This prohibition terminates at the date of final Agency action.

§ 72.99 Intervenors.

(a) Any interested person may submit a motion for leave to be admitted as an intervenor in any appeal proceeding (including any evidentiary hearing under this subpart) no later than 15 days after notice is given under § 72.97 that the petition for review has been granted or after notice is given under § 72.108(c) that a proposed decision following an evidentiary hearing will be reviewed. A motion for leave to intervene under this section shall set forth the grounds for the proposed intervention. Late motions may be granted only for good cause shown.

(b) The Administrator or Presiding Officer shall grant a motion to intervene only upon an express finding that:

(1) The motion to intervene raises matters relevant to the factual or legal issues to be reviewed.

(2) The intervenor has demonstrated a substantial interest in the outcome of the pending proceeding.

(3) The intervenor has consented to be bound by:

(i) Prior stipulations by and between the existing parties; and

(ii) All orders previously entered in the proceeding.

(4) Intervention would promote the interests of justice and will not cause undue delay or prejudice to the rights of the existing parties.

§ 72.100 Standard of review.

On appeal of a permitting decision of the Administrator, the petitioner shall have the burden of going forward and of persuasion to show that a finding of fact or conclusion of law underlying the permitting decision is clearly erroneous or that an exercise of discretion or policy determination underlying the permitting decision is arbitrary and capricious or otherwise warrants review.

the subsequent course of the proceeding unless modified by the Presiding Officer for good cause shown.

§ 72.102 Evidentiary hearing procedure.

(a) If a petition for an evidentiary hearing is granted, the Presiding Officer shall conduct a fair and impartial hearing on the record, take action to avoid unnecessary delay in the disposition of the proceedings, and maintain order. For these purposes, the Presiding Officer may:

(1) Hold pre-hearing conferences under § 72.101;

(2) Administer oaths and affirmations;

(3) Regulate the course of the hearings and govern the conduct of participants;

(4) Examine witnesses;

(5) Identify and refer issues for interlocutory decision under § 72.107;

(6) Rule on, admit, exclude or limit evidence;

(7) Establish the time for filing motions, testimony, and other written evidence, briefs, and other submissions;

(8) Rule on motions and other pending procedural matters, including but not limited to motions for summary disposition in accordance with § 72.103;

(9) Order that the hearing be conducted in stages whenever the number of parties is large or the issues are numerous and complex;

(10) Allow such direct and cross-examination of witnesses for which testimony was submitted, as provided in the scheduling order under § 72.101(a), as may be necessary to resolve disputed issues of material fact; provided that no direct or cross-examination shall be allowed on questions of law or policy, or regarding matters that are not subject to challenge in the evidentiary hearing; and provided further that the party seeking the direct or cross-examination has the burden of demonstrating that these standards have been met; and

(11) Allow the hearing to be open to the public. Where the Presiding Officer determines that the hearing should be open to the public, he or she shall provide notice in the FEDERAL REGISTER and actual notice to the designated representative and all interested persons no later than 15 days prior to commencement of the hearing; and

(12) Take any other action not inconsistent with the provisions of this subpart for the maintenance of order at the hearing and for the expeditious, fair, and impartial conduct of the proceeding.

(b) All direct and rebuttal evidence at an evidentiary hearing shall be submitted in written form, unless, upon motion and good cause shown, the Presiding Officer, in his or her discretion, determines that oral presentation of the evidence on any particular factual issue will materially assist in the efficient resolution of the issue.

filed under subsection (c) of this section or that the oral argument or submission of briefs is completed.

(e) If all factual issues are decided by summary disposition prior to the hearing, no hearing will be held and the Presiding Officer shall issue a proposed decision under § 72.106. If a summary disposition is denied or if partial summary disposition is granted, the hearing shall proceed on the remaining issues.

§ 72.104 Record of appeal proceeding.

(a) The proposed decision issued by the Presiding Officer, transcripts of oral hearings or oral arguments, written direct and rebuttal testimony, and any other written material of any kind submitted in the proceeding shall be part of the record and shall be available to the public, in the office of the Hearing Clerk, as soon as it is received in that office.

(b) Hearings and oral arguments shall be recorded as specified by the Presiding Officer, and thereupon transcribed. After the hearing or oral argument, the reporter shall certify and file with the Hearing Clerk:

(1) The original transcript, and

(2) Any exhibits received or offered into evidence at the hearing.

(c) The Hearing Clerk shall promptly notify each of the parties of the filing of the certified transcript of the proceedings. Any party who desires a copy of the transcript may obtain a copy from the Hearing Clerk upon payment of costs.

(d) The Presiding Officer shall allow witnesses, parties, and their counsel an opportunity to submit written proposed corrections of the transcript necessary to correct errors made in the transcribing. No more than 7 days shall be allowed for submitting such corrections from the day a complete transcript of the hearing becomes available. Such corrections shall be incorporated into the certified transcript along with any objections made to proposed corrections filed within 7 days of the submission of the corrections.

§ 72.105 Proposed findings and conclusions and supporting brief.

Within 45 days after the certified transcript of the hearing is filed, any party may file with the Hearing Clerk proposed findings and conclusions on the issues referred to the Presiding Officer and a brief in support thereof. Briefs shall contain appropriate references to the record. A copy of these findings and conclusions and brief shall be served upon all other parties of record and the Presiding Officer. The Presiding Officer, for good cause shown, may extend the time for filing and may allow reply briefs.

exceptional circumstances, that to delay review would not be in the public interest. Such motion shall be made within 5 days after receipt of notification that the Presiding Officer has refused to certify a order or ruling for interlocutory appeal to the Administrator.

(e) The failure of a party to request an interlocutory appeal shall not prevent an appeal of an order or ruling as part of an appeal of a proposed decision under § 72.108.

§ 72.108 Appeal of proposed decisions to the administrator.

(a) Within 30 days after the issuance of a proposed decision by a Presiding Officer under this subpart, any party of record may appeal any matter set forth in the proposed decision or any other order or ruling made during the proceeding to which the party objected during the proceeding before the Presiding Officer, by filing an objection with the Administrator. In its objection, the party must show that the order, ruling, or proposed decision is based on:

(1) A finding of fact or conclusion of law that is clearly erroneous; or

(2) A policy determination or exercise of discretion that is arbitrary and capricious.

(b) Within 30 days after issuance of a proposed decision of a Presiding Officer, the Administrator may issue, sua sponte, in his or her discretion a notice of intent to review such proposed decision. The Administrator shall serve such notice upon all parties to the proceeding.

(c) Within a reasonable time following the filing of an appeal pursuant to § 72.92, objections under subsection (a), or of a notice of intent to review under subsection (b), the Administrator shall issue an order affirming, reversing, modifying, or remanding the permitting decision or proposed decision, as appropriate. Prior to issuing this order, the Administrator may provide an opportunity for parties to file additional briefs.

(d) If a party timely files objection to a proposed decision or permitting decision or if the Administrator, sua sponte, orders a review, then final Agency action shall occur as follows:

(1) If the Administrator issues a final order affirming, reversing, or modifying the permitting decision or proposed decision, the permitting decision or proposed decision, supplemented or changed by the final order, shall become the final Agency action;

(2) If the Administrator issues a decision remanding the proceeding, then final Agency action occurs upon completion of the remanded proceeding, including any appeals to the Administrator of the remanded proceeding.

(e) If no party of record files an appeal within 30 days after the Presiding Officer's proposed decision, and the Administrator does not decide to review the proposed order sua sponte, then the proposed decision shall become final Agency action.

Measures and implementation that would constitute such interference, and are thus prohibited, include but are not limited to:

(1) Prohibitions on the acquisition or transfer of allowances by an affected unit located in the State or area under the jurisdiction of the permitting authority inconsistent with Title IV;

(2) Restrictions on an affected unit's ability to sell or otherwise alienate its allowances inconsistent with Title IV;

(3) Requirements that an affected unit maintain a reserve of allowances in excess of the level determined to be prudent by the State regulatory authority or other entity having utility rate regulatory authority over the affected unit;

(4) Failing to notify the Administrator of any State-level appeals to, or decisions covering, Acid Rain permit provisions that might affect Acid Rain program requirements;

(5) The issuance of an order by the permitting authority inconsistent with Title IV interpreting Acid Rain program requirements as not applying to a source in whole or in part, or otherwise modifying the requirements;

(6) Withholding of approval of any compliance option that meets the requirements of Title IV; or

(7) Any other measure that the Administrator determines would hinder the operation of the Acid Rain program.

(b) *Excess Emissions Offset Plan.* The permitting authority shall not interfere with the Administrator's decision regarding an excess emissions offset plan. Such interference shall constitute grounds for the Administrator to withhold or withdraw approval of the permit program.

(c) *Acid Rain Permit Program Forms.* In developing the Acid Rain portion of the operating permit, the permitting authority shall use the Acid Rain program forms specified in Appendix C of this part and, if the permitting authority is participating in the Acid Rain Permit program Electronic Application and Reporting System, issue permits in accordance with such system. These forms include Acid Rain permit application forms, proposed compliance plan forms, Acid Rain permit forms, and Acid Rain compliance certification reporting forms.

(d) *Acid Rain Permit.*

(1) *Content.* (i) The permitting authority shall issue, as a stand alone subpart of each source's operating permit pursuant to 40 CFR Part 70, a proposed Acid Rain permit subpart that incorporates all the permit requirements of Subpart E of this part, including all monitoring requirements the standard Acid Rain permit provisions of Subpart E.

(ii) Such proposed Acid Rain permit subpart shall assure that the source is required to meet all of its obligations under Title IV of the Act and 40 CFR Parts 72-78.

(2) Each proposed Acid Rain permit subpart, including the approved compliance plan, shall contain all applicable Acid Rain requirements and prohibitions, shall be a complete and segregable

(5) *Proposed Permit.* Following the public notice and comment period on a draft Acid Rain permit, the permitting authority shall incorporate all changes necessary and develop a proposed Acid Rain permit that conforms to the applicable requirements of this subpart and Subpart E of this part.

(6) *Submittal to Administrator.* (i) The permitting authority shall submit the proposed Acid Rain permit to the Administrator in accordance with 40 CFR Part 70.

(ii) The Administrator shall review the proposed Acid Rain permit consistent with the requirements of 40 CFR 70.8(c).

(7) *Acid Rain Permit Issuance.* Following the Administrator's review of a proposed permit, the permitting authority or, under the terms of 40 CFR 70.8(c), the Administrator, shall incorporate any required changes and shall issue or deny the Acid Rain portion of the permit.

(8) *Effective Date of Acid Rain Permits.* Each source's Acid Rain permit issued by a permitting authority under this section shall be effective for a period of 5 years.

(9) *Designated Representative Requirements.* In no case shall a draft, proposed, or final Acid Rain permit be issued unless a representative has been designated pursuant to a complete certificate of representation, submitted in accordance with Subpart B of this part.

(10) Notwithstanding any State law providing that a permit must be issued by default after a specified time, no Acid Rain permit shall be issued until the Administrator and neighboring States have had an opportunity to review a proposed Acid Rain permit as provided in this section and in 40 CFR 70.8(e).

(11) The deadlines and requirements for a permitting authority to take action on an Acid Rain permit application during the transition between Phase I and Phase II of the Acid Rain program, are governed by this part and Title IV of the Act. At all other times, the permitting authority shall issue a permit within 6 months of receiving a complete application in accordance with 40 CFR 70.7(a)(2).

(f) *Permit Revisions.* In acting on any Acid Rain permit revision, the permitting authority shall follow the permit revisions procedures set forth at Subpart J of this part.

(g) *Permit Renewal.* (1) The renewal of an Acid Rain permit for an affected source shall be subject to all the requirements of this subpart pertaining to the issuance of permits.

(2) The Acid Rain permit renewal application and proposed compliance plan submitted in accordance with this part and Title IV of the Act shall be binding on the designated representative for the source and shall be enforceable as a permit in the event that an Acid Rain permit expires prior to renewal, upon a determination of completeness by the permitting authority.

(h) *New Owners.* Acid Rain permits shall be binding on any new owner or operator of a source by operation of law consistent with the requirements of Subpart B of this part.

(i) *Acid Rain Appeal Procedures.* (1)(i) Appeals of Acid Rain permitting provisions in permits issued by the State that are not

(b) *Sulfur Dioxide Applications and Compliance Plans.* The designated representative of any existing Phase II affected unit shall submit a complete sulfur dioxide permit application and proposed compliance plan for that unit to the permitting authority, and to the Administrator not later than January 1, 1996.

(c) *New Units.* For any new affected unit as specified in § 72.7 a complete Acid Rain permit application shall be submitted not later than 24 months before the later of:

(1) January 1, 2000; or

(2) The date on which the unit commences commercial operation.

(d) *Nitrogen Oxides Applications and Compliance Plans.* The designated representative of any Phase II affected unit subject to an emissions limitation requirement for nitrogen oxides under Section 407 of the Act and 40 CFR Part 76, shall submit a complete permit application and proposed compliance plan for such unit to the permitting authority and to the Administrator, not later than January 1, 1998 or for new units, not later than 24 months before the date on which the unit commences operation. The permitting authority shall issue a permit to the affected source that satisfies the requirements of Title V and this title, including any appropriate monitoring and reporting requirements.

§ 72.204 State issuance of phase II permits.

(a) *State Permit Issuance.* (1) States with operating permit programs pursuant to 40 CFR Part 70 and this part that have been approved by the Administrator on or before July 1, 1996, shall be responsible for issuing Phase II permits to all Phase II affected units in that State.

(2) States that have obtained interim operating permit program approval (as defined in 40 CFR 70.4(d)) on or before July 1, 1996, shall issue permits in accordance with the requirements of this part, and 40 CFR Part 70 and 40 CFR Parts 73-78 to all Phase II affected units in that State.

(3) States that have obtained partial operating permit program approval (as defined in 40 CFR 70.4(c)) on or before July 1, 1996, shall issue permits in accordance with the requirements of this part and 40 CFR Part 70 and 40 CFR Parts 73-78 to all Phase II affected units that are required to obtain a permit as a result of the partial approval.

(4) *Permit Issuance.* The permitting authority shall follow all applicable permit issuance procedures specified in 40 CFR Part 70 and of this subpart.

(5) *Permit Content.* (i) The Acid Rain portion of the permit issued to the source under 40 CFR Part 70 shall contain all the applicable requirements specified in Subpart E, including the standard Acid Rain permit provisions specified in § 72.54.

(ii) Each permit shall specify the basic and bonus allowance allocations for each affected unit at the source as specified in 40 CFR Part 73.

State which, on July 1, 1996, did not have an approved program under 40 CFR Part 70; *provided* that the designated representative for the affected source submitted a timely and complete Acid Rain permit application to the Administrator pursuant to Subpart C. A failure by the Administrator to issue a Phase II permit in accordance with this paragraph shall be grounds for the filing of an appeal as provided in Subpart H.

(ii) Notwithstanding paragraph (b)(1)(i) of this section the Administrator may delegate to any State that obtains operating permit program approval after July 1, 1996, the responsibility for permit review and implementation.

(iii) Each Phase II permit issued by the Administrator pursuant to this section shall have a term of 5 years. Prior to the effective date of the Acid Rain portion of the permit, the affected source shall be bound by the terms of the complete permit application and approved compliance plan as modified or conditioned by the Administrator when issuing the permit.

(2) *Nitrogen Oxides.* (i) Phase II Acid Rain permits issued by the Administrator pursuant to paragraph (b)(1) of this section may, but are not required to, include Acid Rain nitrogen oxides requirements.

(ii) Notwithstanding paragraph (b)(2)(i) of this section, not later than 6 months following submission by the designated representative of an affected unit of a complete and timely Acid Rain nitrogen oxides permit application and proposed compliance plan in accordance with Subpart C, the Administrator shall reopen the Acid Rain portion of the permit issued pursuant to paragraph (1) of this section to add the Acid Rain nitrogen oxides requirements pursuant to this part, 40 CFR Part 71, and 40 CFR Parts 75-78.

(iii) The reopening of a permit for the purposes of adding the Acid Rain nitrogen oxides requirements shall not alter or affect the term of the permit, which shall continue to be effective for a term of 5 years.

(c) *Permit Issuance.* In taking permit action under this section, the Administrator shall issue Phase II permits in accordance with Subpart G of this part and 40 CFR Part 71.

(d) *Permit Content.* (1) Permits issued under this section shall contain all applicable requirements specified in Subpart E, including the standard Acid Rain permit provisions specified in § 72.54.

(2) Permits issued under this section shall specify the basic allowance allocation for the unit specified in 40 CFR Part 73.

Subpart J—Permit Revisions

§ 72.300 General.

(a) This subpart shall govern revisions to any Federally issued Acid Rain permit, and to the Acid Rain portion of any operating

§ 72.302 Fast-track modifications.

Option 1

(a)(1) Upon the consent of the permittee, the permitting authority may modify a permit using the procedures of this section to incorporate a new optional method of compliance (except that incorporation of a new reduced utilization plan that does not name a compensating unit may be done using the administrative permit amendment procedure pursuant to § 72.303 in lieu of this procedure) without following the permit modification procedures set forth in § 72.301. This procedure may also be used for a change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program, or for changes to a Phase I extension plan, repowering plan, nitrogen oxides averaging plan, nitrogen oxides alternative emissions plan, or nitrogen oxides compliance deadline extension plan.

(2) In lieu of this procedure, the permit modification procedure may be used to effect these changes. The administrative amendment procedure pursuant to § 72.303 and the minor permit amendment procedure pursuant to 40 CFR Part 70 shall not be used for the permit revisions listed in paragraph (a)(1) above.

(b) *Procedure.* The following procedures shall apply to all fast-track modifications.

(1) The designated representative shall submit to the permitting authority a complete compliance plan form for the new optional method of compliance that the designated representative proposes to use.

(2) The permitting authority shall approve or disapprove the application within 30 days following receipt of a complete compliance plan. Disapproval of the compliance plan shall be considered a permitting decision for purposes of administrative review.

(3) If the permitting authority proposes to approve the new method of compliance, notification of the proposed modification shall be sent to all persons who commented during the public comment period on the permit for the source proposed to be modified. For substitution plans and nitrogen oxides emissions averaging plans, notice shall also be published in a newspaper of general circulation in the area affected by the source or unit proposed to be newly affected under the substitution or averaging plan.

(4) Persons who receive notice have 15 days in which to object to the proposed modification.

(5) If no significant objections are received, the proposed modification shall take effect at the end of the 15-day comment period.

(6) If significant objections to the proposed modification are received within 15 days, the proposed modification shall follow

§ 72.303 Administrative permit amendment.

(a) Acid Rain permit revisions that use the administrative permit amendment procedures shall include, but are not limited to:

(1) Activation of a compliance plan option approved in the initial permit decision, provided the option is activated within the time specified by the permit pursuant to this part;

(2) Change in the designated representative, provided that a new certificate of representation is submitted;

(3) Correction of typographical errors;

(4) Increases in monitoring frequency;

(5) Changes in names, addresses or phone numbers;

(6) Changes in ownership or operation control, provided that a new certificate of representation is submitted within 30 days;

(7) Inclusion of an excess emissions offset plan that has been approved by the Administrator pursuant to 40 CFR Part 77.

(8) Incorporation of a reduced utilization plan that does not name or change requirements applicable to a compensating unit, provided that such plan meets all applicable requirements of § 72.43;

(9) Termination of a compliance option in the permit that does not involve de-designating a unit; except that this procedure shall not be used for termination of a Phase I extension plan; nor shall it be used to terminate a repowering plan after December 31, 1999;

(10) Changes in a substitution or reduced utilization plan that do not result in a previously unaffected unit becoming affected under the Acid Rain program; and

(11) De-designation of a substitution unit or compensating unit, provided that the unit complies with the requirements of § 72.41(c)(2) for substitution units, and § 72.43(b)(2) for compensating units.

(b) Administrative amendments of Acid Rain permits shall follow the procedures set forth at 40 CFR 70.7(e).

(c) Actual notice of administrative amendments to Acid Rain permits shall be given to all interested persons by the source. A certification that such notice was given shall be submitted to the permitting authority by the designated representative for the source.

§ 72.304 Automatic permit amendment.

Pursuant to 40 CFR Part 73, all allowance allocations to, acquisitions for, and transfers to or from, an affected unit's Allowance Tracking System account shall, upon recordation by the Administrator, be deemed to automatically amend and become a part of the affected unit's permit by operation of law without any further permit review or revision. Such allocations and transfers shall be governed by 40 CFR Part 73.

§ 72.401 Quarterly reports.

(a) The designated representative of each affected unit shall submit the following compliance certifications for the unit on a quarterly basis:

(1) Certified emissions data and quality assurance information as required by 40 CFR Part 75.

(2) Certification of the unit's compliance status with regard to any scheduled deadline or increment of progress specified in the permit occurring during the prior calendar quarter.

(b) Quarterly monitoring reports for the first three calendar quarters of each year shall be postmarked not later than 30 days following the last day of each calendar quarter (April 30, July 30, October 30). The quarterly report for the fourth calendar quarter of each year, shall be submitted concurrently with the unit's annual report.

§ 72.402 Annual reports.

The designated representative of each affected unit shall submit the following compliance certifications for the unit annually, not later than the allowance transfer deadline established pursuant to 40 CFR Part 73:

(a) A general certification, using SF# 72402 in Appendix C of this part, as follows:

(1) Identification of the affected unit;

(2) The compliance plan option(s) that apply to this unit; and

(3) Designated representative identification.

(b) Certification of the unit's compliance status with regard to whether the annual sulfur dioxide emissions from the affected unit did or did not exceed the allowances held as of the allowance transfer deadline in the unit's Allowance Tracking System compliance subaccount. The certification shall include the following information:

(1) The total tons of sulfur dioxide emitted for the calendar year by the affected unit;

(2) The number of allowances held as of the allowance transfer deadline in the affected unit's compliance subaccount; and

(3) The baseline and actual annual heat input (in mmBtu) and generation (in Kwh) for the calendar year for the affected unit.

(c) If the affected unit's actual heat input, reported in accordance with paragraph (b)(3) of this section, is less than the unit's baseline the designated representative shall include in the annual report one or more of the following demonstrations for the unit:

(1) That the utilization below baseline was due in whole or in part to either:

(i) Dispatching between Phase I units in the unit's utility system, and is accounted for by net aggregate utilization of Phase I affected units' in the utility system of which the unit is a part above the utility system's Phase I units' aggregate

(1) The applicable emissions limitation for the unit;
(2) The total tons of emissions for the year; and
(3) The extent of any exceedance.

§ 72.403 Other.

The designated representative of each affected unit shall submit the following compliance certifications to the Administrator and the permitting authority for the unit:

(a) Notice 60 days prior to any proposed revision in a scheduled increment of progress specified in the permit, including:

(1) A change in the date for taking a unit out of operation to repower under § 72.44(e)(1)(iv),

(2) A change in any scheduled date leading to and including the start-up of a new unit as specified in § 72.45(d)(2),

(3) A change in any scheduled date in the installation and start-up schedule for 90% control technology at a Phase I Extension unit as specified in § 72.42(e)(2)(i)(B)*(4)*,

(4) A change in the date for the start-up performance test for the qualifying Phase I technology as specified in § 72.42(e)(2)(i)(D)*(1)*,

(5) A change in the date for an annual performance test for the qualifying Phase I technology as specified in § 72.42(e)(2)(i)(D)*(2)*, and

(6) A change in the scheduled increment of progress in an excess emissions offset plan pursuant to 40 CFR 77.2(e)(5)(vii).

(b) Notice 10 days after any deviation from any applicable compliance plan requirement, including:

(1) Failure to meet any of the dates scheduled or revised pursuant to subsection (a) of this section,

(2) Failure to make the required submission under a repowering plan by the deadline specified in § 72.44(e)(1)(v),

(3) Failure to submit an application for a final nitrogen oxides alternative emissions limitation by the deadline specified in § 72.47(d)(2)

(c) Notice within 10 days following any nonscheduled event that affects the sources ability to comply with any applicable requirement of this part and 40 CFR Parts 73-78, including:

(1) A forced outage,

(2) A sudden unavailability of the designated representative (including any alternate designated representative).

§ 72.404 Certification statement.

(a) All compliance certifications required by this part shall include the certification of truth and accuracy by the designated representative specified in § 72.9(a)(2).

(b) Compliance certifications shall include all other information required by the Administrator in accordance with this part.

§ 72.409 Accounting for phase I shifts in utilization.

(a) *Compliance Certification Reporting.* In accordance with § 72.402(b)(4)(ii), the designated representative for any Phase I affected unit with under-utilization not accounted for by a reduced utilization compliance plan approved pursuant to § 72.43 shall submit one or more of the following with the unit's annual report:

(1) A demonstration that the under-utilization at the Phase I affected unit below its baseline was due, in whole or in part, to shifts of generation to other Phase I affected units in the same system, calculated as provided in subsection (b), below;

(2) A demonstration that the under-utilization at the affected unit was due, in whole or in part, to a system-wide decrease in electrical demand, calculated as provided in subsection (c), below;

(3) A demonstration that the under-utilization at the Phase I affected unit was below its baseline due in whole or in part to a forced outage, as provided in subsection (d), below; or

(4) The submission required by subsection (e) of this section.

(b) To demonstrate that the unplanned under-utilization at the affected unit below its baseline was due, in whole or in part, to shifts of generation from the unit to other Phase I affected units, the unit shall use the following calculation:

(1) Calculate the aggregate utilization (in mmBtu and Kwh) of all Phase I affected units within the utility system identified in the permit application in accordance with § 72.31(a)(5);

(2) Compare the calculation of paragraph (1), to the aggregate baseline of all Phase I affected units within the system;

(3) If paragraph (1) is greater than or equal to the aggregate baseline of all affected units within a system, calculated pursuant to paragraph (2), no further demonstration is necessary. If not go on to the next demonstration.

(c) To demonstrate that unplanned under-utilization at a Phase I affected unit below its baseline was due, in whole or in part, to a system-wide decrease in sales, the unit shall use the following calculation:

(1) Calculate the percentage decline of aggregate annual kilowatt hour sales for the utility system, as identified in the permit application in accordance with § 72.31(a)(5), compared to system sales during the preceding calendar year;

(2) Calculate the decline in utilization of the Phase I unit (in mmBtu, Kwh, and percentage) as compared to baseline;

(3) If paragraph (1) is greater than or equal to the actual reduced utilization at the Phase I unit, calculated pursuant to paragraph (2), no further demonstration is necessary. If not go on to the next demonstration.

(d) *Forced Outages.* (1) In addition to the other requirements in this section, where a forced outage has led to unplanned reduced utilization at a Phase I affected unit, the designated representative shall provide the Administrator with the following information, using SF# 72409A in Appendix C of this part:

utilization below baseline not accounted for under an approved reduced utilization plan for all affected units within the system;

C is the utilization below baseline for the individual affected unit for which the calculation is being made (in mmBtu);

D is the Btu-weighted average annual emissions rate for the previous calendar year for (1) all units in the NERC region where the under-utilized unit is located, (2) for all units within the utility system and units outside of the utility system that have been specifically identified, or (3) a combination of (1) and (2), calculated in accordance with paragraph (2), below;

E is the aggregate under-utilization at all Phase I units in the utility system below their aggregate baseline that is attributable to the system-wide percentage decline in utilization, as calculated pursuant to § 72.409(b)(1); and

F is the percentage of the total annual Btu's above baseline that is attributable to Phase I units outside of the utility system located in the NERC region where the unit that experienced the under-utilization is located, multiplied by the percentage of the utility's generation for which the NERC region average emissions rate will be used in paragraph (2), below (i.e., 100% in paragraph (2)(ii) and a in paragraph (2)(iii)).

(2) *Formula for Calculating Average Emissions Rate.* The Btu-weighted average annual emissions rate for the previous year (D in subparagraph (e)(1), above) according to one of the following options:

(i) Based on the weighted-average emissions rate of all units within the NERC region where the unit that experienced under-utilization is located, as set forth below:

$$D = \frac{\sum_{i=1}^{n} (c_i \times d_i)}{\sum_{i=1}^{n} c_i}$$

where:

c_i is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu).

$$D = a \times \frac{\sum_{i=1}^{n} (c_i \times d_i)}{\sum_{i=1}^{n} c_i} + b \times \frac{\sum_{i=1}^{m} (e_i \times f_i)}{\sum_{i=1}^{m} e_i}$$

where:

a is the % of compensating generation from units outside of the utility system that have not been specifically identified, for which the NERC region average emissions rate will be used.

b is the % of compensating generation from (1) units within the utility system and (2) units outside the utility system that have been specifically identified.

c_i is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu).

d_i is the average annual emissions rate for each unit within the NERC region (in lbs/mmBtu).

e_i is the difference between the annual heat input for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu) and the baseline for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu)

f_i is the average annual emissions rate for each unit within the utility system and each specifically identified unit outside of the utility system.

n is the number of units in the NERC region.

m is the number of units within the utility system and specifically identified units outside the utility system providing compensating generation.

(f) *Action of Administrator.* Where a shift in generation from an affected unit to a non-affected unit has resulted in unplanned under-utilization at a Phase I affected unit as provided in this section, the Administrator shall deduct allowances from the compliance subaccount according to the formulas in subsection (e) of this section and 40 CFR 73.35.

(b) The Administrator will issue to any person submitting a certificate of representation pursuant to Subpart B and subsection (a), above, a secure DR PIN # within 30 days of receipt of the certificate of representation, and shall provide the designated representative notice of the procedures to be followed for participation in the phone queuing, and of follow-up procedures for the processing of Phase I Extension Early Ranking applications, as provided in subsections (c) and (d), below.

(c) *Phone Queuing Procedure.* (1) Beginning not earlier than 8:00 a.m. EST on the date specified in the notice issued under subsection (b), the designated representative for any unit electing to participate in the Phase I Extension Early Ranking procedure of this subpart shall call the telephone number obtained by the applicant by following the procedures specified in the notice issued under subsection (b).

(2) Upon being connected to the Early Ranking voice-mail system and upon receiving recorded instructions, the designated representative shall enter a secure application identification number, registered through the procedures specified in the notice issued under subsection (b), and the DR PIN # obtained in the notice issued under subsection (b).

(3) As instructed by the Early Ranking voice-mail system the designated representative shall, thereafter, register by voice mail the unit or units applying for the Phase I Extension Early Ranking.

(d) *Written Phase I Extension Early Ranking Application.*

(1) Not later than midnight of the same business day an Early Ranking application is registered pursuant to the phone queuing procedure in subsection (c), the designated representative shall submit a complete written Phase I Extension Early Ranking application to the Administrator, in accordance with paragraphs (2)-(4), below. This written submission, if timely made, shall perfect the Early Ranking application's order of receipt.

(2) *Contents of Phase I Extension Ranking Application.* The designated representative for each affected unit seeking a Phase I Extension under § 72.42 who participated in the phone queuing procedure of subsection (c), shall submit to the Administrator a complete Phase I Extension Ranking Application by the deadline specified in paragraph (1), using SF# 7242 in Appendix C of this part. The ranking application shall contain all of the information required in § 72.42(e)(1), (e)(2)(i), (e)(2)(ii)(**A**)*(1)* and (e)(2)(ii)(B), as well as the provisions of § 72.500(**b**).

(3) Phase I Extension Early Ranking Applications shall be submitted by certified mail to the following address:

Chief, Permits and Technologies Section
U.S. Environmental Protection Agency
OAR/OAIAP/Acid Rain Division (ANR-445)
401 M. Street, S.W.
Washington, D.C. 20460

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS

Table A
Allowance Allocations

State	Plant Name	Unit	88 SO_2 (TPY)	89 SO_2 (TPY)
AL	COLBERT	1	20,886	20,609
AL	COLBERT	2	28,052	22,237
AL	COLBERT	3	24,397	21,985
AL	COLBERT	4	24,626	18,537
AL	COLBERT	5	41,847	51,952
AL	E C GASTON	1	19,348	23,747
AL	E C GASTON	2	19,023	20,363
AL	E C GASTON	3	17,205	21,466
AL	E C GASTON	4	15,715	23,620
AL	E C GASTON	5	47,526	68,507
FL	BIG BEND	BB01	59,686	51,720
FL	BIG BEND	BB02	48,835	44,129
FL	BIG BEND	BB03	43,973	55,968
FL	CRIST	6	39,985	38,655
FL	CRIST	7	64,162	60,152
GA	BOWEN	1BLR	53,893	46,093
GA	BOWEN	2BLR	62,029	48,498
GA	BOWEN	3BLR	81,636	61,074
GA	BOWEN	4BLR	74,841	66,606
GA	HAMMOND	1	9,674	10,816
GA	HAMMOND	2	9,410	8,576
GA	HAMMOND	3	9,718	9,583
GA	HAMMOND	4	44,934	43,322
GA	JACK MCDONOUGH	MB1	35,734	31,904
GA	JACK MCDONOUGH	MB2	36,502	30,222
GA	WANSLEY	1	117,893	110,787
GA	WANSLEY	2	117,996	111,979
GA	YATES	Y1BR	7,405	8,694
GA	YATES	Y2BR	7,562	5,488
GA	YATES	Y3BR	5,839	6,500
GA	YATES	Y4BR	8,911	7,721
GA	YATES	Y5BR	8,587	8,503
GA	YATES	Y6BR	28,435	30,326
GA	YATES	Y7BR	27,564	24,968
IL	BALDWIN	1	80,577	85,289
IL	BALDWIN	2	82,081	89,755
IL	BALDWIN	3	85,204	58,167
IL	COFFEEN	01	32,999	22,034
IL	COFFEEN	02	83,027	108,867
IL	GRAND TOWER	9	11,763	6,916
IL	HENNEPIN	2	28,552	28,097
IL	JOPPA STEAM	1	13,848	18,336
IL	JOPPA STEAM	2	11,282	18,021
IL	JOPPA STEAM	3	15,597	14,537
IL	JOPPA STEAM	4	15,018	16,813
IL	JOPPA STEAM	5	14,866	15,814
IL	JOPPA STEAM	6	12,913	18,944
IL	KINCAID	1	65,350	77,199
IL	KINCAID	2	93,779	67,506
IL	MEREDOSIA	03	1,240	896
IL	VERMILION	2	13,445	12,625

Table A
Allowance Allocations

State	Plant Name	Unit	88 SO_2 (TPY)	89 SO_2 (TPY)
KY	ELMER SMITH	2	21,034	26,870
KY	GHENT	2	12,814	7,300
KY	GREEN RIVER	5	15,082	16,519
KY	H L SPURLOCK	1	31,048	21,226
KY	HMP&L STATION 2	H1	18,841	20,958
KY	HMP&L STATION 2	H2	24,158	17,764
KY	PARADISE	3	162,748	127,854
KY	SHAWNEE	10	513	11,413
MD	CHALK POINT	1	28,052	23,897
MD	CHALK POINT	2	22,105	26,681
MD	C P CRANE	1	14,488	11,084
MD	C P CRANE	2	12,285	12,482
MD	MORGANTOWN	1	49,252	42,429
MD	MORGANTOWN	2	40,338	52,989
MI	J H CAMPBELL	1	10,775	9,658
MI	J H CAMPBELL	2	13,239	13,114
MN	HIGH BRIDGE	12	1,447	1,763
MS	JACK WATSON	4	30,444	31,973
MS	JACK WATSON	5	58,796	46,093
MO	ASBURY	1	63,339	67,438
MO	JAMES RIVER	5	12,663	9,479
MO	LABADIE	1	70,676	50,984
MO	LABADIE	2	67,443	61,755
MO	LABADIE	3	58,701	67,296
MO	LABADIE	4	58,347	70,025
MO	MONTROSE	1	1,841	2,345
MO	MONTROSE	2	2,768	1,625
MO	MONTROSE	3	2,814	2,825
MO	NEW MADRID	1	69,751	82,419
MO	NEW MADRID	2	53,418	94,083
MO	SIBLEY	3	45,718	36,140
MO	SIOUX	1	32,865	45,148
MO	SIOUX	2	38,722	35,448
MO	THOMAS HILL	MB1	37,430	35,497
MO	THOMAS HILL	MB2	56,310	48,995
NH	MERRIMACK	1	13,675	11,461
NH	MERRIMACK	2	37,362	34,521
NJ	B L ENGLAND	1	15,509	13,730
NJ	B L ENGLAND	2	18,181	19,185
NY	DUNKIRK	3	20,297	15,292
NY	DUNKIRK	4	15,605	21,939
NY	GREENIDGE	6	12,677	11,364
NY	MILLIKEN	1	15,535	13,835
NY	MILLIKEN	2	13,233	14,636
NY	NORTHPORT	1	11,579	11,267
NY	NORTHPORT	2	10,736	9,551
NY	NORTHPORT	3	11,872	10,817
NY	PORT JEFFERSON	3	5,521	5,686
NY	PORT JEFFERSON	4	4,564	5,315

Table A
Allowance
Allocations

State	Plant Name	Unit	(Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
PA	PORTLAND	1		7,928	10,897
PA	PORTLAND	2		20,206	15,037
PA	SHAWVILLE	1		13,002	14,306
PA	SHAWVILLE	2		14,249	12,098
PA	SHAWVILLE	3		17,864	16,540
PA	SHAWVILLE	4		14,579	18,212
PA	SUNBURY	4		16,908	18,941
PA	SUNBURY	1A		6,223	6,173
PA	SUNBURY	1B		6,223	6,173
PA	SUNBURY	2A		6,223	6,173
PA	SUNBURY	2B		6,223	6,173
TN	ALLEN	1		17,696	28,128
TN	ALLEN	2		21,677	16,446
TN	ALLEN	3		24,950	10,638
TN	CUMBERLAND	1		204,677	130,043
TN	CUMBERLAND	2		152,954	196,954
TN	GALLATIN	1		29,240	35,686
TN	GALLATIN	2		36,839	27,435
TN	GALLATIN	3		38,400	35,037
TN	GALLATIN	4		43,128	25,763
TN	JOHNSONVILLE	1		12,377	9,750
TN	JOHNSONVILLE	2		12,806	8,313
TN	JOHNSONVILLE	3		11,749	8,759
TN	JOHNSONVILLE	4		7,456	4,003
TN	JOHNSONVILLE	5		7,146	9,302
TN	JOHNSONVILLE	6		980	9,261
TN	JOHNSONVILLE	7		11,816	4,704
TN	JOHNSONVILLE	8		11,525	9,338
TN	JOHNSONVILLE	9		10,607	4,385
TN	JOHNSONVILLE	10		8,124	3,639
WV	ALBRIGHT	3		14,035	7,034
WV	FORT MARTIN	1		43,036	53,250
WV	FORT MARTIN	2		49,790	40,615
WV	HARRISON	1		88,364	79,416
WV	HARRISON	2		86,228	98,561
WV	HARRISON	3		89,544	94,101
WV	KAMMER	1		48,352	49,606
WV	KAMMER	2		52,771	49,147
WV	KAMMER	3		47,892	54,310
WV	MITCHELL	1		31,298	36,753
WV	MITCHELL	2		43,592	30,010
WV	MT STORM	1		45,915	55,258
WV	MT STORM	2		53,517	49,715
WV	MT STORM	3		48,120	53,827
WI	EDGEWATER	4		37,340	42,233
WI	LA CROSSE/GENOA	3		-	-
WI	NELSON DEWEY	1		6,535	7,045
WI	NELSON DEWEY	2		5,137	4,311
WI	NORTH OAK CREEK	1		3,645	3,191
WI	NORTH OAK CREEK	2		3,949	1,770
WI	NORTH OAK CREEK	3		0	-
WI	NORTH OAK CREEK	4		0	-
WI	PULLIAM	8		15,154	11,270
WI	SOUTH OAK CREEK	5		14,720	6,954

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
AZ	IRVINGTON	1		0	0
AZ	IRVINGTON	3		0	0
AZ	IRVINGTON	2		0	0
AZ	KYRENE	K-1		0	9
AZ	KYRENE	K-2		9	12
AZ	NAVAJO	2		21,473	26,110
AZ	NAVAJO	1		24,588	25,004
AZ	NAVAJO	3		24,441	21,961
AZ	OCOTILLO	2		0	5
AZ	OCOTILLO	1		0	23
AZ	SAGUARO	2		-	0
AZ	SAGUARO	1		-	0
AZ	SPRINGERVILLE	1		7,239	8,457
AZ	SPRINGERVILLE	2		0	0
AZ	WEST PHOENIX	4		-	0
AZ	WEST PHOENIX	5		-	0
AZ	WEST PHOENIX	6		-	1
AZ	YUMA AXIS	1		0	0
AR	FLINT CREEK	1		11,036	10,050
AR	HARVEY COUCH	1		0	0
AR	HARVEY COUCH	2		76	0
AR	INDEPENDENCE	1		9,734	7,199
AR	INDEPENDENCE	2		8,660	10,506
AR	LAKE CATHERINE	2		0	0
AR	LAKE CATHERINE	4		0	237
AR	LAKE CATHERINE	3		0	0
AR	LAKE CATHERINE	1		0	0
AR	ROBERT E RITCHIE	2		0	175
AR	ROBERT E RITCHIE	1		256	59
AR	WHITE BLUFF	2		20,959	19,242
AR	WHITE BLUFF	1		21,364	19,190
CA	ALAMITOS	2		11	27
CA	ALAMITOS	3		0	0
CA	ALAMITOS	1		0	60
CA	ALAMITOS	6		164	400
CA	ALAMITOS	5		389	217
CA	ALAMITOS	4		227	194
CA	BROADWAY	B3		31	12
CA	BROADWAY	B2		21	22
CA	BROADWAY	B1		16	8
CA	CONTRA COSTA	5		0	0
CA	CONTRA COSTA	4		0	0
CA	CONTRA COSTA	6		0	0
CA	CONTRA COSTA	7		0	0
CA	CONTRA COSTA	8		0	0
CA	CONTRA COSTA	3		0	0
CA	CONTRA COSTA	2		0	0
CA	CONTRA COSTA	9		19	0
CA	CONTRA COSTA	1		0	0
CA	CONTRA COSTA	10		192	882
CA	COOL WATER	2		0	2
CA	COOL WATER	1		1	3
CA	EL SEGUNDO	3		6	165
CA	EL SEGUNDO	1		64	111
CA	EL SEGUNDO	2		34	25

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
CA	MOSS LANDING	6-1		1,887	1,707
CA	MOSS LANDING	6		0	0
CA	MOSS LANDING	5		0	0
CA	MOSS LANDING	4		0	0
CA	OLIVE	01		0	5
CA	OLIVE	02		4	47
CA	ORMOND BEACH	1		109	379
CA	ORMOND BEACH	2		476	433
CA	PITTSBURG	6		964	988
CA	PITTSBURG	7		0	16
CA	PITTSBURG	3		213	88
CA	PITTSBURG	1		105	167
CA	PITTSBURG	4		165	161
CA	PITTSBURG	5		628	486
CA	PITTSBURG	2		169	149
CA	POTRERO	3-1		694	431
CA	REDONDO BEACH	17		0	0
CA	REDONDO BEACH	16		0	0
CA	REDONDO BEACH	5		0	7
CA	REDONDO BEACH	6		16	7
CA	REDONDO BEACH	7		0	24
CA	REDONDO BEACH	15		0	0
CA	REDONDO BEACH	14		0	0
CA	REDONDO BEACH	11		0	0
CA	REDONDO BEACH	8		0	27
CA	REDONDO BEACH	12		0	0
CA	REDONDO BEACH	13		0	0
CA	SAN BERNARDINO	1		0	2
CA	SAN BERNARDINO	2		0	2
CA	SCATTERGOOD	1		134	115
CA	SCATTERGOOD	2		135	115
CA	SCATTERGOOD	3		0	0
CA	SOUTH BAY	3		83	176
CA	SOUTH BAY	4		18	48
CA	SOUTH BAY	1		415	292
CA	SOUTH BAY	2		291	189
CA	VALLEY	4		60	100
CA	VALLEY	3		53	12
CA	VALLEY	2		0	37
CA	VALLEY	1		0	16
CO	ARAPAHOE	4		1,746	2,431
CO	ARAPAHOE	3		389	687
CO	ARAPAHOE	1		190	590
CO	ARAPAHOE	2		207	722
CO	CAMEO	2		1,196	849
CO	CAMEO	1		536	566
CO	CHEROKEE	4		5,624	5,029
CO	CHEROKEE	1		133	2,414
CO	CHEROKEE	2		1,650	1,790
CO	CHEROKEE	3		3,558	2,909
CO	COMANCHE	2		6,828	5,865
CO	COMANCHE	1		6,164	6,467
CO	CRAIG	C3		10,544	3,188
CO	CRAIG	C1		9,765	11,500
CO	CRAIG	C2		10,496	10,274
CO	HAYDEN	H1		4,122	5,729

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
FL	ANCLOTE	1		5,049	11,222
FL	ANCLOTE	2		8,337	11,009
FL	ARVAH B HOPKINS	1		13	108
FL	ARVAH BHOPKINS	2		1,224	171
FL	BIG BEND	BB04		8,731	8,623
FL	C D MCINTOSH JR	3		10,457	12,089
FL	C D MCINTOSH JR	1		1,822	1,034
FL	C D MCINTOSH JR	2		214	113
FL	CAPE CANAVERAL	PCC2		2,829	3,657
FL	CAPE CANAVERAL	PCC1		3,059	2,678
FL	CRIST	3		0	0
FL	CRIST	4		8,619	11,033
FL	CRIST	1		0	0
FL	CRIST	2		0	0
FL	CRIST	5		11,836	8,053
FL	CRYSTAL RIVER	2		21,957	21,622
FL	CRYSTAL RIVER	5		25,389	24,817
FL	CRYSTAL RIVER	4		24,729	25,105
FL	CRYSTAL RIVER	1		22,447	17,497
FL	CUTLER	PCU5		0	0
FL	CUTLER	PCU6		0	0
FL	DEERHAVEN	B1		15	72
FL	DEERHAVEN	B2		7,918	7,089
FL	F J GANNON	GB04		9,170	7,720
FL	F J GANNON	GB05		10,780	13,042
FL	F J GANNON	GB03		7,271	8,120
FL	F J GANNON	GB06		17,884	14,034
FL	F J GANNON	GB02		5,729	6,412
FL	F J GANNON	GB01		5,948	4,569
FL	FORT MYERS	PFM2		9,680	9,139
FL	FORT MYERS	PFM1		2,147	1,891
FL	G E TURNER	2		0	0
FL	G E TURNER	4		1,311	2,416
FL	G E TURNER	3		1,076	2,625
FL	HENRY D KING	7		0	0
FL	HENRY D KING	8		0	18
FL	HIGGINS	1		904	1,552
FL	HIGGINS	2		959	1,930
FL	HIGGINS	3		909	1,931
FL	INDIAN RIVER	2		1,638	1,134
FL	INDIAN RIVER	1		418	420
FL	INDIAN RIVER	3		592	1,137
FL	J D KENNEDY	8		0	0
FL	J D KENNEDY	9		15	17
FL	J D KENNEDY	10		0	154
FL	J R KELLY	JRK8		8	19
FL	LARSEN MEMORIAL	7		84	94
FL	LAUDERDALE	PFL5		296	263
FL	LAUDERDALE	PFL4		263	500
FL	MANATEE	PMT1		10,187	12,133
FL	MANATEE	PMT2		13,957	12,156
FL	MARTIN	PMR2		4,340	2,471
FL	MARTIN	PMR1		2,939	3,057
FL	NORTHSIDE	2		0	0
FL	NORTHSIDE	3		14,736	8,370
FL	NORTHSIDE	1		9,751	3,289
FL	P L BARTOW	3		8,322	12,337

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
GA	PORT WENTWORTH	3		4,412	4,337
GA	PORT WENTWORTH	1		2,220	3,086
GA	PORT WENTWORTH	2		1,684	2,518
GA	PORT WENTWORTH	4		642	39
GA	RIVERSIDE	11		0	0
GA	RIVERSIDE	10		0	0
GA	RIVERSIDE	12		0	0
GA	SCHERER	4		0	7,294
GA	SCHERER	3		10,327	5,421
GA	SCHERER	2		8,329	4,392
GA	SCHERER	1		6,351	6,882
IL	COLLINS	2		555	490
IL	COLLINS	5		465	717
IL	COLLINS	1		1,063	389
IL	COLLINS	3		1,259	642
IL	COLLINS	4		781	368
IL	CRAWFORD	8		1,928	1,108
IL	CRAWFORD	7		931	608
IL	DALLMAN	31		8,808	12,615
IL	DALLMAN	32		10,952	10,452
IL	DALLMAN	33		5,915	5,627
IL	DUCK CREEK	1		11,640	11,618
IL	E D EDWARDS	1		3,430	3,350
IL	E D EDWARDS	3		11,949	9,522
IL	E D EDWARDS	2		8,555	10,661
IL	FISK	19		1,389	1,565
IL	GRAND TOWER	07		533	1,479
IL	GRAND TOWER	08		515	1,482
IL	GRAND TOWER	09		11,763	6,916
IL	HAVANA	6		53	146
IL	HAVANA	7		53	88
IL	HAVANA	9		6,336	8,735
IL	HAVANA	5		53	45
IL	HAVANA	8		53	128
IL	HAVANA	4		53	37
IL	HAVANA	1		53	20
IL	HAVANA	2		53	26
IL	HAVANA	3		53	27
IL	HENNEPIN	1		7,067	8,260
IL	HUTSONVILLE	06		5,774	3,927
IL	HUTSONVILLE	05		6,556	4,940
IL	JOILET 9	5		4,529	2,341
IL	JOLIET 29	82		2,838	2,268
IL	JOLIET 29	81		2,693	2,605
IL	JOLIET 29	71		2,873	3,224
IL	JOLIET 29	72		3,017	3,303
IL	LAKESIDE	8		2,118	1,859
IL	LAKESIDE	7		1,830	891
IL	MARION	4		6,773	5,846
IL	MARION	1		603	2,445
IL	MARION	3		1,386	2,346
IL	MARION	2		1,642	2,038
IL	MEREDOSIA	01		1,510	765
IL	MEREDOSIA	02		1,038	1,017
IL	MEREDOSIA	04		1,057	892
IL	MEREDOSIA	06		89	37

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
IN	PETERSBURG	3		17,960	17,681
IN	R M SCHAHFER	15		2,580	13,389
IN	R M SCHAHFER	17		4,453	5,877
IN	R M SCHAHFER	18		4,976	5,673
IN	R M SCHAHFER	14		8,177	21,692
IN	ROCKPORT	NM2		0	3,082
IN	ROCKPORT	MB1		21,436	28,211
IN	STATE LINE	3		863	514
IN	STATE LINE	4		2,327	1,381
IN	TANNERS CREEK	U1		2,967	3,901
IN	TANNERS CREEK	U3		3,512	4,407
IN	TANNERS CREEK	U2		3,849	3,338
IN	WHITEWATER VALLEY	2		9,396	9,048
IN	WHITEWATER VALLEY	1		3,488	3,418
IA	AMES	8		603	767
IA	AMES	7		257	93
IA	COUNCIL BLUFFS	1		841	620
IA	COUNCIL BLUFFS	3		14,208	11,259
IA	COUNCIL BLUFFS	2		1,451	1,066
IA	DUBUQUE	1		3,400	5,425
IA	DUBUQUE	5		1,269	2,641
IA	EARL F WISDOM	1		1,183	1,062
IA	FAIR STATION	2		7,015	5,294
IA	GEORGE NEAL	2		6,052	4,301
IA	GEORGE NEAL	3		8,889	7,642
IA	GEORGE NEAL	4		10,844	15,877
IA	LANSING	3		1,577	2,814
IA	LANSING	2		85	171
IA	LANSING	4		4,681	3,214
IA	LANSING	1		86	137
IA	LOUISA	101		13,153	14,274
IA	MILTON L KAPP	1		77	0
IA	MUSCATINE	9		1,902	1,821
IA	MUSCATINE	7		1,031	442
IA	MUSCATINE	8		5,151	7,849
IA	OTTUMWA	1		13,364	13,715
IA	PELLA	7		1,448	1,317
IA	PELLA	4		0	0
IA	PELLA	6		961	1,077
IA	PELLA	8		0	0
IA	PRAIRIE CREEK	2		0	0
IA	PRAIRIE CREEK	3		1,941	2,187
IA	PRAIRIE CREEK	1		0	0
IA	RIVERSIDE	8		1,055	1,074
IA	RIVERSIDE	7		1,141	1,279
IA	RIVERSIDE	6		1,029	1,137
IA	RIVERSIDE	9		9,420	3,986
IA	SIXTH STREET	2		0	0
IA	SIXTH STREET	3		0	0
IA	SIXTH STREET	4		0	0
IA	SIXTH STREET	5		0	0
IA	SIXTH STREET	1		9,600	10,537
IA	STREETER STATION	7		2,182	1,549
IA	SUTHERLAND	3		9,128	1,978
IA	SUTHERLAND	1		1,062	1,423
IA	SUTHERLAND	2		501	2,927

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
KY	GREEN RIVER	3		12	11
KY	GREEN RIVER	1		18	8
KY	GREEN RIVER	4		7,193	5,610
KY	H L SPURLOCK	2		15,942	11,498
KY	HENDERSON I	6		710	638
KY	MILL CREEK	2		8,941	10,601
KY	MILL CREEK	1		7,677	8,362
KY	MILL CREEK	3		11,908	13,155
KY	MILL CREEK	4		15,141	14,729
KY	PARADISE	1		19,197	14,431
KY	PARADISE	2		14,713	17,820
KY	PINEVILLE	3		440	307
KY	R D GREEN	G2		7,492	6,195
KY	R D GREEN	G1		6,152	6,654
KY	ROBERT REID	R1		6,772	-
KY	SHAWNEE	7		4,046	2,984
KY	SHAWNEE	6		3,015	2,057
KY	SHAWNEE	5		3,835	3,257
KY	SHAWNEE	9		19,512	15,553
KY	SHAWNEE	8		4,240	2,441
KY	SHAWNEE	1		1,669	1,532
KY	SHAWNEE	4		3,701	1,952
KY	SHAWNEE	2		3,756	2,841
KY	SHAWNEE	3		4,137	2,771
KY	TYRONE	4		0	0
KY	TYRONE	1		0	0
KY	TYRONE	5		844	1,039
KY	TYRONE	2		0	0
KY	TYRONE	3		0	0
LA	ARSENAL HILL	5A		0	0
LA	BIG CAJUN 1	1B2		0	0
LA	BIG CAJUN 1	1B1		1	2
LA	BIG CAJUN 2	2B3		13,040	15,281
LA	BIG CAJUN 2	2B1		15,862	14,592
LA	BIG CAJUN 2	2B2		13,205	17,708
LA	COUGHLIN	6		0	0
LA	COUGHLIN	7		0	5
LA	D G HUNTER	3		0	2
LA	D G HUNTER	4		0	0
LA	DOLET HILLS	1		10,280	9,857
LA	HOUMA	15		0	0
LA	HOUMA	16		0	0
LA	LIEBERMAN	3		0	0
LA	LIEBERMAN	4		0	0
LA	LITTLE GYPSY	3		10	13
LA	LITTLE GYPSY	2		7	14
LA	LITTLE GYPSY	1		3	12
LA	LOUIS DOC BONIN	2		0	0
LA	LOUIS DOC BONIN	3		0	0
LA	LOUIS DOC BONIN	1		0	0
LA	LOUISIANA 1	1A		0	0
LA	LOUISIANA 1	2A		0	0
LA	LOUISIANA 1	ALL		0	0
LA	MICHOUD	1		4	46
LA	MICHOUD	2		8	81
LA	MICHOUD	3		22	9

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MD	R P SMITH	9		602	589
MD	RIVERSIDE	1		337	1,087
MD	RIVERSIDE	2		209	762
MD	RIVERSIDE	3		356	906
MD	RIVERSIDE	5		431	1,100
MD	RIVERSIDE	4		688	640
MD	VIENNA	8		5,880	6,710
MD	WESTPORT	3		335	884
MD	WESTPORT	4		428	1,214
MA	BRAYTON POINT	3		30,533	29,270
MA	BRAYTON POINT	2		14,566	16,634
MA	BRAYTON POINT	4		18,613	21,233
MA	BRAYTON POINT	1		15,254	17,516
MA	CANAL	1		35,718	33,807
MA	CANAL	2		32,781	38,397
MA	CANNON STREET	1		204	136
MA	CANNON STREET	3		541	333
MA	CANNON STREET	2		204	136
MA	CLEARY FLOOD	9		1,404	1,625
MA	CLEARY FLOOD	8		523	651
MA	KENDALL SQUARE	2		49	118
MA	KENDALL SQUARE	3		292	191
MA	KENDALL SQUARE	1		59	119
MA	MOUNT TOM	1		10,601	9,864
MA	MYSTIC	4		4,441	4,601
MA	MYSTIC	6		4,302	3,379
MA	MYSTIC	5		2,394	2,009
MA	MYSTIC	7		10,404	9,218
MA	NEW BOSTON	2		9,171	5,367
MA	NEW BOSTON	1		9,458	7,752
MA	SALEM HARBOR	2		4,240	6,168
MA	SALEM HARBOR	1		4,715	5,729
MA	SALEM HARBOR	3		10,015	10,057
MA	SALEM HARBOR	4		27,086	28,194
MA	SOMERSET	4		0	0
MA	SOMERSET	8		6,466	6,890
MA	SOMERSET	2		0	0
MA	SOMERSET	3		0	0
MA	SOMERSET	7		4,188	4,792
MA	SOMERSET	1		0	0
MA	SOMERSET	5		0	0
MA	SOMERSET	6		0	0
MA	WEST SPRINGRIELD	1		532	520
MA	WEST SPRINGFIELD	2		470	492
MA	WEST SPRINGFIELD	3		3,744	864
MI	B C COBB	4		6,060	6,357
MI	B C COBB	5		6,027	5,717
MI	B C COBB	3		600	845
MI	B C COBB	2		729	860
MI	B C COBB	1		711	1,044
MI	BELLE RIVER	2		16,537	14,296
MI	BELLE RIVER	1		16,447	14,668
MI	CONNERS CREEK	15		736	-
MI	CONNERS CREEK	18		0	-
MI	CONNERS CREEK	16		614	-

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MI	ST CLAIR	7		10,552	17,569
MI	ST CLAIR	6		10,712	9,574
MI	TRENTON CHANNEL	9A		15,958	14,780
MI	TRENTON CHANNEL	16		2,705	2,804
MI	TRENTON CHANNEL	18		2,483	2,441
MI	TRENTON CHANNEL	19		0	0
MI	TRENTON CHANNEL	17		83	0
MI	WYANDOTTE	7		1,125	1,295
MN	ALLEN S KING	1		13,820	33,119
MN	BLACK DOG	2		1,984	492
MN	BLACK DOG	1		966	418
MN	BLACK DOG	3		2,735	1,460
MN	BLACK DOG	4		3,865	3,196
MN	CLAY BOSWELL	4		24,043	22,665
MN	CLAY BOSWELL	1		1,987	2,515
MN	CLAY BOSWELL	2		2,472	1
MN	CLAY BOSWELL	3		18,178	15,433
MN	FOX LAKE	3		2,145	2,094
MN	FOX LAKE	2		0	4
MN	HIGH BRIDGE	3		158	0
MN	HIGH BRIDGE	4		297	905
MN	HIGH BRIDGE	5		1,412	1,323
MN	HOOT LAKE	2		530	822
MN	HOOT LAKE	3		372	878
MN	M L HIBBARD	4		460	386
MN	M L HIBBARD	3		289	469
MN	MINNESOTA VALLEY	3		244	218
MN	NORTHEAST STATION	NEPP		421	342
MN	RIVERSIDE	6		2,768	3,781
MN	RIVERSIDE	8		7,917	9,748
MN	RIVERSIDE	7		3,326	3,682
MN	SHERBURNE COUNTY	1		28,079	19,643
MN	SHERBURNE COUNTY	3		11,633	11,053
MN	SHERBURNE COUNTY	2		24,160	20,230
MN	SILVER LAKE	4		1,416	2,382
MN	SYL LASKIN	1		153	196
MN	SYL LASKIN	2		484	439
MN	WILMARTH	2		0	0
MS	BAXTER WILSON	2		3,624	6,959
MS	BAXTER WILSON	1		156	379
MS	DELTA	1		0	0
MS	DELTA	2		0	62
MS	GERALD ANDRUS	1		6,239	4,523
MS	JACK WATSON	1		0	3
MS	JACK WATSON	2		0	0
MS	JACK WATSON	3		1	1
MS	MOSELLE	3		0	98
MS	MOSELLE	1		7	57
MS	MOSELLE	2		26	126
MS	R D MORROW	2		5,521	6,628
MS	R D MORROW	1		6,160	5,440
MS	REX BROWN	4		43	46
MS	REX BROWN	1A		0	0
MS	REX BROWN	3		0	25
MS	REX BROWN	1B		0	0

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NV	FORT CHURCHILL	2		753	272
NV	FORT CHURCHILL	1		259	252
NV	MOHAVE	2		24,792	20,488
NV	MOHAVE	1		24,527	22,039
NV	NORTH VALMY	1		5,335	5,261
NV	NORTH VALMY	2		1,624	1,835
NV	REID GARDNER	1		2,010	2,176
NV	REID GARDNER	2		2,154	2,035
NV	REID GARDNER	4		2,860	3,340
NV	REID GARDNER	3		2,086	2,232
NV	SUNRISE	1		154	212
NV	TRACY	3		824	331
NV	TRACY	2		14	6
NV	TRACY	1		7	18
NH	NEWINGTON	1		23,307	25,328
NH	SCHILLER	4		2,775	2,909
NH	SCHILLER	6		2,596	2,532
NH	SCHILLER	5		2,480	2,442
NJ	B L ENGLAND	3		2,442	3,380
NJ	BERGEN	1		576	535
NJ	BERGEN	2		521	332
NJ	BURLINGTON	7		882	1,016
NJ	DEEPWATER	9		2,189	1,929
NJ	DEEPWATER	6		0	0
NJ	DEEPWATER	8		2,723	3,019
NJ	DEEPWATER	4		0	15
NJ	DEEPWATER	5		0	0
NJ	DEEPWATER	3		0	0
NJ	DEEPWATER	1		1,055	736
NJ	GILBERT	07		19	24
NJ	GILBERT	04		22	18
NJ	GILBERT	02		151	67
NJ	GILBERT	01		57	95
NJ	GILBERT	05		21	20
NJ	GILBERT	06		22	23
NJ	GILBERT	03		973	1,439
NJ	HUDSON	2		14,083	17,647
NJ	HUDSON	1		178	176
NJ	KEARNY	7		126	204
NJ	KEARNY	8		168	275
NJ	LINDEN	12		967	591
NJ	LINDEN	13		637	741
NJ	LINDEN	2		330	656
NJ	LINDEN	4		176	387
NJ	LINDEN	11		878	777
NJ	MERCER	1		9,197	9,899
NJ	MERCER	2		8,751	8,530
NJ	SAYREVILLE	03		2	1
NJ	SAYREVILLE	05		6	5
NJ	SAYREVILLE	02		4	2
NJ	SAYREVILLE	06		1	10
NJ	SAYREVILLE	08		374	202
NJ	SAYREVILLE	07		214	354
NJ	SEWAREN	4		138	104
NJ	SEWAREN	3		74	97

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NY	DANSKAMMER	1		799	570
NY	DUNKIRK	2		9,251	11,325
NY	DUNKIRK	1		10,291	11,429
NY	E F BARRETT	10		592	283
NY	E F BARRETT	20		874	842
NY	EAST RIVER	50		743	673
NY	EAST RIVER	60		438	519
NY	EAST RIVER	70		113	373
NY	FAR ROCKAWAY	40		189	347
NY	GLENWOOD	50		352	514
NY	GLENWOOD	40		342	486
NY	GOUDEY	11		2,486	2,573
NY	GOUDEY	13		8,977	9,425
NY	GOUDEY	12		2,355	2,389
NY	GREENIDGE	5		2,379	3,393
NY	GREENIDGE	4		2,630	8,450
NY	HICKLING	3		1,879	2,168
NY	HICKLING	2		1,158	1,784
NY	HICKLING	1		1,143	1,824
NY	HICKLING	4		1,879	2,037
NY	HUDSON AVENUE	73		0	-
NY	HUDSON AVENUE	72		0	-
NY	HUDSON AVENUE	71		0	-
NY	HUDSON AVENUE	74		0	-
NY	HUDSON AVENUE	81		0	-
NY	HUDSON AVENUE	83		0	-
NY	HUDSON AVENUE	82		0	-
NY	HUDSON AVENUE	84		0	-
NY	HUDSON AVENUE	100		321	349
NY	JENNISON	2		1,089	1,327
NY	JENNISON	4		1,076	1,150
NY	JENNISON	3		1,078	1,303
NY	JENNISON	1		1,088	1,434
NY	LOVETT	4		1,963	3,276
NY	LOVETT	3		70	458
NY	LOVETT	5		2,907	3,938
NY	NORTHPORT	4		8,076	8,036
NY	OSWEGO	6		8,957	7,914
NY	OSWEGO	5		20,905	20,052
NY	OSWEGO	2		0	0
NY	OSWEGO	1		0	0
NY	OSWEGO	3		0	0
NY	OSWEGO	4		16	799
NY	PORT JEFFERSON	2		631	941
NY	PORT JEFFERSON	1		612	977
NY	RAVENSWOOD	20		507	513
NY	RAVENSWOOD	30		2,900	3,069
NY	RAVENSWOOD	10		495	403
NY	ROCHESTER 7	1		3,122	4,514
NY	ROCHESTER 3	12		7,007	8,139
NY	ROCHESTER 7	2		5,265	6,477
NY	ROCHESTER 7	3		4,678	6,263
NY	ROCHESTER 7	4		5,620	7,731
NY	ROSETON	2		21,496	22,464
NY	ROSETON	1		16,513	23,594
NY	S A CARLSON	9		4,313	3,212
NY	S A CARLSON	10		0	0

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NC	ROXBORO	3B		14,978	0
NC	ROXBORO	3A		14,978	28,489
NC	ROXBORO	2		18,903	22,980
NC	W H WEATHERSPOON	2		643	1,141
NC	W H WEATHERSPOON	1		692	887
NC	W H WEATHERSPOON	3		1,569	1,896
ND	ANTELOPE VALLEY	B2		10,618	10,112
ND	ANTELOPE VALLEY	B1		10,850	8,915
ND	COAL CREEK	1		24,278	26,337
ND	COAL CREEK	2		25,878	26,041
ND	COYOTE	B1		16,903	16,221
ND	LELAND OLDS	1		0	4,326
ND	LELAND OLDS	2		26,803	16,991
ND	MILTON R YOUNG	B2		18,100	18,403
ND	MILTON R YOUNG	B1		16,348	16,132
ND	R M HESKETT	B2		3,467	5,174
ND	STANTON	1		7,977	8,502
ND	STANTON	10		1,344	1,127
OH	ACME	15		0	1
OH	ACME	16		724	570
OH	ACME	9		0	0
OH	ACME	13		0	0
OH	ACME	14		0	0
OH	ACME	11		0	0
OH	ACME	92		597	400
OH	ACME	91		511	427
OH	ASHTABULA	10		5,549	5,303
OH	ASHTABULA	9		5,928	3,711
OH	ASHTABULA	11		6,419	5,874
OH	ASHTABULA	8		3,462	5,731
OH	AVON LAKE	7		0	-
OH	AVON LAKE	9		5,928	3,711
OH	AVON LAKE	10		6,643	7,849
OH	AVON LAKE	8		3,462	5,731
OH	BAY SHORE	2		6,717	4,430
OH	BAY SHORE	1		4,696	5,929
OH	BAY SHORE	3		8,712	6,563
OH	BAY SHORE	4		9,948	11,850
OH	CARDINAL	3		24,252	23,306
OH	CONESVILLE	5		10,809	10,291
OH	CONESVILLE	6		11,467	9,528
OH	EDGEWATER	11		1,598	468
OH	EDGEWATER	13		6,707	8,250
OH	EDGEWATER	12		1,647	650
OH	GORGE	26		2,840	3,136
OH	GORGE	25		2,430	3,047
OH	HAMILTON	8		599	569
OH	HAMILTON	9		904	975
OH	J M STUART	2		48,730	43,413
OH	J M STUART	1		51,470	48,767
OH	J M STUART	3		44,608	46,814
OH	J M STUART	4		50,348	47,393
OH	KILLEN STATION	2		23,571	25,415
OH	LAKE SHORE	92		272	403
OH	LAKE SHORE	91		286	354

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
OK	PONCA	2		0	0
OK	RIVERSIDE	1501		0	0
OK	RIVERSIDE	1502		0	0
OK	SEMINOLE	1		0	0
OK	SEMINOLE	3		8	10
OK	SEMINOLE	2		0	0
OK	SOONER	1		9,386	11,442
OK	SOONER	2		7,253	8,557
OK	SOUTHWESTERN	801N		0	0
OK	SOUTHWESTERN	8002		0	0
OK	SOUTHWESTERN	8003		0	0
OK	SOUTHWESTERN	801S		0	0
OR	BOARDMAN	1SG		-	1,805
PA	BRUCE MANSFIELD	1		14,146	14,536
PA	BRUCE MANSFIELD	2		15,933	10,369
PA	BRUCE MANSFIELD	3		14,526	14,798
PA	CROMBY	2		2,283	2,971
PA	CROMBY	1		3,115	3,223
PA	DELAWARE	71		877	989
PA	DELAWARE	81		673	828
PA	EDDYSTONE	4		1,808	1,572
PA	EDDYSTONE	1		3,149	2,558
PA	EDDYSTONE	2		2,598	3,115
PA	EDDYSTONE	3		1,084	1,772
PA	ELRAMA	4		3,185	3,147
PA	ELRAMA	1		813	1,425
PA	ELRAMA	3		1,455	1,521
PA	ELRAMA	2		797	1,443
PA	FRONT STREET	9		3,845	4,725
PA	FRONT STREET	10		4,069	4,399
PA	HOLTWOOD	17		18,467	19,162
PA	HOMER CITY	1		40,907	45,993
PA	HOMER CITY	3		57,143	24,124
PA	HOMER CITY	2		50,553	37,232
PA	HUNLOCK POWER	6		2,458	2,862
PA	KEYSTONE	2		61,655	73,498
PA	KEYSTONE	1		75,460	64,742
PA	MARTINS CREEK	3		2,045	1,124
PA	MARTINS CREEK	4		1,985	1,551
PA	MITCHELL	2		0	0
PA	MITCHELL	1		0	0
PA	MITCHELL	3		0	0
PA	MITCHELL	33		4,756	4,404
PA	MONTOUR	1		62,734	65,989
PA	MONTOUR	2		62,701	63,215
PA	NEW CASTLE	1		1,092	951
PA	NEW CASTLE	3		5,931	6,419
PA	NEW CASTLE	4		5,743	7,285
PA	NEW CASTLE	2		1,771	1,208
PA	NEW CASTLE	5		7,170	10,933
PA	SCHUYLKILL	1		550	627
PA	SEWARD	12		2,913	2,926
PA	SEWARD	15		9,720	12,005
PA	SEWARD	14		3,000	2,905
PA	SUNBURY	3		14,103	16,444

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TN	KINGSTON	9		14,168	8,758
TN	KINGSTON	8		14,215	0
TN	KINGSTON	1		9,107	9,795
TN	KINGSTON	4		7,090	8,774
TN	KINGSTON	2		6,626	9,406
TN	KINGSTON	3		7,735	9,445
TX	BARNEY M DAVIS	2		12	155
TX	BARNEY M DAVIS	1		2	21
TX	BIG BROWN	2		26,320	32,583
TX	BIG BROWN	1		28,204	28,801
TX	BRYAN	6		0	4
TX	CEDAR BAYOU	CBY2		0	145
TX	CEDAR BAYOU	CBY3		805	81
TX	CEDAR BAYOU	CBY1		0	200
TX	COLETO CREEK	1		14,741	13,433
TX	COLLIN	1		0	184
TX	CONCHO	7		1	0
TX	CONCHO	6		0	0
TX	CONCHO	2		0	0
TX	CONCHO	4		0	0
TX	CONCHO	5		0	0
TX	DALLAS	9		15	46
TX	DALLAS	3		2	55
TX	DANSBY	1		1	5
TX	DECKER CREEK	2		0	5
TX	DECKER CREEK	1		0	2
TX	DECORDOVA	1		106	329
TX	E S JOSLIN	1		1	3
TX	EAGLE MOUNTAIN	3		0	0
TX	EAGLE MOUNTAIN	1		14	95
TX	EAGLE MOUNTAIN	2		23	71
TX	FORT PHANTOM	1		4	56
TX	FORT PHANTOM	2		0	28
TX	GIBBONS CREEK	1		20,272	20,329
TX	GRAHAM	1		9	0
TX	GRAHAM	2		1	32
TX	GREENS BAYOU	GBY5		9	69
TX	HANDLEY	1B		0	0
TX	HANDLEY	1A		0	0
TX	HANDLEY	2		0	0
TX	HANDLEY	3		4	123
TX	HANDLEY	5		41	315
TX	HANDLEY	4		47	247
TX	HARRINGTON STATION	062B		9,332	9,006
TX	HARRINGTON STATION	061B		8,645	8,008
TX	HARRINGTON STATION	063B		8,630	10,471
TX	HOLLY STREET	1		0	2
TX	HOLLY STREET	2		2	7
TX	HOLLY STREET	3		0	9
TX	HOLLY STREET	4		0	0
TX	HOLLY AVE	1		0	0
TX	HOLLY AVE	2		0	0
TX	J L BATES	1		0	0
TX	J L BATES	2		1	3
TX	J T DEELY	1		9,753	10,900
TX	J T DEELY	2		10,998	8,995

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TX	NUECES BAY	6		0	2
TX	O W SOMMERS	1		0	23
TX	O W SOMMERS	2		0	40
TX	OAK CREEK	1		0	22
TX	OKLAUNION	1		4,643	5,387
TX	P H ROBINSON	PHR1		0	0
TX	P H ROBINSON	PHR3		0	0
TX	P H ROBINSON	PHR4		6	179
TX	P H ROBINSON	PHR2		0	0
TX	PAINT CREEK	2		0	17
TX	PAINT CREEK	1		1	16
TX	PAINT CREEK	4		0	12
TX	PAINT CREEK	3		0	35
TX	PARKDALE	1		8	54
TX	PARKDALE	2		7	63
TX	PARKDALE	3		56	75
TX	PERMIAN BASIN	5		0	0
TX	PERMIAN BASIN	6		83	228
TX	PIRKEY	1		21,583	23,101
TX	PLANT X	113B		0	0
TX	PLANT X	111B		0	0
TX	PLANT X	114B		1	0
TX	PLANT X	112B		0	0
TX	POWERLANE	2		0	0
TX	POWERLANE	3		0	0
TX	R W MILLER	3		0	79
TX	R W MILLER	1		0	0
TX	R W MILLER	2		0	26
TX	RAY OLINGER	BW3		0	6
TX	RAY OLINGER	CE1		0	0
TX	RAY OLINGER	BW2		0	0
TX	RIO PECOS	6		0	7
TX	RIO PECOS	5		0	0
TX	RIVER CREST	1		3	41
TX	SABINE	1		0	0
TX	SABINE	4		1	0
TX	SABINE	3		0	0
TX	SABINE	2		0	0
TX	SABINE	5		32	10
TX	SAM SEYMOUR	1		12,601	9,778
TX	SAM SEYMOUR	2		12,820	11,083
TX	SAM SEYMOUR	3		3,635	4,292
TX	SAM BERTRON	SRB3		46	9
TX	SAM BERTRON	SRB4		1	6
TX	SAM BERTRON	SRB2		0	2
TX	SAM BERTRON	SRB1		0	1
TX	SAN ANGELO	2		0	14
TX	SAN MIGUEL	SM-1		18,924	19,727
TX	SANDOW	4		27,494	26,513
TX	SEAHOLM	9		0	0
TX	SIM GIDEON	1		0	16
TX	SIM GIDEON	3		0	29
TX	SIM GIDEON	2		0	44
TX	SPENCER	5		0	5
TX	SPENCER	4		0	7
TX	STRYKER CREEK	1		4	25
TX	STRYKER CREEK	2		6	181

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
VA	CHESAPEAKE	1		4,565	6,466
VA	CHESTERFIELD	6		20,931	25,748
VA	CHESTERFIELD	4		7,648	6,963
VA	CHESTERFIELD	3		3,471	3,367
VA	CHESTERFIELD	5		15,482	14,628
VA	CLINCH RIVER	1		6,247	8,260
VA	CLINCH RIVER	3		7,155	7,309
VA	CLINCH RIVER	2		6,477	7,386
VA	GLEN LYN	5		1,197	2,040
VA	GLEN LYN	6		5,563	7,087
VA	POSSUM POINT	2		0	510
VA	POSSUM POINT	3		2,810	3,202
VA	POSSUM POINT	1		0	165
VA	POSSUM POINT	5		4,521	7,865
VA	POSSUM POINT	4		7,789	9,090
VA	POTOMAC RIVER	2		1,547	2,806
VA	POTOMAC RIVER	1		1,565	2,694
VA	POTOMAC RIVER	3		3,968	3,494
VA	POTOMAC RIVER	5		4,017	3,916
VA	POTOMAC RIVER	4		3,208	4,157
VA	YORKTOWN	1		8,662	9,318
VA	YORKTOWN	2		8,660	8,706
VA	YORKTOWN	3		7,107	8,489
WA	CENTRALIA	BW22		32,722	31,186
WA	CENTRALIA	BW21		29,334	31,076
WA	KETTLE FALLS	1		0	0
WA	SHUFFLETOWN	2		-	261
WA	SHUFFLETOWN	1		-	303
WA	SHUFFLETOWN	3		-	303
WV	ALBRIGHT	1		7,828	7,440
WV	ALBRIGHT	2		7,962	7,497
WV	JOHN E AMOS	2		22,226	25,387
WV	JOHN E AMOS	1		27,287	22,625
WV	JOHN E AMOS	3		35,353	37,896
WV	KANAWHA RIVER	2		5,797	4,548
WV	KANAWHA RIVER	1		5,757	4,547
WV	MOUNTAINEER	1		33,984	40,064
WV	PHIL SPORN	11		3,017	5,814
WV	PHIL SPORN	21		5,888	4,393
WV	PHIL SPORN	51		14,006	17,916
WV	PHIL SPORN	31		3,628	5,936
WV	PHIL SPORN	41		3,418	6,334
WV	PLEASANTS	1		18,233	22,977
WV	PLEASANTS	2		20,851	24,139
WV	RIVESVILLE	8		2,832	3,896
WV	RIVESVILLE	7		1,785	1,520
WV	WILLOW ISLAND	1		2,859	2,267
WV	WILLOW ISLAND	2		12,004	11,004
WI	ALMA	B5		2,890	3,365
WI	ALMA	B2		189	0
WI	ALMA	B4		2,188	2,383
WI	ALMA	B1		189	326
WI	ALMA	B3		188	326
WI	BAY FRONT	2		0	0

State	Plant Name	Unit	Basic Allowance Allocations (Tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
WY	DAVE JOHNSTON	BW44		4,781	4,058
WY	DAVE JOHNSTON	BW42		3,908	3,755
WY	JIM BRIDGER	BW73		5,214	5,748
WY	JIM BRIDGER	BW72		5,588	5,011
WY	JIM BRIDGER	BW71		5,736	5,682
WY	JIM BRIDGER	BW74		3,770	3,528
WY	LARAMIE RIVER	3		3,855	3,361
WY	LARAMIE RIVER	1		4,175	2,643
WY	LARAMIE RIVER	2		3,571	3,897
WY	NAUGHTON	1		10,162	8,993
WY	NAUGHTON	2		11,300	13,335
WY	NAUGHTON	3		5,054	5,248
WY	NEIL SIMPSON	5		801	838
WY	OSAGE	1		728	842
WY	OSAGE	3		714	816
WY	OSAGE	2		741	838
WY	WYODAK	BW91		7,091	5,612

Appendix C to Part 72—Acid Rain Permit Program Forms

PHASE I ACID RAIN PERMIT PROGRAM
FORMS INSTRUCTIONS PACKAGE

- PROGRAM INFORMATION
  - Introduction
  - Table of Contents
  - General Instructions
  - Glossary (to be added)
- FORMS AND INSTRUCTIONS
  - Certificate of Representation Froms 7220 and 7220A
  - Acid Rain Phase I Permit Application Forms 7231 and 7231A
  - Substitution Plan Form 7241
  - Phase I Extension Early Ranking Application Form 7242
  - Phase I Extension Plan Form 7242A
  - Reduced Utilization Plan Form 7243
  - Reduced Utilization Plan Verification Form 7243A
  - NO_x Emissions Averaging Plan Form 7246*
  - NO_x Alternative Emissions Limitation Proposal Forms 7247 and 7247A*
  - NO_x Deadline Extension Forms 7248*
  - Annual Compliance Certification Report Form 72402
  - Utilization Report Form 72409
  - Forced Outage Report Form 72409A
  - Excess Emissions Offset Planning Form 772 (Part 77)
  - Excess Emissions Penalty Forms 774 and 774A (Part 77)
  - Phase I Acid Rain Permit Form 7251 (from 40 CFR § 72.51)

* These forms will be included in Part 76 Regulation.

~~776~~ 4/6

III. GENERAL INSTRUCTIONS

A. Who Must Apply

The regulations governing the Acid Rain Program require that the following stationary sources apply for a Phase I Acid Rain permit.

- Each source that includes an affected unit listed in Appendix A
- Each source that includes a unit not listed in Appendix A that is designated as an "affected unit" as follows:
  - A substitute unit designated in a substitution plan;
  - A compensating unit designated in a reduced utilization plan;
  - Each source that elects to become an affected source pursuant to Part 74.

Affected sources and affected units may not be exempted from the permitting requirements of the Acid Rain Program.

The individual responsible for submission of the Acid Rain permit application is the **Designated Representative** for the source that includes an affected unit or proposed affected unit. The Designated Representative is the "responsible official" for a source in the context of the Acid Rain Program, and must be approved by EPA pursuant to a certification process that establishes the authority of the Designated Representative to represent all units under his or her control. The certification of the Designated Representative is a prerequisite to EPA issuance of an Acid Rain permit or acceptance of allowance transactions.

The Designated Representative is required to certify (by signing the form) to the truth, accuracy and completeness of each form that he or she submits. The Designated Representative, the owner, and operators of the unit are liable for all violations of the Acid Rain law and regulations, and these certifications reiterate the obligations of all the responsible parties for compliance with the Acid Rain Program.

The proposed Designated Representative must apply for EPA approval of the certification by submitting Certificate of Representation Forms SF#[7220] for each affected source and SF#[7220A] for each affected unit at the source. See the instructions for those forms at pp. ____ for more information.

The **Reduced Utilization Plan** and the **Phase I Extension Plan** are multi-unit plans that can involve sources with different Designated Representatives. When submitting such plans, each Designated Representative must sign a proposed compliance option form and submit a copy with the permit application for each source involved. For the other multi-unit plans, **Substitution** or **NO_x Averaging**, all units and sources involved must be represented by the same Designated Representative.

B. When to File

- The Certificate of Representation forms must be postmarked no later than midnight **February 15, 1993**. To expedite allowance trading and permit processing, we suggest you submit these forms as early as possible.
- Phase I permit applications including proposed compliance plans must be postmarked no later than midnight, **February 15, 1993.**
- If possible, Acid Rain Program compliance option forms should be submitted with the permit application. If you submit a compliance option form after the permit application has been processed, a permit revision may be necessary. Because some compliance options have specific deadlines, a comprehensive list of the final date on which each form may be submitted is provided in Figure 1, below.

FIGURE 1: ACID RAIN COMPLIANCE OPTION FILING DEADLINES

Form Number	Compliance Option Form Name	Deadline
7241	**Substitution Plan**	**Any time during Phase I**, as a permit revision
7242	**Phase I Extension Early Ranking Plan**	
7242A	**Phase I Extension Plan**	
7243	Reduced Utilization Plan	**Any time during Phase I**, as a permit revision
7246	NO_x Emissions Averaging Plan	**Any time during Phase I or Phase II**, as a permit revision
7247	NO_x Alternative Emissions Limitation Proposal	**Any time during Phase I or Phase II**, as a permit revision
7247A	NO_x Alternative Emissions Limitation Proposal	no later than **90 days** before end of demonstration period
7248	NO_x Deadline Extension	**December 31, 1994**

State Air Pollution Agencies

State of **Alabama**, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of **Arizona**, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of **Arkansas**, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of **California**, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of **Colorado**, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

State of **Connecticut**, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of **Delaware**, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 5000 Overlook Avenue S.W., Washington D.C. 20032.

State of **Florida**, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of **Georgia**, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of **Idaho**, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of **Illinois**, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of **Indiana**, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206

State of **Iowa**, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of **Kansas**, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of **Kentucky**, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of **Louisiana**, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of **Maine**, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of **Maryland**, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of **Massachusetts**, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of **Michigan**, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.

State of **Minnesota**, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of **Mississippi**, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of **Missouri**, Department of Natural Resources, P.O. Box 1368, Jefferson City, Missouri 65101.

State of **Montana**, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of **Nebraska**, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.

State of **Nevada**, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of **New Hampshire**, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of **New Jersey**, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.

State of **New Mexico**, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of **New York**, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.

State of **North Carolina**, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of **North Dakota**, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

State of **Ohio**, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.

State of **Oklahoma**, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of **Oregon**, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.

Commonwealth of **Pennsylvania**, Department of Environmental Resources, 105 S. Second Street, P.O. BOX 2357, Harrisburg, Pennsylvania 17120.

State of **Rhode Island**, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of **South Carolina**, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of **Tennessee**, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of **Texas**, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of **Utah**, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 841160690.

State of **Vermont**, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of **Virginia**, Virginia State Air Pollution Board, Room 1106, Ninth Street Office Building, Richmond, Virginia 23219.

State of **Washington**, Department of Ecology, Olympia, Washington 98504.

State of **West Virginia**, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of **Wisconsin**, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

GLOSSARY OF ACID RAIN PROGRAM TERMS

[to be added]

DRAFT 7220

Date 10/21/91

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Certificate of Representation (Single Source)

Follow instructions for Form 7220.

I. DESIGNATED REPRESENTATIVE IDENTIFICATION

Designated Representative

A. Last Name | B. First Name | C. MI

D. Street or P.O. Box

E. City | F. State | G. Zip

H. Phone *(area code & number)* | I. Facsimile *(area code & number)*

FOR EPA USE ONLY

Designated Representative Identification Number

Alternate Designated Representative

A. Last Name | B. First Name | C. MI

D. Street or P.O. Box

E. City | F. State | G. Zip

H. Phone *(area code & number)* | I. Facsimile *(area code & number)*

FOR EPA USE ONLY

Alternate Designated Representative Identification Number

II. SOURCE IDENTIFICATION

A. Source Name

B. Street or P.O. Box

C. City | D. State | E. Zip

Source ARP ID Number

Please type or print in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

IV. UNIT IDENTIFICATION

A. Appendix A Units

If more than 4 units, copy this page and enter number of copies here ⟶

1. Unit Name

1

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

2

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

3

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

4

2. Short Name | 3. Unit ARP ID Number

B. Non-Appendix A Units

If more than 4 units, copy this page and enter number of copies here ⟶

1. Unit Name

1

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

2

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

3

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

4

2. Short Name | 3. Unit ARP ID Number

DRAFT 7220A

Date 10/21/91

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Certificate of Representation
(Individual Unit Information)

Follow instructions for Form 7220A.

I. UNIT IDENTIFICATION

A. Name

B. Unit Short Name

C. Unit ARP ID Number

II. UNIT OWNERS AND OPERATORS

A. Unit Owners

If more than 5 owners, copy this page and enter number of copies here ——→

1
1. Name
2. Street or P.O. Box
3. City | 4. State | 5. Zip

2
1. Name
2. Street or P.O. Box
3. City | 4. State | 5. Zip

3
1. Name
2. Street or P.O. Box
3. City | 4. State | 5. Zip

4
1. Name
2. Street or P.O. Box
3. City | 4. State | 5. Zip

5
1. Name
2. Street or P.O. Box
3. City | 4. State | 5. Zip

788 428

FORMS #7220 and 7220A
CERTIFICATE OF REPRESENTATION FORMS

INTRODUCTION

Title IV of the Clean Air Act requires that the owners of record for each affected unit in the Acid Rain program must choose a Designated Representative and may choose an alternative Designated Representative to act when the Designated Representative is indisposed. The regulations that govern the Designated Representative are found at 40 CFR § 72.20 et seq. (Subpart B of the Title IV Permit Regulations). The owners must choose the Designated Representative and the Alternate through a process that assures that all owners have notice regarding the selection. All affected units at a single source must have the same Designated Representative, and all units that seek to participate in a multi-source substitution plan must be represented by the same Designated Representative.

The Designated Representative will be responsible for all submissions regarding the unit under his or her control, and will conduct allowance transactions for the unit. The Designated Representative shares liability with the Alternate Designated Representative, the owners and operators of the unit for any violations of the Acid Rain title.

The regulations state that EPA will neither issue an Acid Rain permit nor record any allowance transactions until the Designated Representative has filed and EPA has approved a complete certificate of representation. The request for certification must be filed on the standard forms provided for that purpose. The Certificate of Representation forms serve to identify each Phase I affected source for which a Designated Representative will be responsible (Form #7220), and to verify for the sources, as well as unit by unit, that the Designated Representative and Alternate Designated Representative are authorized to take responsibility for Acid Rain Program submissions (Forms #7220 and 7220A). For Phase I, these forms must be submitted no later than **February 15, 1993**, (the deadline for Acid Rain Phase I permit applications). EPA recommends early submission of these forms to forestall delays in allowance transactions and permit processing.

INSTRUCTIONS FOR FORM #7220
CERTIFICATE OF REPRESENTATION
(SINGLE SOURCE)

Top Center of Each Page of the Form: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. DESIGNATED REPRESENTATIVE IDENTIFICATION

A.-I. Enter the name, mailing address, and telephone and facsimile numbers for the Designated Representative and for the Alternate, if one is proposed.

II. SOURCE IDENTIFICATION

In this section, provide the information for a source or facility that contains one or more affected units for which the person(s) named in Part I be serving as Designated Representative (and Alternate Designated Representative).

A. Name: Provide the name of the source or facility. This name will include the company name and a name for the source, e.g., "ABC Utility Electric Power Station."

B-E. Mailing Address: Provide the source mailing address.

III. SOURCE OWNERS AND OPERATORS OF RECORD

A. Provide the name and mailing address of each owner of record for the source. The owner can be a person or a corporation. If there are more than four owners, photocopy this page before completing it, and indicate how many copies your are including.

B. Provide the name and mailing address for each operator of record of the source. These persons include [to be added]. If there are more than two operators, copy this page before completing it, and indicate how many copies you are including.

IV. UNIT IDENTIFICATION

List the affected units at the source identified in Part II, above. In **Section A**, provide information for Appendix A units. In **Section B**, list any non-Appendix A units that you will be proposing as part of a compliance option, or other units at the source for which you would like to designate a representative for purposes of allowance transactions. (You will need to complete a Standard Form 7220A for each of the units you list.) For each unit provide the following:

1. Fill in the name of the affected unit (e.g., "ABC Elect. Gen. Unit #4.")

2. Give a short name that is commonly used or could be used as an easy identification of the unit (e.g., "ABC #4.")

3. Provide the Acid Rain Program Identification Number for the unit, which is the source number appearing at the top center of this form plus three digits that identify the unit (e.g., "004"). Enter the three digits in the space provided. (Acid Rain Program unit ID numbers are listed in Appendices A and B of 40 CFR Part 72.)

V. AGREEMENT OF REPRESENTATION

This section lists the requisite elements for the Agreement of Representation between the Designated Representative and the Alternate Designated Representative and the owners. EPA will not accept and certify the Designated Representative or the Alternate Designated Representative to represent the unit in all Acid Rain regulatory matters unless the Designated Representative (or both of them) certifies that such an agreement exists.

The applicant will need to check the box that more accurately describes the term of the agreement relating to distribution of proceeds from allowance transfers.

FORMS 7231 AND 7231A

Application for Phase I Acid Rain Permit

Form 7231

Application for Phase I Acid Rain Permit
(Source Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7231A

Application for Phase I Acid Rain Permit
(Unit Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

792 432

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

B. Non-Appendix A Units

If more than 4 units, copy this sheet and enter number of copies here ——→

	1. Unit Name	2. Short Name	3. Unit ARP ID Number
1			
2			
3			
4			

III. CERTIFICATE OF REPRESENTATION

☐ Certificate of Representation for this source and each unit at this source is included (either original or copy).

IV. STANDARD PROVISIONS & PROHIBITIONS

A. Duties, Prohibitions and Liability

1. **Duties.** Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR Part 72. The duties are as follows:
   a. To submit a permit application and proposed compliance plan under 40 CFR Part 72 in accordance with the deadlines specified in §72.30;
   b. To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application;
   c. To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with Title IV of the Act and of 40 CFR Part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority;
   d. To operate the unit in compliance with the monitoring requirements of 40 CFR Part 75;
   e. In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR Part 77; and
   f. In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR Part 77 and an approved offset plan as required by 40 CFR Part 77.

2. **Prohibitions.** Any violation of the following prohibitions shall be a violation of the Act and 40 CFR Part 72 by the owners, operators and designated representative of the affected unit and/or affected source:
   a. No affected unit shall exceed the applicable emissions limitations of 40 CFR Parts 72-78, as follows:
      i. No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR Part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.
      ii. No affected unit shall emit nitrogen oxides in excess of:
         A. the annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR Part 76; or,
         B. the superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR Part 72, Subpart D and 40 CFR Part 75;
   b. No person shall hold, use, or transfer any allowance except in accordance with Title IV of the Act and the regulations in 40 CFR Parts 72-78;
   c. No person shall use an allowance prior to the calendar year for which the allowance was allocated; and,
   d. No person shall make a false statement in any submission required under 40 CFR Parts 72-78, inclusive.

NOTE: Section IV. STANDARD PROVISIONS & PROHIBITIONS is continued on Page 3 of this form ——→

Please type or print in the unshaded areas only.

Source ARP ID Number											

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: _____

2. Date of Initial Review: _____ By: _____

   a. ☐ Complete ☐ Incomplete

   b. ☐ Approved ☐ Disapproved Explain: _____

   _____

3. Date of Final Approval: _____ By: _____

4. Date Notice Sent: _____ By: _____

Comments:

_____

_____

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Source ARP ID Number

Please type or print in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

V. COMPLIANCE PLAN INFORMATION

A. Sulfur Dioxide Compliance Plan

1. This Appendix A Unit *(mark a or b)*:

☐ a. Will hold allowances to emit not less than its total annual emissions and will not use other compliance options.

☐ b. Will hold allowances to emit not less than its total annual emissions and seeks approval for the following compliance option(s): *(mark all that are applicable)*

☐ i. Reduced utilization *(attach Form #XXXX).*

☐ ii. Substitution *(attach Form #XXXX).*

☐ iii. Phase I extension *(attach Form #XXXX).*

2. This Non-Appendix A Unit seeks approval for its participation in Phase I as:

☐ a. An opt-in unit *(attach Form #XXXX).*

☐ b. Part of a reduced utilization plan *(attach Form #XXXX).*

☐ c. Part of a substitution plan *(attach Form #XXXX).*

☐ d. Part of a Phase I extension plan *(attach Form #XXXX).*

B. Nitrogen Oxides Compliance Plan

This Appendix A Unit:

☐ 1. Will meet the Title IV statutory emissions limit.

☐ 2. Seeks approval for the following compliance option(s):

☐ a. Emissions averaging *(attach Form #XXXX).*

☐ b. Alternative emissions limits *(attach Form #XXXX).*

☐ c. Deadline extension *(attach Form #XXXX).*

VI. STANDARD PROVISIONS AND PROHIBITIONS

The standard provisions and prohibitions from Part IV of the **Application for a Phase I Acid Rain Permit (Source Information)** are incorporated by reference and shall apply with full force and effect to this unit.

VII. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Received: _____

2. Date of Initial Review: _____ By: _____

a. ☐ Complete ☐ Incomplete

b. ☐ Approved ☐ Disapproved Explain: _____

3. Date of Final Approval: _____ By: _____

4. Date Notice Sent: _____ By: _____

Comments: _____

IV. STANDARD PROVISIONS AND PROHIBITIONS

These provisions and prohibitions apply to all Acid Rain permit applications and proposed compliance plans, which are binding until EPA either makes an initial permitting decision or disapproves the application. These provisions apply to the source and to all affected units that are a part of that source.

V. CERTIFICATION

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM 7231A
APPLICATION FOR PHASE I ACID RAIN PERMIT
(UNIT INFORMATION)

Top Center of Each Page of the Application: Enter the Acid Rain Program Identification Number (the AIRS number) for the source at which the unit is located.

I. UNIT IDENTIFICATION

A. Enter the unit Acid Rain Identification Number; this number (15 digits) appears in Appendix A or Appendix B, wherever the unit is listed.

B. Enter the short name that is commonly used or could be used for easy identification of the unit (e.g., "ABC #4").

C. Mark whether or not the unit is listed on Appendix A in 40 CFR Part 73. If you are submitting the application for a non-Appendix A unit, further identify the unit:

2a. An **Existing Unit** is a unit that commenced commercial operation before November 15, 1990, including any unit that is modified, reconstructed or repowered after November 15, 1990. Existing unit does not include a simple combustion turbine or a unit that serves a generator with a nameplate capacity of 25 MWe or less.

2b. An **Opt-in Unit is a unit defined in 40 CFR Part 74 as** _____.

2c. A **New Unit is:** (i) any unit that commenced commercial operation on or after November 15, 1990, including any unit that serves a generator with a nameplate capacity of 25 MWe or less or is a simple combustion turbine; or, (ii) any unit that commenced commercial operation prior to November 15, 1990 but only began to serve a generator with a nameplate capacity of greater than 25 MWe on November 15, 1990 or after.

D. Mark all applicable boxes that apply to this unit:

1. Mark whether the unit is coal-fired. Only coal-fired units can become affected units for nitrogen oxides, and only those units with tangentially fired boilers or dry bottom wall-fired boilers (other than units applying cell burner technology) are subject to a Title IV Nitrogen Oxides emission limit in Phase I.

2. Indicate whether the unit is multi-header.

3. Indicate whether this unit shares a common stack. All units that share a common stack must complete a common stack plan, on SF#____.

E. Indicate whether this unit has either or both of the boiler type(s) listed by marking appropriate check boxes.

II. EMISSIONS LIMITATIONS

A. Sulfur Dioxide Emissions Limitations

1. For a unit that is listed in Appendix A at 40 CFR Part 72, enter the allowance allocation from the Appendix. If the unit proposes a compliance option that would alter the allowance allocation, you will be indicating this in Part V of the form.

2. Enter the most stringent federally enforceable sulfur dioxide emissions emulation that is applicable at the time of the application.

B. Nitrogen Oxides

Mark either 1 or 2.

1. If you checked either box in Part 1 E, above, this unit is regulated under Title IV for nitrogen oxides in Phase I. Mark this box, and indicate whether the unit:

a. will comply with the statutory limit, or

b. proposes a different limit under a Nitrogen Oxide compliance option.

2. Mark this box if your unit does not have either of the boiler types listed in Part I E, above. This means that the unit will not be subject to Title IV Nitrogen Oxides limits at this time. This does not preclude the regulation of Nitrogen Oxides under another title of the Act through the source operating permit.

3. Enter the most stringent federally enforceable nitrogen oxides emissions limitation that is applicable at the time of the application.

III. UTILIZATION INFORMATION

Complete This Section for Appendix A Units Only.

A. Enter the heat input baseline, which is listed in Appendix A at 40 CFR Part 72.

B. Enter the average annual generation during the baseline years.

C. Enter annual projections of utilization for the unit for all years of Phase I (1995-1999).

The unit will fill in either subsection 1 or 2. The directions are the same for both Appendix A and Non-Appendix A Units.

a. **Title IV Limit:** Mark this box if you plan to meet the statutory emissions limit that applies to the boiler or boilers at your unit.

b. Mark this box if the unit seeks approval for one or more of the listed compliance options, and also indicate the options for which approval is sought by marking the appropriate box(es):

i. **Emissions Averaging:** Clean Air Act Section 407(e) and the regulations implementing that Part at 40 CFR §72.46, allow the Designated Representatives of two or more units subject to the Title IV emissions limit to submit a proposal to set alternative contemporaneous annual emissions limits for the units. These new limits must assure that the resulting emissions will be no greater than they would have been had the statutory limits been applied at each unit. A more complete description of this provision and of the components of the plan will be included in Part 76.

ii. **Alternative Emission Limitation:** Clean Air Act Section 407(d) and the regulations implementing that Section at 40 CFR §72.47 allow the Administrator to authorize an alternative NO_x emissions limit for a unit that can adequately demonstrate its inability to meet the limit using NO_x low burner technology. A more complete description of this provision and of the components of the plan will be included in Part 76.

iii. **Deadline Extension:** Clean Air Act Section 407(d) and the regulations implementing that Section at 40 CFR §72.48 allow the Administrator to extend the deadline by up to 15 months for compliance by a unit if that unit can demonstrate adequately that the technology necessary to meet the statutory requirement is not in adequate supply. A more complete description of this provision and of the components of the extension will be included in Part 76.

VI. STANDARD PROVISIONS AND PROHIBITIONS

The standard provisions and prohibitions in the source application form (SF# 7231) are incorporated by reference into this unit application and apply with full force and effect to this unit.

VII. CERTIFICATION

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

DRAFT 7241

Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Substitution Plan (Multiple Unit/Multiple Source)

Follow instructions for Form 7241.

I. APPENDIX A UNITS

If more than 3 units, copy this page and enter number of copies here →

	A. Unit ARP ID Number	B. Short Name	C. Emissions Rate	D. 1985 Tons
1				
2				
3				

E. Total 1985 Tons

F. Total Annual Reductions Without Plan

G. Proposed Annual Tons Sulfur Dioxide:

		1995	1996	1997	1998	1999
1	Proposed Tons SO_2					
2	Proposed Tons SO_2					
3	Proposed Tons SO_2					
H.	Total Proposed Tons SO_2					
I.	Total Proposed Annual Reductions *(TPY)*	1995	1996	1997	1998	1999

II. SUBSTITUTION UNITS

If more than 3 units, copy this page and enter number of copies here →

☐ I include a copy of a complete permit application for the other sources at which any substitution units in this plan are located

	A. Unit ARP ID Number	B. Short Name	C. Emissions Rate	D. 1985 Tons
1				
2				
3				

E. Total 1985 Tons

F. Total Annual Reductions Without Plan

G. Proposed Yearly Tons Sulfur Dioxide Required to Satisfy the Plan:

		1995	1996	1997	1998	1999
1	Proposed Tons SO_2					
2	Proposed Tons SO_2					
3	Proposed Tons SO_2					
H.	Total Proposed Tons SO_2					
I.	Total Proposed Annual Reductions Required to Satisfy the Plan *(TPY)*	1995	1996	1997	1998	1999

III. ACTIVATION AND TERMINATION OF PLAN

A. Activation

Choose one:

☐ 1. If approved, this plan will go into effect on *(mm/dd/yy)*:

☐ 2. The Designated Representative will notify the Administrator of activation of the approved plan.

B. Termination

This plan will remain in effect until *(mm/dd/yy)*:

444 804

FORM #7241
SUBSTITUTION PLAN

INTRODUCTION

Clean Air Act Section 404(b) and the regulations implementing that section at 40 CFR §72.41 allow the designated representative for Appendix A units to submit a proposal to reassign all or part of the units' Phase I sulfur dioxide emissions reduction requirement to any Appendix B unit or units ("substitute units") under the control of the same designated representative. The proposal must identify the original and substitute units, propose new emissions limitations for the units in the plan, and demonstrate that the new limitations will achieve an equal or greater emissions reduction than would have been achieved by all of the units without the substitution.

The deadline for the submission of substitution plans is **February 15, 1993**. A substitution plan can only be in effect during Phase I (January 1, 1995 - December 31, 1999) but the unit may elect to activate its approved substitution plan at any time during the Phase.

The Appendix B units that are brought into Phase I become affected units for Phase I. The designated representative must file a Phase I Acid Rain Permit Application for each such unit, and the units must meet all applicable requirements.

INSTRUCTIONS

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source to which you are attaching this plan. If more than one source is involved, you can save some time by leaving the spaces for the source Identification Number blank, and completing the plan form up through Part IV. Then make enough photocopies of the plan forms for each source involved, fill in the source numbers, and sign each form individually.

I. APPENDIX A UNITS

Unit Identification: Identify the original affected "Appendix A" unit or units that are proposed for this substitution plan. If more than three units are proposed, photocopy this form and enter the number of copies in the space provided.

A. Provide the Acid Rain Program Identification Number for the unit(s); you will find this in Appendix A of 40 CFR Part 72.

B. Enter the short name for the unit given in the Acid Rain Application (SF# 7231A) at Part I, Section B.

C. Enter the lesser of the actual or allowable 1985 emissions rates for the unit, from Appendix A.

D. Enter the total 1985 tons for each unit. The sample worksheet in Figure 1 indicates the necessary calculations for the proposed units.

FIGURE 1: WORKSHEET

a. _____(mmBtu)
b. _____(lbs/mmBtu)
c. _____(lbs)
d. _____(tons)

For each unit:

a. Enter the baseline (from Appendix A).

b. Enter the lesser of the 1985 actual or allowable emissions rates (from Column C of the form).

c. Enter the product of the baseline multiplied by the emissions rate.

d. Divide by 2,000 to get tons. Enter this figure in column D in the space corresponding to the unit.

E. Total the figures in column D and enter total 1985 tons for these three units.

F. To calculate the Total Annual Reductions without the plan, add together the allowance allocations for each of the units (from Appendix A). Subtract this total from the total 1985 tons (entered at E) and enter the result.

G. Proposed Yearly Tons SO_2 Under Plan: For each year that the substitution plan is proposed, fill in the proposed tons of SO_2 for that year (place information in the spaces corresponding to the numerical listing in Section A). If a plan is not proposed for a particular year, enter "NO PLAN PROPOSED" so that it is clearly readable in the white space.

H. Add down the columns and enter sum of all proposed tons for each year of the plan.

I. Enter the Total Proposed Annual Reductions for all the Appendix A units. To calculate this figure, subtract the Total Proposed Tons listed in I H from the Total 1985 Tons (figure listed in I D) **Note:** This number will be a negative number if the Appendix A unit will increase emissions from 1985 levels.

II. SUBSTITUTION UNITS

Unit Identification: Identify the substitution units that are proposed for this substitution plan. If more than three units are proposed, photocopy this form and enter the number of copies in the space provided.

A. Provide the Acid Rain Program Identification Number for the unit(s); you will find this in Appendix B of 40 CFR Part 72.

B. Enter the short name for the unit given in the unit Acid Rain Application (SF# 7231A) at Part I, Section B.

C. Enter the lesser of the actual or allowable 1985 emissions rate.

FORMS 7242 AND 7242A

Phase I Extension Plan

Form 7242

Phase I Extension Early Ranking Application

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7242A

Phase I Extension Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

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Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

II. TRANSFER UNITS

If more than 5 units, include copies of this page and enter number of copies here →

	A. Unit ARP ID Number	B. Short Name	C. 1988-89 Average Emissions *(TPY)*
1			
2			
3			
4			
5			

D. Projected Heat Input *(mmBtu)*, Sulfur Dioxide Emissions Rate *(lbs/mmBtu)* and Sulfur Dioxide Emissions *(TPY)*

		1995	1996	1997	1998	1999
1	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
2	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
3	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
4	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
5	*mmBtu*					
	lbs/mmBtu					
	TPY					

E. Proposed Phase [illegible] Reserve Allowances [illegible] *(TPY)*:

F. Proposed Total Allowance Allocation *(TPY)*:

	1995	[illegible]	1996	1996	1997	1998	1999
1							
2							
3							
4							
5							

Enter totals in the unnumbered blocks at the bottom of each column

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VII. CERTIFICATIONS

I certify that I am the Designated Representative for the units that are the control units in the Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*		
B. Signature	C. DR ID Number	D. Date Signed

I certify that I am the Designated Representative for the unit identified below that is a transfer unit in the attached Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

_____

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Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

II. TRANSFER UNITS

If more than 5 units, include copies of this page and enter number of copies here →

	A. Unit ARP ID Number	B. Short Name	C. 1988-89 Average Emissions *(TPY)*
1			
2			
3			
4			
5			

D. Projected Heat Input *(mmBtu)*, Sulfur Dioxide Emissions Rate *(lbs/mmBtu)* and Sulfur Dioxide Emissions *(TPY)*

		1995	1996	1997	1998	1999
1	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
2	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
3	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
4	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
5	*mmBtu*					
	lbs/mmBtu					
	TPY					

	E. Proposed Phase I Extension Reserve Allowances Requested *(TPY)*:		F. Proposed Total Allowance Allocation *(TPY)*:				
	1995	1996	1995	1996	1997	1998	1999
1							
2							
3							
4							
5							

Enter totals in the unnumbered blocks at the bottom of each column

Source ARP ID Number

Please print or type in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VI. STANDARD PROVISIONS & PROHIBITIONS (cont.)

B. Test Methods
Each Phase I Extension plan shall include an emissions monitoring plan as required by 40 CFR Part 75 for each unit governed by the plan and a certification that continuous emissions monitoring systems are or not later than November 15, 1993 will be operational and certified by the Administrator on each Phase I extension control and transfer unit, as required by 40 CFR Part 75.

C. Recordkeeping Requirements
Records demonstrating compliance with the plan, including records demonstrating compliance with any performance standard or scheduled increment of progress throughout Phase I, must be maintained for a minimum of five years in accordance with Section 72.10. Such records shall include emissions monitoring records maintained in accordance with Part 72 and 40 CFR Part 75.

D. Reporting/Compliance Certification Requirements
1. The designated representative shall submit compliance certification reports for each affected source with a unit governed by the plan in accordance with subpart K of 40 CFR Part 72 evidencing each unit's compliance with the requirements of the plan.
2. The designated representative of each control unit shall submit the start-up performance test results and annual recertification test results or other approved test-method results with the quarterly emissions monitoring report for the quarter during which the test was conducted.

E. Prohibitions and Liability
1. It shall be a violation of the Act for any source or unit subject to an approved Phase I Extension plan under this section to operate in violation of the emissions limitation in Part VI.A., above.
2. The owners, operators, and the designated representatives of all control or transfer units shall be liable for any violation of the plan at any unit governed by the Phase I extension plan.
3. Failure to achieve 90% control during the 30-day start up test or annual 30-day recertification test shall be a violation of the Act.
4. In addition to the penalties that accrue as a result of any other liability under the Act, the Administrator shall withhold the allocation of Phase I extension allowances for any calendar year in which the unit fails to demonstrate by December 31 of that year that it has achieved 90% control.

VII. CERTIFICATIONS

I certify that I am the Designated Representative for the units that are the control units in the Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*		
B. Signature	C. DR ID Number	D. Date Signed

I certify that I am the Designated Representative for the unit identified below that is a transfer unit in the attached Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

~~316~~ 456

G. Enter the proposed total allowance allocation for each year of Phase I, calculated by adding together the reserve allowances for each year indicated in F above and the annual basic allocation in Appendix A or B.

H. Enter the available capacity of this control unit to accommodate transfers of emissions reductions obligations from transfer units for the two years of the extension. This is calculated by subtracting the annual emissions in TPY that would be achieved at 90% control (as defined in ____) from the basic allowance allocation (or the allocation authorized under §72.41 for a substitution unit in an approved substitution plan).

I. You must provide information for the Qualifying Phase I Technology (the 90% control equipment) for this control unit. Complete the following:

1. Describe the control equipment, including:

a. the type of technology;

b. the sulfur dioxide removal efficiency of the design;

c. characteristics of the fuel and range of fuels for which the technology is designed.

For a and c, include additional sheets if necessary. If you use additional sheets, enter "see accompanying documents" in the space on the form.

2. The schedules of compliance including dates for the following increments of progress:

a. Design Engineering (start and complete date)

b. Construction (start and complete dates)

c. Operation (start-up testing and commence dates)

d. Provide a control equipment maintenance schedule

e. Enter the dates of scheduled performance tests, as follows:

(i) Post Combustion Control Technology Start-Up Performance Test - this must be scheduled no later than 90 days after start up of post-combustion QPIT and must be consistent with the requirements of 40 CFR §75.12(c).

(ii) Post Combustion Technology Annual Demonstration - You will be required to conduct a recertification test during each year of Phase I to establish the technology's continuing ability to achieve 90% control, using performance tests in accordance with 40 CFR §75.12(d). The test period must be a 30 day period representing maximum capacity in each calendar year of Phase I, and must post-date the previous year's test by at least 180 days.

You must report the results of these tests with your quarterly emissions monitoring report for the quarters in which the tests were conducted. These tests will serve as demonstration that the technology is able to achieve 90% control. Failure to demonstrate 90% control will have the following consequences: [to be added from 40 CFR §72.42(g)].

J. Monitoring. Mark the appropriate box to indicate the monitoring method.

a. Mark here if the unit will monitor with CEMS at both the outlet and the inlet of the control device in accordance with the requirements of 40 CFR §75.12;

b. Mark here if the unit will request approval for an alternative monitoring method. An alternative may be approvable if the control technology removes SO_2 through a chemical reaction in the combustion process.

II. TRANSFER UNITS

If there are no transfer units involved in this extension plan, put "Not Applicable" in the identification space provided for Transfer Unit Number 1. Otherwise, for each unit:

A. Enter the unit's Acid Rain Program Identification Number found at Appendix A of 40 CFR Part 72.

B. Enter the short name from Part I, Section B of the unit application.

C. Enter the 1988-89 Average Emissions of Sulfur Dioxide, in TPY. This should be calculated using the information filed on EIA form 767 and listed on Appendices A and B (SF# 7231A) and may not exceed the annual TPY that would have resulted from application of the most stringent federally-enforceable allowable emissions rate for those years.

D. Transfer Unit Projections: Enter the appropriate figures for each unit for heat input (in mmBtu), Sulfur Dioxide Emissions Rate (in lbs/mmBtu) and the Sulfur Dioxide Emissions (in TPY) for each year of Phase I; place the information in the spaces corresponding to the numbers in II A. Compute these figures as follows: [to be added, in part from §72.43(e)]

E. For each transfer unit, enter the proposed Phase I Extension Reserve Allowances requested in TPY for 1995 and 1996 calculated as follows: [Note: insert text from 40 CFR §72.42(f)(3)(i) and (ii)] Compute the totals for each year and enter on bottom line.

F. Enter the proposed total allowance allocation (in TPY) for units for each year of Phase I. This is calculated by adding the proposed reserve allowance for each unit to the basic allocation for that unit in Appendix A.

III. EMISSIONS TRANSFER RECONCILIATIONS

In A and B, enter the proposed emissions to be transferred from the transfer units identified in this application including any attachments. This table will accommodate the transfer information for up to four control units and up to five transfer units. You should tabulate your results as follows:

- the total of the emissions being transferred by each transfer unit by adding horizontally along the line. This total should equal the number of reserve allowances requested for that unit;
- the total of the emissions being transferred by all transfer units to any one control unit by adding vertically down the column. This

818458

FORM 7243 AND 7243A

Reduced Utilization Plan

FORM 7243

Reduced Utilization Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

FORM 7243A

Reduced Utilization Plan Verification

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

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Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

II. COMPENSATING UNITS AND INSTALLATIONS (cont.)

C. Sulfur-Free Compensating Installations

	1. AIRS Number	2. Short Name
1		
2		
3		

3. Compensating Generation *(Kwh)*

	1996	1996	1997	1998	1999
1					
2					
3					

D. Required Submissions

The following documents must accompany this plan; if they do not this plan will be incomplete:

1. For all plans designating a compensating unit of any kind:
   a. Documentation that demonstrates that the planned compensating generation will be provided by the units and/or installations identified in II.A., B., and C., above.
   b. Copies of completed Acid Rain Permit Applications (Forms XXXX & XXXX) and Certificates of Representation (Forms XXXX & XXXX) for all affected compensating units that are not located at the same source as the unit identified in Part I of this form.
2. For all plans designating an opt-in unit as a compensating unit, an opt-in plan pursuant to Part 74 for each unit identified in Part II.B. of this form.

III. ENERGY CONSERVATION

A. Description of Energy Conservation Measure(s)

1	
2	
3	

B. Implementation Schedule and Effective Life of Measure *(include additional sheets if necessary)*

1	
2	
3	

C. Energy conservation forecasts *(Energy Savings in Kwh; Heat Input Reduction in mmBtu)*

		1995	1996	1997	1998	1999
1	*Kwh*					
	mmBtu					
2	*Kwh*					
	mmBtu					
3	*Kwh*					
	mmBtu					

Please type or print in the unshaded areas only.

Source ARP ID Number								

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

VII. STANDARD PROVISIONS AND PROHIBITIONS

A. Emissions Limitations

1. Each unit governed by this plan shall hold allowances in its Allowance Tracking System (ATS) compliance subaccount by the allowance transfer deadline that are not less than the unit's Sulfur Dioxide emissions for the calendar year.
2. Each Appendix A unit governed by this plan shall comply with the applicable Nitrogen Oxides emissions limitation of 40 CFR Part 76.

B. Monitoring Requirements

Each unit governed by this plan shall comply with the emissions monitoring plan and emissions monitor certification requirements of 40 CFR Section 72.31(c) and 40 CFR Part 75.

C. Recordkeeping Requirements

Each unit governed by the plan shall comply with the standard recordkeeping requirements of 40 CFR Parts 72-78, and shall maintain at the source all documents, verifications and demonstrations specified in this plan and in 40 CFR Section 72.43.

D. Reporting/Compliance Certification Requirements

1. Each unit governed by the plan shall submit compliance certifications in accordance with 40 CFR Sections 72.400-409.
2. The Designated Representative for each unit in a plan relying on energy conservation or improved unit efficiency measures shall submit annual verification of improved heat rate, reductions in heat input, and energy savings, as specified in 40 CFR Section 72.43(b)(6)(ii) and shall submit all reports required by 40 CFR Section 72.43(b)(6)(ii).
3. The Designated Representative of each unit relying on increased generation at a sulfur-free generation installation or a designated compensating source shall make the demonstration required by 40 CFR Section 72.43(b)(6)(iii).
4. The Designated Representative of the unit identified in Part I of this form shall account for all underutilization at the unit not contemplated by this reduced utilization plan as required by 40 CFR Sections 72.43, 72.402 and 72.409.

E. Prohibitions and Liability

1. It shall be a violation of the Act for the owners, operators, and Designated Representative of any affected unit governed by a reduced utilization plan to operate any such unit except in accordance with the terms of the plan as approved by the Administrator pursuant to this section or to fail to carry out any measure provided for in the plan.
2. It shall be a violation of the Act for any affected source or unit to emit Sulfur Dioxide or Nitrogen Oxides in excess of the emissions limitations provided for in the approved reduced utilization plan unless, in the case of Sulfur Dioxide, the unit has allowances in its ATS compliance subaccount by the allowance transfer deadline not less than the unit's total annual emissions for the year.
3. It shall be a violation of the Act for the owners, operators, and Designated Representative of any Phase I unit that reduces utilization in any calendar year in order to comply with the unit's Phase I emissions reduction obligations under the Acid Rain program to fail to submit a reduced utilization plan in accordance with 40 CFR Section 72.43.
4. The owners, operators, and Designated Representatives of any affected unit named in a reduced utilization plan approved by the Administrator shall be liable for any violation of 40 CFR Part 72 or of the reduced utilization plan.

VIII. CERTIFICATIONS

I certify that I am the designated representative for the unit identified below that is the unit reducing utilization in this reduced utilization plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

I certify that I am the designated representative for the unit identified below that is part of the reduced utilization plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

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1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

Please type or print in the unshaded areas only.

Source ARP ID Number								

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

III. REQUIRED SUBMISSIONS

The following documents must accompany this verification report; if not, this report will be incomplete.

A. The report of an independent auditor that verifies the figures listed in Part II.A. of this form; or,

B. Verification of the figures listed in Part II.A. of this form, certified by the utility regulatory authority of the State in which the unit is located.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments:

_____

_____

III. ENERGY CONSERVATION

A. Describe the Energy Conservation measures that will be used at the original unit to account for the reduced utilization at the original unit.

B. Provide the implementation schedule for and effective life of each measure, as follows: [to be added]

C. For each measure identified, indicate the energy savings, heat rate improvement and heat in reductions forecast for each year of the plan. Enter 'Not Applicable' ('N/A') for those years in which either there is no reduced utilization projected or the conservation measure will not be in effect.

IV. IMPROVED UNIT EFFICIENCY MEASURES

A. Describe the improved unit efficiency measures that will be used at the original unit to account for reduced utilization at the original unit.

B. Provide the implementation schedule for each measure, as follows: [to be added]

C. For each measure identified, indicate the energy savings, heat rate improvement and heat input reductions forecast for each year of the plan. Put 'Not Applicable' ('N/A') for those years in which either there is no reduced utilization projected or the efficiency measure will not be in effect.

V. ACCOUNTING OF REDUCED UTILIZATION

A. Enter the proposed energy savings reductions (in kwh) from Part I C of this form for each year that is applicable.

B. For each year of proposed reduced utilization, enter the projected kwh accounted for by the options listed in the form. Enter the information in the spaces corresponding to parts of the form (e.g., in II A, list the projected kwh to be compensated for by a Phase I affected compensating unit, which is found at Part II A at 3).

C. Add across the line and enter totals for each year.

VI. ACTIVATION AND TERMINATION OF PLAN

A. Indicate either:

- that the plan, if approved, will go into effect on a date certain (enter the date); or
- that the Designated Representative will notify the Administrator of activiation of the approved plan.

B. Enter the date on which the plan will terminate.

VII. STANDARD PROVISIONS AND PROHIBITIONS

No entry is required, but you should read these provisions carefully.

VIII. CERTIFICATIONS

The Designated Representative for the original unit is responsible for distributing the proposed plan to the Designated Representatives for all participating units, and for obtaining the signature for each Designated Representative.

The Designated Representative for the original unit must photocopy the entire form prior to signing it, making enough copies to distribute one each to the Designated Representative for each participating unit. He or she then must sign each copy before distributing them to the Designated Representatives.

The Designated Representatives for the compensating units are responsible for reviewing the application for accuracy, for signing and returning the form to the Designated Representative for the original unit, and for including a copy of the form with the permit application for the compensating unit.

All Designated Representatives who sign this form thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM 7243A
REDUCED UTILIZATION PLAN VERIFICATION
(End of Year Report)

I. UNIT IDENTIFICATION

A. Enter the unit's Acid Rain Program Identification Number, found in Appendix A of 40 CFR Part 72.

B. Enter the short name for the unit given in the unit permit application at Part I, Section B (SF# 7231A).

C. Enter the year for which this report is submitted (i.e., the reporting year).

D. Indicate the parts of the reduced utilization plan that will be verified by this submission. You may check either or both of the boxes.

II. VERIFICATIONS

A. Conservation/Improved Unit Efficiency

1. Provide the improvement in heat rate (in Btu/kwh), reductions in heat input (in mmBtu), and energy savings (in kwh) achieved at the unit between January 1 and September 30 of the reporting year. Heat rate improvement figures are only needed when reporting on improved unit efficiency.

2. Provide an estimate of the improved heat rate, reductions in heat input and energy savings for the 4th quarter of the reporting year (October 1 - December 31). This estimate should be based on the verified savings provided in II A 1 above. Heat rate improvement figures are only needed when reporting on improved unit efficiency.

FORM 7246

NO_x Emissions Averaging Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

FORMS 7247 AND 7247A

NO_x Alternative Emissions Limitation Proposal

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

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FORM 7248

NO_x Deadline Extension

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

FORM 72402

Annual Compliance Certification Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

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II. REPORTING UNIT COMPLIANCE CERTIFICATIONS (cont.)

☐ c. I certify that the unit's [redacted] underutilization caused by a forced outage as reported in Form #XXXX, and that

☐ i. this unit has [redacted] for the underutilization by the demonstration in II.A.4.b., above.

☐ ii. this forced [redacted] will be permanent or prolonged and I herewith submit a compliance plan in accordance with 40 CFR Section 72.43[redacted] designates a compensating unit or installation.

d. I certify that the allowances held in the unit's compliance subaccount as of the allowance transfer deadline:

☐ i. are equal to or greater than the following emissions *(in TPY)* that would have occurred but for the underutilization balance:

☐ ii. are less than the following emissions *(in TPY)* that would have occurred but for the underutilization balance:

TPY

B. Nitrogen Oxides

1. Emissions Limit/Emissions Rate Information:

a. Annual Average Nitrogen Oxide Emissions Rate *(lbs/mmBtu)*	b. Nitrogen Oxide Emissions Limitation *(lbs/mmBtu)*

2. Emissions Certification *(choose one)*:

☐ a. I certify that the Nitrogen Oxide emissions at this unit did not exceed the allowable emissions limitation for this unit for use during the year of this report, as shown by the above information.

☐ b. I certify that the Nitrogen Oxide emissions at this unit did exceed the allowable emissions limitation for this unit for the year of this report, as shown by the above information.

III. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

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1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
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4. Date Notice Sent: _____ By: _____

Comments: _____

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FORMS 72409 AND 72409A

Utilization and Forced Outage Reports

Form 72409

Utilization Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 72409A

Forced Outage Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

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2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments:

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OMB No. XXXX-XXXX
Approval expires X-XX-XX

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1. Date Received: _____

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   a. ☐ Complete ☐ Incomplete

   b. ☐ Approved ☐ Disapproved Explain: _____

   _____

3. Date of Final Approval: _____ By: _____

4. Date Notice Sent: _____ By: _____

Comments:

_____

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within the utility system and units outside of the utility system that have been specifically identified.

'E' is the aggregate under-utilization at all Phase I units in the utility system below their aggregate baseline that is attributable to the system-wide percentage decline in utilization, as calculated pursuant to §72.409(b)(1); and

'F' is the percentage of the total annual Btu's above baseline that is attributable to Phase I units located in the NERC region where the unit that experienced the under-utilization is located, multiplied by the percentage of the utility's generation from units outside of the utility system that have not been specifically identified if using formula (ii), below;

To calculate 'D', use one of the following formulas:

(i) To calculate the NERC Region or sub-region average emissions rate:

[Formula will be added from 40 CFR §72.409]

(ii) To calculate the average emissions rate for the utility system and for any other units outside of the system for which the utility can document it has received generation:

[Formula will be added from 40 CFR §72.409]

where:

'a_i' is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu)

'b_i' is the average annual emissions rate for each unit within the NERC region in lbs/mmBtu

'c_i' is the difference between the annual heat input for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu) and the baseline for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu).

'd_i' is the average annual emissions rate for each unit within the utility system and each specifically identified unit outside of the utility system.

'e' is the % of generation from units outside of the utility system that have not been specifically identified.

'f' is the % of generation from units within the utility system and units outside of the utility system that have been specifically identified.

'n' is the number of units in the NERC region.

'm' is the number of units in the utility system and specifically identified units outside the system providing compensating generation.

IV. CERTIFICATION

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instruction Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM 72049A FORCED OUTAGE REPORT

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. UNIT IDENTIFICATION

A. Enter the unit Acid Rain Program Identification Number.

B. Enter the short name for the unit.

Check the box and attach a copy of the notice of the forced outage that was sent to EPA.

II. OUTAGE INFORMATION

A. Describe the event or events that were responsible for the forced outage, e.g., turbine failure.

B. Indicate the actual or anticipated duration of the outage by:

1. Entering the day the outage began:

2. a. If the outage is over, enter the date the unit returned to full service; or,

b. If the outage is continuing, but expected to end, enter the anticipated date of return to full service; or,

c. If the outage will continue into the following calendar year and the designated representative anticipates that the outage will cause the unit permanently to transfer generation to one or more units that are not otherwise affected during Phase I, you must either

- request a permit revision by submitting a reduced utilization plan designating one or more compensating units; or
- submit a demonstration that it is not possible to restore the unit to service at a reasonable cost. This demonstration can be a utility rate regulatory authority determination or [to be added].

C. Describe the corrective measures the unit operator has taken or will take to correct this outage, including the actual or anticipated date that the measure will be completed or in place. If additional sheets are necessary for a full description, please enter "see accompanying (#) page report" in the space provided.

FORM 7251

Draft Phase I Acid Rain Permit

[Compliance Option] – (SF#_____ attached)
Terms and Conditions:
In addition to the terms and conditions in SF #____, the following terms and conditions shall apply:
[other terms and conditions]

Under the approved alternative method(s) of compliance that are now activated, the permit limits shall be as follows:

Compliance Year	SO_2 Limitation	NO_x Limitation
1995	[#] TPY	[#] (unit)
1996	[#] TPY	[#] (unit)
1997	[#] TPY	[#] (unit)
1998	[#] TPY	[#] (unit)
1999	[#] TPY	[#] (unit)

In the event that the Designated Representative activates a pre-approved alternative compliance plan during the permit term, the limits under that plan shall become the new enforceable limits and, when applicable, shall supersede the limits stated above.

Continuous Emissions Monitoring Requirements

A. The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR Part 75, including:

1. The duty to collect and report emissions data for each unit at the source and to adopt quality assurance procedures and conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR Part 75; and

2. The duty to calculate emissions pursuant to the missing data provisions of 40 CFR Part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required;

B. The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.

C. No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR Part 75, and the unit operates the system in accordance with that approval.

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D. To operate the unit in compliance with the monitoring requirements of 40 CFR Part 75.

E. In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR Part 77; and

F. In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR Part 77 and an approved offset plan as required by 40 CFR Part 77.

Prohibitions

Prohibitions. Any violation of the following prohibitions shall be a violation of the Act and 40 CFR part 72 by the owners, operators and designated representative of the affected unit and/or affected source:

A. No affected unit shall exceed the applicable emissions limitations of 40 CFR Parts 72-78, as follows:

1. No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR Part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.

2. No affected unit shall emit nitrogen oxides in excess of

a. the annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR Part 76; or

b. the superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR Part 72, Subpart D and 40 CFR Part 75;

B. No person shall hold, use, or transfer any allowance except in accordance with Title IV of the Act and the regulations in 40 CFR Parts 72-78.

C. No person shall use an allowance prior to the calendar year for which the allowance was allocated.

D. No person shall make a false statement in any submission required under 40 CFR parts 72-78, inclusive.

Liability

A. Any person who knowingly violates any requirement or prohibition of Title IV of the Act, of 40 CFR Part 72-78, of an Acid Rain permit application filed pursuant to the requirements of Title IV of the Act and 40 CFR Part 72-78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Act.

Definitions

This permit adopts by reference all definitions found in 40 CFR Part 72.

Revisions

(Provisions describing the procedures and limitations applicable to permit revisions will be added consistent with 40 CFR Subpart J.)

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I. INTRODUCTION: THE ACID RAIN PROGRAM

A. General Statutory Background on Acid Rain Regulation

[to be added]

B. Permit Program and Standard Forms

[to be added]

II. TABLE OF CONTENTS FOR INSTRUCTIONS PACKAGE

		Page
	General Instructions	☐
	Glossary of Acid Rain Program Terms Used in the Forms Package	☐
	Forms and Instructions	
*	Designated Representative Certification Forms 72200 and 72200A	☐
	Acid Rain Phase II Permit Application Forms 72000 and 72000A	☐
	Repowering Extension Plan Forms 7244, 7244A, and 7244B	☐
**	NO_x Emissions Averaging Plan Form 7246	☐
**	NO_x Alternative Emissions Limitation Forms 7247 and 7247A	☐
*	Annual Compliance Certification Report Form 72402	☐
*	Excess Emissions Offset Planning Form 772 (Part 77)	☐
*	Excess Emissions Penalty Forms 774 and 774A (Part 77)	☐

* These forms are included in the Phase I Forms Package.

** This form will be included in the Part 76 regulations.

III. GENERAL INSTRUCTIONS

A. Who Must Apply

[to be added]

B. When to File

- The Designated Representative Certification forms must be postmarked no later than midnight **January 1, 1996**. To expedite allowance trading and permit processing, we suggest you submit these forms as early as possible.
- Phase II permit applications including proposed compliance plans must be postmarked no later than midnight, **January 1, 1996.**
- If possible, Acid Rain compliance option forms should be submitted with the permit application. If a compliance plan is submitted after the permit application has been processed, a permit revision may be necessary. Because each compliance option has a specific deadline, a comprehensive list of the final date on which each form may be submitted is provided in Figure 1, below.

FIGURE 1: ACID RAIN COMPLIANCE OPTION FILING DEADLINES

Form Number	Compliance Option Form Name	Deadline
7244	Repowering Extension Proposal Plan	**January 1, 1996**
7244A	Repowering Technology Approval Request	**June 1, 1997**
7244B	Notification of Removal from Operation to Install Repowering Technology	No later than **60 days** prior to removal
7246	NO_x Emissions Averaging Plan	**Any time during Phase II**, as a permit revision
7247	NO_x Alternative Emissions Limitation Proposal	**Any time during Phase II**, as a permit revision
7247A	NO_x Alternative Emissions Limitation Proposal: Application for Final Limitation	No later than **90 days** before end of demonstration period

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State Air Pollution Agencies

State of **Alabama**, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.
State of **Arizona**, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.
State of **Arkansas**, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.
State of **California**, Air Resources Board, 1102 Q Street, Sacramento, California 95814.
State of **Colorado**, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.
State of **Connecticut**, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.
State of **Delaware**, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.
District of Columbia, Department of Consumer and Regulatory Affairs, 5000 Overlook Avenue S.W., Washington D.C. 20032.
State of **Florida**, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.
State of **Georgia**, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.
State of **Idaho**, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.
State of **Illinois**, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.
State of **Indiana**, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206
State of **Iowa**, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.
State of **Kansas**, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.
State of **Kentucky**, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.
State of **Louisiana**, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.
State of **Maine**, Department of Environmental Protection, State House, Augusta, Maine 04330.
State of **Maryland**, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.
Commonwealth of **Massachusetts**, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.
State of **Michigan**, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.
State of **Minnesota**, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.
State of **Mississippi**, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.
State of **Missouri**, Department of Natural Resources, P.O. Box 1368, Jefferson City, Missouri 65101.
State of **Montana**, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.
State of **Nebraska**, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.
State of **Nevada**, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.
State of **New Hampshire**, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.
State of **New Jersey**, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.
State of **New Mexico**, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.
State of **New York**, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, Albany, New York 12233.
State of **North Carolina**, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.
State of **North Dakota**, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.
State of **Ohio**, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.
State of **Oklahoma**, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.
State of **Oregon**, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.
Commonwealth of **Pennsylvania**, Department of Environmental Resources, 105 S. Second Street, P.O. BOX 2357, Harrisburg, Pennsylvania 17120.
State of **Rhode Island**, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.
State of **South Carolina**, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.
State of **Tennessee**, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.
State of **Texas**, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.
State of **Utah**, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.
State of **Vermont**, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.
Commonwealth of **Virginia**, Virginia State Air Pollution Board, Room 1106, Ninth Street Office Building, Richmond, Virginia 23219.
State of **Washington**, Department of Ecology, Olympia, Washington 98504.
State of **West Virginia**, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.
State of **Wisconsin**, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

GLOSSARY OF ACID RAIN PROGRAM TERMS

[to be added]

DRAFT 72200

Date 10/21/91

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Application for Phase II Acid Rain Permit
(Source Information)

Follow instructions for Form 72200.

I. SOURCE IDENTIFICATION

A. Source Name and Mailing Address

1. Source Name

2. Street or P.O. Box

3. City | 4. State | 5. Zip

B. Source Location

1. Street, Route Number or Other Specific Identifier

2. City | 3. State | 4. Zip

5. County Name | 6. Phone *(area code & number)*

C. Other Source Information

1. Operating Company

2. NERC Region | 3. Aggregate Baseline *(mmBtu)*

II. UNIT IDENTIFICATION

A. Appendix B Units

If more than 4 units, copy this sheet and enter number of copies here ⟶

1. Unit Name

1

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

2

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

3

2. Short Name | 3. Unit ARP ID Number

1. Unit Name

4

2. Short Name | 3. Unit ARP ID Number

Source ARP ID Number

Please type or print in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

IV. STANDARD PROVISIONS & PROHIBITIONS (cont.)

3. Liability
   a. Any person who knowingly violates any requirement or prohibition of Title IV of the Act, of 40 CFR Parts 72-78, of an Acid Rain permit application filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Act.
   b. All owners, operators, and designated representatives of any affected units governed by a multi-unit compliance plan that is filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78 shall be liable for any violation of the plan at any unit governed by the compliance plan, including liability for failure to fulfill the obligations specified in 40 CFR Part 77 and Section 411 of the Act.
   c. Any person who knowingly makes a false material statement in any record, submission, or report required by the Acid Rain program shall be subject to criminal enforcement pursuant to Section 113(c) of the Act and 18 U.S.C. 1001.
   d. No permit revision shall excuse past noncompliance.

B. Standard Provisions

1. Continuous Emissions Monitoring Requirements
   a. The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR Part 75, including:
      i. The duty to collect and report emissions data for each unit at the source, to adopt quality assurance procedures, and to conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR Part 75; and,
      ii. The duty to calculate emissions pursuant to the missing data provisions of 40 CFR Part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required.
   b. The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.
   c. No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR Part 75, and the unit operates the system in accordance with that approval.

2. Recordkeeping and Reporting Requirements
   a. The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application.
      i. The certificate of representation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR Part 72, Subpart B;
      ii. All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR Part 75;
      iii. Copies of all reports required by 40 CFR Parts 72-78; and,
      iv. Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.
   b. The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR Part 72 Subpart K and other provisions of 40 CFR Parts 72-78.

3. Allowance Information
   a. An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of Title IV of the Act and 40 CFR Parts 72-78. Nothing in Title IV, in 40 CFR Parts 72-78, in this permit application or in any provision of law shall be construed to limit the authority of the United States to terminate or limit the authorization.
   b. An allowance allocated by the Administrator under the Acid Rain program does not constitute a property right.

4. Effect on Other Authorities
   a. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by a unit shall not affect the applicability of, or the affected source's obligation to comply with, any other provision of the Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.
   b. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges, or as affecting any State law regarding such State regulation, or as limiting such State regulation, including any prudence review requirements under such a State law.
   c. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.
   d. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

5. Definitions. This application adopts by reference all definitions found at 40 CFR Part 72.

V. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative	
B. Signature	C. Date Signed

DRAFT 72200A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number												

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Application for Phase II Acid Rain Permit
(Unit Information)

Follow Instructions for Form 72200A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name

C. This unit is *(mark all that are applicable)*:

- ☐ 1. Existing
- ☐ 2. Opt-in
- ☐ 3. New
- ☐ 4. Coal-fired *(complete I.D., below)*
- ☐ 5. Part of a common stack *(attach Form #XXXX)*
- ☐ 6. Multi-header

D. The boiler type(s) at this unit is(are):

	Emissions Limits
☐ 1. Tangentially fired	TBA
☐ 2. Dry bottom wall-fired	TBA
☐ 3. Not applying cell burner technology	TBA
☐ 4. Wet bottom wall-fired	TBA
☐ 5. Cyclone	TBA
☐ 6. Applying cell burner technology	TBA
☐ 7. Other *(describe)*:	

a.	
b.	
c.	

II. EMISSIONS LIMITATIONS

A. Sulfur Dioxide

- ☐ 1. This unit proposes to receive the following Phase II Allowance Allocation during the permit term *(TPY)*: →
- ☐ 2. If approved, a repowering plan will govern the emissions limits.
- ☐ 3. This new unit will be subject to the emissions limits listed in Part III, below.
- ☐ 4. This opt-in unit will be subject to the emissions limits established in 40 CFR Part XX *(attach Form #XXXX)*.

B. Nitrogen Oxides

- ☐ 1. This unit proposes to meet the emissions limit(s) based on the boiler type(s) identified above.
- ☐ 2. This unit proposes an alternative emissions limit *(see Part IV, below, and attached compliance plan forms)*.
- ☐ 3. Nitrogen Oxides emissions limitations information is not available at this time. Complete Nitrogen Oxides compliance information will be submitted no later than January 1, 1998 on an amended copy of this form.

III. NEW UNIT EMISSIONS LIMITATIONS

- ☐ A. This new unit is specified in Part 73 as eligible for a Phase II Allocation. The allocation for this unit is *(TPY)*:
- ☐ B. This new unit is not specified in Part 73 and has the following characteristics:
  - 1. Annual fuel consumption *(mmBtu)*: →
  - 2. Allowable Sulfur Dioxide emissions rate *(lbs/mmBtu)*: →
- C. This new unit commenced/will commence operation on *(mm/dd/yy)*: →

FORMS #72200 and 72200A
APPLICATION FOR PHASE II ACID RAIN PERMIT

[Note: We anticipate that, in light of experience with Phase I permitting and the needs of State Programs, the forms and these instructions will be revised substantially prior to the time of actual implementation of Phase II.]

INTRODUCTION

Clean Air Act Section 408 and the regulations implementing that section at 40 CFR Part 72 establish a permit program for affected sources under the Acid Rain Program. Subpart C of those regulations, 40 CFR §§72.30 et seq. sets forth the requirements for and contents of Acid Rain permit applications and compliance plans.

In Phase II the Designated Representative for each Phase II affected source must submit a permit application and compliance plan for that source. These will include sources with units listed on Appendix B, new units and opt-in units. When a given source consists of more than one unit, the Designated Representative must file a compliance plan for the source (or "facility") that covers all such units. However, for each unit, the Designated Representative must demonstrate individual compliance with the applicable Acid Rain Program limits.

The permit application forms are designed to accommodate both of these requirements. For each source that the Designated Representative represents, he or she will submit source-identifying information on SF# 72200. The Designated Representative also must submit a unit application on SF# 72200A that will state the limits for the unit and will indicate how the unit will comply with those limits. For a unit that plans an Acid Rain compliance option, (e.g., repowering, NO_x emissions averaging) the Designated Representative also will be required to complete the form or forms designed to allow the applicant to demonstrate compliance through any such compliance option. Instructions for those compliance options forms accompany the individual forms. The source information form, the application forms for the units at the source and attached compliance options forms constitute the "Source Compliance Plan."

The statute and regulations provide that the permit application and compliance plan shall be binding on the owner, operator and Designated Representative of the unit and shall be enforceable in lieu of a permit until the permitting authority issues a permit to the source. Permit applications are due for all Phase II affected sources (except new units; see Section II of the general Instructions for "Who Must Apply") on **January 1, 1996.**

INSTRUCTIONS FOR FORM 72200
APPLICATION FOR PHASE II ACID RAIN PERMIT
(SOURCE INFORMATION)

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. SOURCE INFORMATION

A. Name: Provide the name of the source or facility for which this application is filed. This name will include the company name and a name for the source, e.g., "ABC Utility Electric Power Station."

B. Location:

1-4. Provide a descriptive address for the source; if there is no street address or route number, give the most accurate alternative geographic information (e.g., "Intersection of Rts. 6 and 502" or the section number from county records). If the location is the same as the address given in I A, above, enter "Same as above" on line 1, and skip to 5, below.

5. List the county in which the source is located.

6. Provide the main phone number for the source.

II. UNIT IDENTIFICATION

List the affected units. Provide information for Appendix B units in Section A. In Section B, list only those non-Appendix B units that you will be proposing as part of an alternative compliance plan. (You will need to complete a SF# 72200A for each of the units you list.) For each unit provide the following:

1. Fill in the name of the affected unit (e.g., "ABC Elect. Gen. Unit #4.")

2. Give a short name that is commonly used or could be used as an easy identification of the unit (e.g., "ABC #4.")

3. Provide the Acid Rain Program Identification Number for the unit. This is the source number, which appears at the top center of the first page of this form, plus three digits that identify the unit (e.g., "004"). Enter the three digits in the space provided. (Acid Rain Program Identification Numbers are listed in Appendix B.)

III. CERTIFICATE OF REPRESENTATION

Mark this box to indicate you are submitting the original or a copy of the Certificate of Representation for this source.

IV. STANDARD PROVISIONS AND PROHIBITIONS

These provisions and prohibitions apply to all Acid Rain permit applications and proposed compliance plans, which are binding until the permitting authority either makes an initial permitting decision or disapproves the application. These provisions attach to the source and to all affected units that are a part of that source.

V. CERTIFICATION

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

A. SO_2 Compliance Plan

All units must hold sufficient allowances.

1. Mark here if the unit will achieve compliance through allowances by the Phase II deadline (1/1/2000).

2. Mark here if the unit seeks an extension on the deadline for meeting the SO_2 limits through a repowering plan, and further indicate

a. if the repowering technology has been certified (attach copy), or

b. if the repowering technology has not yet been certified.

B. NO_x Compliance Plan

All coal-fired units are regulated in Phase II and are required to meet Title IV NO_x emissions limits by 2000. A unit can apply for alternative limits or can apply for an extension of the limits under NO_x compliance options.

a. Mark this box if you plan to meet the regulatory emissions limit that applies to the boiler or boilers at your unit, as listed in Part II, Section B of this unit application.

b. Mark this box if the unit seeks approval for one or more of the compliance options. Indicate the options for which approval is sought by marking the appropriate box(es):

i. **Emissions Averaging:** Clean Air Act Section 407(e) and the regulations implementing that Part at 40 CFR §72.46, allows the Designated Representative of two or more units subject to the Title IV emissions limit to submit a proposal to set alternative contemporaneous annual emissions limits for the units. These new limits must assure that the resulting emissions will be no greater than they would have been had the statutory limits been applied at each unit. A more complete description of this provision and of the components of the plan will be included in 40 CFR Part 76.

ii. **Alternative Emissions Limit:** Clean Air Act Section 407(d) and the regulations implementing that Section at 40 CFR §72.47 allow the Administrator to authorize an alternative NO_x emissions limit for a unit that can adequately demonstrate its inability to meet the limit using NO_x low burner technology. A more complete description of this provision and of the components of the plan will be included in 40 CFR Part 76.

V. MONITORING PLAN

Clean Air Act Section 412 requires that all units that are subject to Title IV permitting requirements monitor sulfur dioxide, nitrogen oxides, opacity and volumetric flow using Continuous Emission Monitors (CEMS) or an alternative monitoring system that is demonstrated to provide data to that provided by a CEMS. The unit also must submit a monitoring plan on SF# [7510].

Indicate the status of the monitoring plan by checking the appropriate box.

VI. STANDARD PROVISIONS AND PROHIBITIONS

The standard provisions and prohibitions listed in the source application form are incorporated by reference into this unit application and apply with full force and effect to this unit.

VII. CERTIFICATION

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

DRAFT 7244
Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number			

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Repowering Extension Plan Proposal (Single Unit Plan)

Follow instructions for Form 7244.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name

	SIP Limit	1995 Actual
C. Sulfur Dioxide Emissions Rate		

D. The above identified unit will be:
- ☐ 1. Repowered
- ☐ 2. Replaced with a repowered unit *(complete I.E. below)*

E. If the unit identified above will be replaced with a repowered unit, identify the repowered unit:

1. Unit ARP ID Number	2. Short Name

II. REPOWERING PROPOSAL

A. Identify the repowering technology that will be used at the repowered unit:

- ☐ 1. Atmospheric fluidized bed combustion
- ☐ 2. Pressurized fluidized bed combustion
- ☐ 3. Integrated gasification combined cycle
- ☐ 4. Magnetohydrodynamics
- ☐ 5. Integrated gasification fuel cells
- ☐ 6. Direct coal-fired turbine
- ☐ 7. Indirect coal-fired turbine
- ☐ 8. Other qualified repowering technology *(complete II.B., below)*

B. For all technologies, indicate status of technology certification:

- ☐ 1. This repowering technology has been certified *(documentation is included)*.
- ☐ 2. Certification for this repowering technology is pending.

III. ACTIVATION OF PLAN

Mark the appropriate box:

- ☐ A. This plan will go into effect upon approval.
- ☐ B. This plan is contingent. The applicant will notify the Administrator no later than December 31, 1997 of a decision to activate the plan.

IV. REPOWERING COMPLIANCE SCHEDULE

A. Complete design engineering *(mm/dd/yy)*	
B. Remove unit from operation to install qualified repowering technology *(mm/dd/yy)*	
C. Start construction *(mm/dd/yy)*	
D. Complete construction *(mm/dd/yy)*	
E. Start-up testing *(mm/dd/yy)*	
F. Commence commercial operation *(mm/dd/yy)*	
G. (For replaced units) Permanent shut-down date for existing unit *(mm/dd/yy)*	

Please print or type in the unshaded areas only.

Source ARP ID Number			

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

DRAFT 7244B
Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Notification of Removal from Operation to Install Repowering Technology (Single Unit Report)

Follow Instructions for Form 7244B.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name

II. NOTIFICATION

☐ A. The unit identified above will be removed from operation for installation of repowering technology on *(mm/dd/yy)*:

☐ B. The unit identified above will be removed from operation permanently on *(mm/dd/yy)*: ⟶

III. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. The annual Sulfur Dioxide emissions beginning on the date of removal of the unit from operation to install the repowering technology or of permanent shutdown for replacement shall not exceed the allowances held in the unit's Allowance Tracking System (ATS) compliance sub-account by the allowance transfer deadline.
2. Any unit with an approved repowering extension shall not emit Nitrogen Oxides in excess of the applicable limitation in the attached permit application for that unit beginning on the date that the unit will be shut down for repowering or permanently shut down for replacement.
3. In no event shall any unit governed by a repowering extension plan be excused from compliance with any other requirement of the Act, including any NAAQS requirement, any SIP requirement, or any NSPS.

B. Test Methods

Test methods shall be those indicated in the attached permit application.

C. Reporting/Compliance Certification Requirements

1. Not later than 60 days after the repowered unit commences operation at full load, the Designated Representative shall submit a report comparing actual hourly emissions of any pollutant regulated under the Act at the repowered unit and at the existing unit prior to repowering.
2. The Designated Representative shall provide written notice to the permitting authority within 10 days of any deviations from this repowering plan.
3. The Designated Representative shall provide written notice 60 days prior to any proposed revision in a scheduled increment of progress.
4. Should the technology, demonstration or information requirements of 40 CFR Section 72.44 not be met, the approved repowering extension shall be deemed null and void.

D. Prohibitions

1. It shall be a violation of the Act to transfer any allowances allocated to a unit granted a repowering extension during the extension period.
2. The Designated Representative shall not replace an existing unit with a repowered unit unless the following conditions are met:
   a. the replacement unit shall have the same Designated Representative as the replaced unit;
   b. the replacement unit shall replace the existing unit; and,
   c. the existing unit shall be retired from service on or before the date the replacement unit commences commercial operation.
3. Beginning in the year 2000 it shall be a violation of the Act for the Designated Representative, owner, or operator of a repowered unit to fail to comply with the requirements of this section, or of any other regulations or permit requirements implementing this section.
4. Should the technology, demonstration, or information requirements of this section not be met, the approved repowering extension shall be deemed null and void.
5. No repowering extension plan shall be terminated after December 31, 1999. The Designated Representative for a repowering unit, however, may withdraw and terminate the repowering extension plan at any time prior to December 31, 1999, using the administrative permit amendment procedures set forth at 40 CFR §72.303.
6. Any unit that is granted an extension under this section shall not be eligible for a waiver under Section 111(j) of the Act.
7. No new unit that is designated as a replacement unit for an existing unit qualifying for an extension under this section and that is located at a different site than the existing unit shall receive an exemption from the requirements imposed under Title I of the Act, including Section 111 of the Act.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	
B. Signature	C. Date Signed

FORMS #7244, 7244A and 7244B
REPOWERING EXTENSION PLAN FORMS

Clean Air Act §409 and the regulations implementing that section at 40 CFR §72.44 provide that an existing unit may be granted an extension of its Phase II Acid Rain emissions limitations from January 1, 2000 to December 31, 2003. Units that are eligible to apply for a repowering extension are existing coal-fired or oil fired utility units that had an actual 1985 sulfur dioxide emissions rate equal or greater than 1.2 lbs/mmBtu. To qualify for such an extension, the Designated Representative for the unit must demonstrate that the unit will be repowered with qualifying clean coal technology, or will be replaced by a new unit that uses such repowering technology.

INSTRUCTIONS FOR FORM #7244
REPOWERING EXTENSION PLAN PROPOSAL

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. UNIT IDENTIFICATION

A and B. Enter the Acid Rain Program Identification Number and the unit's short name from Part I, Sections A and B of the unit's permit application (SF# 72200A).

C. Emissions Data

Enter SO_2 emissions limitations information for the unit, including the SIP limit and the 1995 actual emissions rate.

D. Indicate whether the unit will be repowered or replaced with a repowered unit.

E. If the unit will be replaced, for the proposed replacement unit

1. Enter the Acid Rain Program Identification Number.

2. Enter the unit's short name from Part I, Section B of the replacement unit's permit application (SF# 72200A).

II. REPOWERING PROPOSAL

A. Identify the repowering technology that will be used at the repowered unit. If your technology is not listed at II A (1)-(5), mark (6).

B. For all technologies, indicate the status of the technology certification.

III. ACTIVATION OF PLAN

Mark the appropriate box to indicate whether you want the plan to go into effect upon approval, or whether you want to have the plan remain contingent. If you do not notify the Administrator by December 31, 1997 of a decision to activate the plan, the plan will be null and void after that date.

IV. REPOWERING COMPLIANCE SCHEDULE

Indicate the proposed dates for the listed increments of progress for the unit that will be repowered.

V. STANDARD PROVISIONS AND PROHIBITIONS

Section V of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

VI. CERTIFICATIONS

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM #7244A
REPOWERING TECHNOLOGY APPROVAL REQUEST

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. UNIT IDENTIFICATION

A and B. Enter the Acid Rain Program Identification Number and short name from Part I, Sections A and B of the unit permit application.

C. Indicate whether the unit will be repowered or replaced with a repowered unit.

D. If the unit will be replaced, for the proposed replacement unit, enter the Acid Rain Program Identification Number and the unit's short name from Part I, Sections A and B of the replacement unit's permit application (SF# 72200).

II. REPOWERING PROPOSAL

A. Identify the repowering technology that will be used at the repowered unit. If the proposed technology is a qualified derivative of one of the technologies listed in (1)-(5), mark the box at 6, fill in

the number of the listed technology, and complete part II C. If your technology is not listed at II A (1)-(6), mark (7) and complete II C.

B. Mark this if you have marked (1)-(5) on the form, and attach the required vendor guarantee.

C. Mark this if you have marked (6) or (7) above, and attach the required vendor guarantee.

III. STANDARD PROVISIONS AND PROHIBITIONS

Section III of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

IV. CERTIFICATIONS

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM #7244B NOTIFICATION OF REMOVAL FROM OPERATION TO INSTALL REPOWERING TECHNOLOGY

The Designated Representative must submit this form to EPA at least 60 days in advance of the date on which the affected unit that has been granted an extension is to be removed from operation to install the repowering technology.

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. UNIT IDENTIFICATION

A and B. Enter the Acid Rain Program Identification Number and the unit's short name from Part I, Sections A and B of the unit permit application.

II. NOTIFICATION

Provide the dates that the unit identified in Part I will be removed from operation for installation of repowering technology or for permanent shutdown in the case of replacement with a new unit.

III. STANDARD PROVISIONS AND PROHIBITIONS

Section III of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

IV. CERTIFICATIONS

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

PART 73 -- SULFUR DIOXIDE ALLOWANCE SYSTEM

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APPENDIX A TO PART 73 - Allowance System Forms

APPENDIX B TO SUBPART F - List of Qualified Energy Conservation Measures

Authority: 42 U.S.C. 7651

Subpart A -- Background and Summary

§73.1 Purpose

The purpose of this Part is to establish the requirements and procedures for the following:

(a) the allocation of sulfur dioxide emissions allowances;

(b) the tracking, holding, and transfer of allowances;

(c) the use of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to Part 72 and Part 77;

(d) the sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program;

(e) the application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve; and

(f) the qualifying measures and validation procedures for reduced utilization plans under Part 72, §72.43.

§73.2 Applicability

The following parties shall be subject to the provisions of this Part:

(a) owners, operators, and designated representatives of sources deemed affected pursuant to §72.7;

(b) any new independent power producer as defined in §416 of the Act and this Part, except as provided in §405(g)(6) of the Act;

(c) any owner of an affected unit who may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program established in §404(f) of the Act;

(d) any small diesel refinery as defined in this Part, and (e) any other person, as defined in this Part, who chooses to purchase, hold, or trade allowances as provided in §403(b) of the Act.

§73.3 Definitions

The terms used in this Part shall have the meaning given in the Act, as interpreted by this Part and to CFR Parts 73-78, and in this section as follows:

Account number means the identification number given to each allowance tracking system account pursuant to §73.31(d).

Acid Rain Program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to Title IV of the Act under 40 CFR Parts 72-78.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Affected unit means a unit, or a source that opts in under 40 CFR Part 74, that is subject to any emission reduction requirement or limitation under the Acid Rain Program.

Allowance means an authorization, allocated by the Administrator under the Acid Rain program, to emit up to one ton of sulfur dioxide, during or after a specified calendar year.

Allowance Tracking System means the system by which the Administrator allocates, issues, records, and tracks allowances.

Allowance Tracking System account means an account in the Allowance Tracking System established by the Administrator for the purposes of allocating, holding, transferring, and using allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, and is the last day on which

allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Alternate authorized account representative means the natural person designated in a certificate of representation submitted by an authorized account representative in accordance with Subpart B of Part 72 in the case of a unit account, or §73.33 in the case of a non-unit account, to act on behalf of the authorized account representative with regard to all matters within the authority of the authorized account representative under this Part.

Authorized account representative means a natural person who may transfer and otherwise dispose of allowances held in an account in the Allowance Tracking System, including, in the case of a unit account, the designated representative of the owners and operators of an affected unit.

Certifying official, for purposes of Part 73, means:

(a) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation;

(b) For a partnership or sole proprietorship, a general partner or the proprietor, respectively; and

(c) For a local government entity or, State, Federal, or other public agency, either a principal executive officer or ranking elected official.

Compliance subaccount means an affected unit's Allowance Tracking System subaccount in which are held, (a) from the date that allowances usable in the current calendar year are recorded under §73.34(a) through December 31, allowances that may be used for compliance for the current calendar year and, (b) after December 31 until the date that deductions are made under §73.35(b), allowances that may be used for compliance for the preceding calendar year.

Compliance use date means the first calendar year for which an allowance may be used for purposes of meeting a unit's sulfur dioxide emissions limitation requirements.

Current year subaccount means the subaccount in an Allowance Tracking System non-unit account in which are held allowances that may be transferred for the purpose of meeting a unit's sulfur dioxide emissions limitation requirements in the current calendar year until December 31, and after December 31 until the date that deductions are made under §73.35(b), for the purpose of meeting such requirements in the preceding year.

Customer means a purchaser of electricity not for purposes of transmission or resale.

Demand-side measures means measures to improve the efficiency of consumption of electricity by customers of an electric utility and includes the resources set forth in Appendix B(1) of this Part.

Designated representative means a natural person authorized by the owners and operators of a source and of all affected units at the sources, as evidenced by a certificate of representation submitted in accordance with 40 CFR Part 72, Subpart B to represent and legally bind the owners and operators jointly and severally as a matter of federal law in all matters pertaining to the Acid Rain Program. Whenever the term

"responsible official" is used in 40 CFR Part 70 or 71 or in a State operating permit program approved pursuant to Title V of the Act and 40 CFR Part 70, it shall be deemed to refer to the "designated representative" as defined here in so far as Acid Rain Program actions, standards, requirements, or prohibitions are concerned.

Electric Utility means any person, State agency, or Federal agency that sells electric energy.

EPA Conservation Verification Protocol means a methodology developed by the Administrator pursuant to §73.82(c) to be used in calculating the electricity saved from energy conservation and improved unit efficiency measures for the purposes of Title IV of the Act.

Existing affected unit, means, for purposes of Part 73, a unit that is both an affected unit and an existing unit, as defined in this Part.

Existing unit, means a unit (including a unit subject to §111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990 and that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an existing unit. Existing units do not include simple combustion turbines, or units that serve only a generator with a nameplate capacity of 25 MWe or less.

First-in, first-out accounting basis, or FIFO, means the following order for the purposes of allowance deductions pursuant to §73.35(b):

(1) Allowances originally allocated for the unit and recorded in the unit's compliance subaccount pursuant to Subpart C of this Part, beginning with those with the earliest compliance use date, and followed by

(2) Those allowances allocated for other units and recorded in the unit's compliance subaccount pursuant to Subpart D, beginning with those with the earliest date of recordation.

Future year subaccount means a subaccount in an Allowance Tracking System account in which allowances are held for one of the 30 years following the later of 1995 or a current calendar year following 1995.

Hybrid generating facility means a plant that generates electricity using a combination of renewable energy (wind, solar, biomass, or geothermal) and non-renewable energy resources.

Least cost plan means a least cost energy conservation and electric power planning methodology employed by an electric utility that evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost. These resources include but are not limited to, new power supplies, energy conservation, load management, and renewable energy resources.

Load management means economic reduction of electric energy demand during a utility's peak generating periods.

Net income neutrality means, in the case of energy conservation measures undertaken by an electric utility whose rates are regulated by a State regulatory authority, rates and charges established by the State regulatory authority that ensure that the net income earned by the utility on the book value of its State-jurisdictional equity investment will be no lower as a consequence of its expenditures on qualified cost-

effective energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures.

Non-unit account means an Allowance Tracking System account that is not a unit account.

Period of applicability means the period on or after January 1, 1992 and before the earlier of:

(1) December 31, 2000, or

(2) The date on which any unit that is owned or operated by an electric utility becomes an affected unit.

Person means an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

Process source shall have the meaning provided in 40 CFR Part 74.

Receive or *receipt of* means the coming into possession of a request or notification transmitted by certified United States Mail, with the indication of its official postmark, or by other means, with an equivalent official time and date mark to indicate the time of dispatch and a record of delivery.

Recordation means the official deposit or withdrawal of allowances, by the Administrator, in or from an account or subaccount in the Allowance Tracking System.

Reduced utilization means a reduction, during any calendar year during Phase I, in the annual average heat input at an affected unit, below the unit's baseline, where such reduction subjects the unit to the requirements of §72.43.

Renewable energy input means the quantity of biomass, solar, geothermal, or wind resources (in Btu's) consumed in the process of generating electricity (in kilowatt hours).

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Serial number means the unique identification number assigned to each allowance by the Administrator, pursuant to §73.34(d).

Small diesel refinery (reserved)

State regulatory authority means a state-based authority or commission responsible for oversight of the operations of electric utilities, including, but not limited to, rates and charges to customers.

Submit means to send or to transmit information or correspondence in writing by certified United States Mail, with the indication of its official postmark, or by other means, with an equivalent official time and date mark to indicate the time of dispatch and a record of delivery.

Supply-side measures means measures to improve the efficiency of activities or facilities used by an electric utility to provide electricity to its customers and includes the measures set forth in Appendix B(2) of this Part.

Sulfur dioxide emissions limitation requirements means the limitation on sulfur dioxide emissions specified for an affected unit in §403, §404, or §405 of the Act or in the unit's permit.

Transferee account means the Allowance Tracking System account to which allowances are being transferred.

Transferror account means the Allowance Tracking System account from which allowances are being transferred.

Transferror unit account means a unit account that is a transferror account.

Unit account means an Allowance Tracking System account that is established for an affected unit.

Use of allowances means the deduction and consumption of allowances to offset sulfur dioxide emissions in compliance with sulfur dioxide emissions limitation requirements.

§73.4 Deadlines

In any year in which the deadline for an action authorized or required under this Part falls on a non-business day, the deadline will be the first business day after the date stated in this Part.

Subpart B -- Allowance Allocations

§73.11 - §73.29 Allowance Calculations and Tables [Reserved]

Subpart C -- Allowance Tracking System

§73.30 Allowance Tracking System Accounts

(a) *Nature and function of unit accounts.* The Administrator will establish accounts for all affected units pursuant to §73.31 (a) and (b) and Part 74. All allocations of allowances pursuant to Subparts A and E and Parts 72 and 74, transfers of allowances made pursuant to Subparts C and D, and deductions of allowances made for purposes of offsetting emissions pursuant to §73.35 (b) and (f) and Part 77 will be recorded in the unit's Allowance Tracking System account.

(b) *Nature and function of non-unit accounts.* Transfers of allowances held for any person other than an affected unit, made pursuant to Subparts C, D, E, and F, will be recorded in that person's Allowance Tracking System account established pursuant to §73.31(c).

§73.31 Establishment of Accounts

(a) *Existing affected units.*

(1) Not later than January 30, 1993, the Administrator will establish an Allowance Tracking System account for each unit that is, or will become, an existing affected unit pursuant to §404(a) or §405 of the Act;

(2) (i) For units that become affected units pursuant to §404(b), §404(c), and §408(c)(1)(B) of the Act and §72.42 and §72.43, the Administrator will establish unit accounts pursuant to §72.42 and §72.43; and

(ii) For sources that become affected units pursuant to §72.49 and Part 74, the

Administrator will establish a unit account for each unit.

(b) *New units.* Upon receipt of a valid certificate of representation for a new unit pursuant to Part 72, the Administrator will establish an Allowance Tracking System account for the unit.

(c) *Non-unit accounts.*

(1) Any person may apply to open an Allowance Tracking System account for the purpose of holding and transferring allowances. Such application shall be submitted to the Administrator by means of the New Account/New Authorized Account Representative Form, in Appendix A of this Part, which will include, at a minimum:

(i) Name and title of the authorized account representative pursuant to §73.33;

(ii) Mailing address, telephone number and facsimile transmission number, if any, of the authorized account representative;

(iii) Organization or company name (if applicable) and type of organization (if applicable); and

(iv) Certification by the authorized account representative pursuant to §73.33(c).

(2) Upon receipt of such application, the Administrator will establish an Allowance Tracking System account for the person identified in the application pursuant to §73.33(b) and (c).

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established pursuant to this section.

§73.32 Allowance Account Contents

Each allowance account will include, at a minimum, the following:

(a) The name, address, telephone number and facsimile transmission number, if any, of the authorized account representative and, in the case of a unit account, a list of all persons identified as owners of record in §72.20(c)(4), or, in the case of a non-unit account, a list of all persons with an ownership interest identified in §73.33(c)(1);

(b) A list of all transfers of allowances to, and from, the account, including the identity of the transferror and transferee accounts;

(c) In the case of a unit account for an existing affected unit, beginning in 1995, a compliance subaccount;

(d) In the case of a unit account for a new unit, a compliance subaccount;

(e) In the case of a non-unit account, a current year subaccount;

(f) Future year subaccounts for each of the 30 calendar years following the later of 1995 or the current calendar year;

(g) In the case of a unit account, the current total of sulfur dioxide emissions in tons for the current calendar year as reported to date pursuant to Part 75.

§73.33 Authorized Account Representative

Following the establishment of an Allowance Tracking System account, all matters pertaining to the account, including, but not limited to, the use and transfer of allowances in the account, shall be undertaken only by the authorized account

representative.

(a) *Unit accounts*. For purposes of accounts for affected units, the authorized account representative shall be the designated representative for the unit certified pursuant to §72.20 and shall be subject to the requirements of Subpart B of Part 72.

(b) *Non-unit accounts*. For purposes of a non-unit account, the authorized account representative shall be the person authorized in the application for opening the account submitted pursuant to §73.31(c), which may be modified pursuant to paragraph (e) of this section.

(c) *Certificate of representation for the authorized account representative*. No allowance transfers will be recorded for a non-unit account until the authorized account representative has signed a certificate of representation on the New Account/New Authorized Account Representative Form and the Administrator has established the new account. The certificate of representation shall include:

(1) A list of all persons with an ownership interest with respect to the allowances held in the non-unit account and which shall be amended and resubmitted within 30 days following any transaction giving rise to any change of ownership interest, by means of a New Account/New Authorized Account Representative Form;

(2) A statement that the representative was selected by an agreement binding on all persons who have an ownership interest with respect to the allowances held in the non-unit account that includes a specification of the terms and conditions under which an alternate authorized account representative, if any, is to act in place of the authorized account representative;

(3) A statement that the authorized account representative has all necessary authority to carry out the duties and responsibilities of the authorized account representative as enumerated in this Part;

(4) A statement that the authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the binding agreement.

Where only one person has ownership interest with respect to the allowances in an account, the certification shall state that all allowances in the account are deemed to be held for that person.

(d) *Alternate authorized account representative*. For a non-unit account, the certificate of representation may designate one alternate authorized account representative to act on behalf of the certifying authorized account representative in the event the authorized account representative is absent or otherwise not available to perform actions or duties specified in this Part. The alternate shall be a natural person and shall be authorized provided that: the conditions and procedures of the certificate of representation, specified in subsection (c) are met, and:

(1) In the event of a conflict, any action taken or submission made by the authorized account representative shall take precedence over any action taken by the alternate authorized account representative if, in the Administrator's judgment, the actions are concurrent and conflicting;

(2) The alternate authorized account representative may be changed at any time by the authorized account representative upon submission of a new certificate of representation to the Administrator as provided in subsection (c).

(3) The alternate authorized account representative shall be subject to the provisions of this Part;

(4) Whenever the term "authorized account representative" is used in this Part it shall be construed to include the alternate authorized account representative, unless such a construction would be illogical from the context; and

(5) Any action, representation or failure to act by the alternate authorized account representative when acting in that capacity shall be deemed to be an action of the authorized account representative, with all the rights, duties, and responsibilities pertaining thereto.

(e) *Changes to the authorized account representative.* An authorized account representative for a non-unit account may be succeeded by any person who submits a New Account/New Authorized Account Representative Form and certification pursuant to paragraph (c) of this section. The actions of an authorized account representative for a non-unit account shall be binding on any successor.

(f) *Objections to the authorized account representative.* Except for a certification pursuant to paragraph (e) of this section, no objection or other communication submitted to the Administrator concerning any submission to the Administrator by the authorized account representative shall affect the recordation of transfers submitted by the authorized account representative pursuant to Subpart D. Neither the United States, the Administrator, nor any permitting authority will adjudicate any dispute between and among persons concerning any submission to the Administrator by the authorized account representative; any actions of the authorized account representative; or any other matter arising directly or indirectly from the certification, actions or representations of the authorized account representative.

§73.34 Recordation in Accounts

(a) *Recordation in compliance subaccounts.* At the beginning of 1995 and, in the case of each year thereafter, after the Administrator has made all deductions from a unit compliance subaccount pursuant to §73.35(b), the Administrator will record in the compliance subaccount established for each unit pursuant to §73.31(a) and §73.31(b) the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(b) *Recordation in future year subaccounts.* Allowances in each future year subaccount for each existing affected unit will reflect:

(1) All allowances allocated for the unit for the year pursuant to Subpart B;

(2) All allowances allocated pursuant to §72.41;

(3) All allowances allocated pursuant to §72.42;

(4) All allowances allocated pursuant to §72.43;

(5) All allowances allocated pursuant to §72.44;

(6) All allowances allocated pursuant to Subpart F;

(7) In the case of a unit or process source subject to the provisions of Part 74, all allowances allocated pursuant to Part 74;

(8) All allowances added as a result of purchases from the annual auctions or

direct sale pursuant to Subpart E;

(9) All allowances added or deducted as a result of allowance transfers recorded pursuant to Subpart D; and

(10) All allowances deducted pursuant to §73.35(e) and Part 77.

(c) *Recordation in current year subaccounts.* At the beginning of 1995 and each year thereafter, the Administrator will record in the current year subaccount established for non-units pursuant to §73.31(c) the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(d) *Serial numbers for allocated allowances.* Upon the allocation of allowances for an existing affected unit pursuant to Subpart B and the allocation of allowances pursuant to §72.41, §72.42, §72.43, and §72.44 and Part 74, the Administrator will assign each allowance a unique identification number.

(e) *Serial numbers for allowances in Reserves.* The Administrator will assign a unique identification number to each allowance transferred to an account from a reserve established pursuant to the requirements of §404(a)(2), §404(g), and §416(b) of the Act and Subpart B.

§73.35 Compliance

(a) *Allowance transfer deadline.*

(i) No allowance shall be used for purposes of compliance with a unit's sulfur dioxide emissions limitation requirements pursuant to Title IV of the Act and paragraph (b) of this section unless:

(A) The compliance use date of the allowance is no later than the year in which the unit's SO_2 emissions occurred; and

(B) By no later than the allowance transfer deadline, such allowance is recorded in the compliance subaccount or its transfer into the compliance subaccount is properly submitted for recordation in the compliance subaccount for the unit in accordance with the requirements of Subpart D.

(ii) The date of submission shall be the time of receipt as indicated by a time and date mark in the case of certified mail or by electronic transmission capable of indicating the time of receipt by the Administrator, in the case of a submission by electronic method.

(b) *Deductions for compliance.*

(1) Except as provided in paragraph (e) of this section, following the recordation of transfers properly submitted for recordation in the compliance subaccount pursuant to paragraph (a) of this section and Subpart D, the Administrator will deduct from each affected unit's compliance subaccount allowances equal in amount to the sum of:

(i) The unit's sulfur dioxide emissions tonnage during the immediately preceding calendar year as reported pursuant to Part 75; and

(ii) In the case of a unit subject to the requirements of §72.43, the sulfur dioxide emissions tonnage during the immediately preceding calendar year resulting from any compensating generation, pursuant to §72.43 and Subpart K of Part 72.

(2) The Administrator will make deductions until either the number of allowances deducted is equal in amount to the sum of the unit's sulfur dioxide emissions tonnage during the immediately preceding calendar year, calculated pursuant to (i) and (ii) of this paragraph, or until no more allowances remain in the subaccount. Following such deduction, the account will state the unit's excess emissions, if any.

(c) *Identification of allowances by serial number.* By no later than the allowance transfer deadline for the compliance subaccount, the authorized account representative for each unit account may identify by serial number the allowances to be deducted from the compliance subaccount for purposes of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made by submission of the Compliance Deduction Form, in Appendix A of this Part, or by such electronic method as the Administrator may prescribe in the future.

(d) *First-in, first-out.* In the absence of an identification of allowances by serial number, as provided for in paragraph (c) of this section, the Administrator will deduct allowances on a first-in, first-out (FIFO) accounting basis beginning with those allowances with the earliest compliance use date originally allocated for the unit and recorded in its compliance subaccount, and followed by those allowances allocated for other units and recorded in the unit's compliance subaccount account pursuant to Subpart D, beginning with those with the earliest date of recordation.

(e) *Deductions for excess emissions.* Unless otherwise provided in an approved excess emissions offset plan pursuant to Part 77, and following the process of recordation set forth in §73.34(a), the Administrator, pursuant to Part 77, will deduct from the compliance subaccount, for each unit with excess emissions for the preceding calendar year, allowances in an amount equal to the unit's excess emissions tonnage. The authorized account representative may identify by serial number in the excess emissions offset plan submitted pursuant to Part 77 the allowances to be deducted from the compliance subaccount. In the absence of such specification, the method for identifying allowances to be deducted pursuant to this section will be determined at the discretion of the Administrator.

(f) *Units subject to common emission stack plans.* In the case of units subject to a common stack plan pursuant to §75.11(a) and §72.50, the Administrator will aggregate the allowances recorded in the compliance subaccounts for all the units governed by the plan for purposes of making deductions pursuant to paragraphs (b) and (e) of this section. The Administrator will record in each unit's compliance subaccount each unit's per capita share, adjusted to the nearest allowance, of any aggregated allowances remaining following deductions made pursuant to paragraphs (b) and (e) of this section.

(g) *Units subject to amended Phase I substitution and compensating unit plans.* Following an administrative amendment to a compliance plan pursuant to §72.303(a)(11) with respect to unit(s) subject to a Phase I Substitution Plan or Phase I Compensating Unit Plan, the Administrator will deduct from the accounts of such unit(s) allowances recorded pursuant to §72.41(c)(2) in the case of a substitution plan or §72.43(b)(2) in the case of a compensating unit plan.

§73.36 Banking

(a) *Unit accounts.* Any allowance not deducted pursuant to §73.35 will remain in the compliance subaccount.

(b) *Non-unit accounts.* In the case of a non-unit account, any allowances in the current year subaccount at the end of the current calendar year will remain in the current year subaccount until transferred to another account pursuant to §73.52 and §73.53.

§73.37 Account Error and Dispute Resolution

(a) *Claim of error.* The authorized account representative may notify the Administrator of any claim that there is an error in an Allowance Tracking System account, provided that such notification is received by the Administrator by no later than either 20 business days following the submission of the transfer that is the subject of the notification or 10 business days following notification pursuant to §73.54 or §73.55, and that where such claim involves allowances transferred to or from a compliance subaccount, such notification shall be received by the Administrator by no later than 15 business days following the allowance transfer deadline. Such notification shall be in writing and shall include:

(1) A description of the alleged error;

(2) A proposed correction of the alleged error;

(3) Any supporting documentation or other information concerning the alleged error and proposed correction; and

(4) Certification by the authorized account representative.

The Administrator will not act on notifications received after the stated deadlines.

(b) *EPA action.* The Administrator, at the Administrator's sole discretion, will determine what changes, if any, will be made to the accounts subject to the alleged error. Not later than 30 days after receipt of notification pursuant to paragraph (a) of this section, the Administrator will submit to the authorized account representative a written response stating:

(1) The determination made and any action taken by the Administrator; and

(2) The reasons for such action.

(c) *Appeal for reconsideration.* The authorized account representative may appeal for reconsideration of the Administrator's denial, in whole or in part, of any claim that there is an error in an Allowance Tracking System account, by resubmitting the claim and the request, provided that the request for appeal is received by the Administrator by no later than 15 business days following the authorized account representative's receipt of notification of the Administrator's decision on the submitted error claim, and that where such claim involves allowances transferred to or from a compliance subaccount, such appeal shall be received by the Administrator by no later than 15 business days following the allowance transfer deadline. An authorized account representative may make only one appeal for reconsideration of a determination on a claim of error.

(d) *EPA corrections.* The Administrator may, without prior notice and at the Administrator's sole discretion, correct any errors in any account. The Administrator will notify the authorized account representative by no later than 30 days following such

corrections.

(e) *Excess Emissions Requirements.* The filing of notification pursuant to paragraph (a) of this section or the pendency of the Administrator's action pursuant to paragraph (b) of this section shall not affect a unit's obligations under Part 77.

(f) *Waiver of Deadline.* The Administrator may, in his or her discretion, accept submissions made following the deadlines imposed in this section upon a demonstration by the authorized account representative of good cause for the delay. The finding of whether good cause exists shall be in the sole discretion of the Administrator.

§73.38 Public Availability

Any person may review information compiled pursuant to §73.34 in the Allowance Tracking System. In the future, the Administrator will prescribe, following public notice, a method of electronic communication for reviewing such information.

§73.39 Closing of Accounts

(a) *Non-unit Accounts.* The authorized account representative of a non-unit account may instruct the Administrator to close the non-unit account by submitting a valid Allowance Transfer Form, in Appendix A of this Part, pursuant to §73.52 and §73.53, requesting the transfer of all allowances held in the account into another account in the Allowance Tracking System, and submitting in writing, with the signature of the authorized account representative, a request to delete the non-unit account from the Allowance Tracking System.

(b) *Inactive accounts.* If a non-unit account shows no activity for a period of a year or more and does not contain any allowances in its subaccounts, the Administrator will notify the account's authorized account representative that the account will be closed and eliminated from the Allowance Tracking System following 20 business days from the date the notice is sent. The account will be closed following the 20-day period, unless the Administrator receives and approves a request for recordation of the transfer of allowances into the account pursuant to §73.52, or the authorized account representative submits, in writing, demonstration of good cause as to why the inactive account should not be closed. The finding of good cause is at the sole discretion of the Administrator.

Subpart D

Subpart D is amended by removing it as previously published May 23, 1991 in 40 CFR Part 73, pages 23754-23759, and renaming it as Subpart E. A new Subpart D now reads as follows:

Subpart D -- Allowance Transfers

§73.50 Scope of Transfers

(a) Except as provided in §73.51, the Administrator will record transfers of an allowance to and from Allowance Tracking System accounts, including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year in perpetuity, provided that:

(1) Such transfers are authorized and certified in writing by the submission of a completed Allowance Transfer Form, or by such other method as the Administrator, through public notice, may prescribe in the future, by the authorized account representatives for both the transferror account and the transferee account;

(2) Each allowance identified by serial number specified pursuant to §73.52(a)(2) is in the transferror account, except when a request for transfer of the unit's allowances in perpetuity is indicated correctly on the Allowance Transfer Form;

(3) Allowances identified by serial number specified pursuant to §73.52(a)(2) are not subject to the limitations imposed pursuant to §72.44(f)(3)(i), and on opt-in sources reducing utilization pursuant to Part 74;

(4) (i) In the case of a transferror unit account for which a transfer is submitted for recordation in a compliance subaccount and:

(A) The unit had excess sulfur dioxide emissions in the immediately preceding calendar year, and

(B) The Administrator has not approved the unit's excess emissions offset plan or deducted allowances pursuant thereto from the unit's account,

(ii) No transfer will be recorded unless the total number of allowances in the compliance subaccount exceeds the sum of:

(A) The number of allowances subject to the transfer, and

(B) The unit's excess emissions in the immediately preceding calendar year; and

(5) Transfers of allowances in compliance subaccounts submitted for recordation following the allowance transfer deadline will not be recorded until after completion of the process of recordation set forth in §73.34(a).

(b) Notwithstanding any action by the Administrator following the submission of a transfer for recordation, it shall be unlawful within the meaning of §414 of the Act for any person to submit to the Administrator a transfer for recordation that fails to meet the requirements of paragraph (a) of this section.

§73.51 Prohibition

Except as provided in §73.34(a), the Administrator will not record a transfer of allowances from a future year subaccount to a subaccount for an earlier year.

§73.52 Submission of Transfers

(a) Authorized account representatives seeking recordation of a transfer of allowances shall submit to the Administrator an Allowance Transfer Form which shall, at a minimum, include:

(1) The numbers identifying both the transferror and transferee accounts;

(2) A specification by serial number of each allowance to be transferred;

(3) Signatures of the authorized account representatives of both the transferror and transferee account;

(4) Where the transferee account has not been established, information as required pursuant to §73.31 (b) or (c); and

(5) Where the transfer involves a unit account, certification of acknowledgement by the authorized account representative that no action the Administrator may take with respect to the requested transfer affects the unit's obligation to comply with its annual sulfur dioxide emissions limitation requirements.

(b) Following public notice, the Administrator may prescribe in the future alternative methods for submission of an allowance transfer for recordation.

§73.53 EPA Recordation

Except as provided in §73.50 and §73.51, the Administrator will record an allowance transfer by no later than five business days following receipt of information pursuant to §73.52, by deducting each allowance from the transferror account and adding it to the transferee account as specified pursuant to §73.52, provided that:

(a) The information submitted pursuant to §73.52 is complete;

(b) The transferror account includes each allowance identified by serial number in the information submitted pursuant to §73.52; and

(c) The transfer meets all applicable requirements of this Subpart.

§73.54 Notification

The Administrator will give notice of an allowance transfer within five business days following the recordation of the transfer. Notice will be in writing or by such other method as the Administrator may prescribe in the future following public notice, to the authorized account representatives of both the transferror and transferee accounts.

§73.55 Non-Recordation of Transfers

(a) *Notification of non-recordation.*

(1) Where an allowance transfer submitted for recordation fails to meet the requirements of this Subpart, the Administrator will not record such transfer. By no later than five business days following receipt of the Allowance Transfer Form by the Administrator, the Administrator will notify, in writing or by such electronic method as the Administrator will prescribe in the future through public notice, the authorized account representatives of the accounts subject to the allowance transfer submitted for recordation of:

(i) Such non-recordation, and

(ii) The reasons for such non-recordation.

(2) Nothing in this section shall preclude the submission of a transfer for

recordation following such notification.

(b) *Administrator's discretion not to record.* Notwithstanding any other provision of this Subpart, the Administrator, at the Administrator's sole discretion, may determine not to record a transfer where the transferror account is for a unit with excess emissions in the calendar year preceding the date on which the transfer is submitted or is subject to a proposed or approved compliance plan pursuant to the requirements of Part 77.

Subpart E -- Auctions, Direct Sales, and Independent Power Producers Written Guarantee

Subpart E was previously published May 23, 1991 in 40 CFR Part 73, pages 23754-23759, as Subpart D, and is now renamed as Subpart E.

Subpart F -- Energy Conservation and Renewable Energy Reserve

§73.80 Operation of Allowance Reserve Program for Conservation and Renewable Energy

(a) *General.* Upon approval of applications submitted by one or more electric utilities, for each ton of sulfur dioxide emissions deemed to have been avoided during the period of applicability through the use of one or more qualified energy conservation measures or of qualified renewable energy generation during a previous calendar year or years, the Administrator will allocate a single allowance from the Conservation and Renewable Energy Reserve (the "Reserve") in the order in which applications are received until a total of 300,000 allowances have been allocated.

(b) *Period of applicability.* Allowances will be allocated under this Subpart for energy conservation measures or renewable energy generation sources that are operational after January 1, 1992, and before the earlier of December 31, 2000 or the date on which any unit owned or operated by the applicant becomes an affected unit under Title IV.

(c) *Termination of the Reserve.* The Administrator will allocate any allowances remaining in the Reserve after January 2, 2010 to affected units under §405 of the Act from whom allowances were withheld for purposes of establishing the Reserve. Each unit's allocation will be calculated as follows:

$$\frac{\text{Remaining allowances in the Reserve} \times \text{Unit's allowances withheld}}{\text{Total amount in Reserve}}$$

(Allowances will be rounded to the nearest allowance)

§73.81 Qualifying Conservation Measures and Renewable Energy Generation

(a) *Qualified energy conservation measures.* A qualified energy conservation

measure is a material or device not operational until the period of applicability, installed in the residence or facility of a customer to whom the electric utility sells electricity, that:

(1) Is specified in Appendix B(1); or

(2) In the case of a device or material that is not included in Appendix B(1), is a cost-effective demand-side measure consistent with an applicable least-cost plan that increases the efficiency of the customer's use of electricity (as measured in accordance with applicable State verification procedures or protocol or with the EPA Conservation Verification Protocol) without increasing the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or industrial waste gases; and

(i) Is approved by the State regulatory authority that regulates the rates of the applicant; or

(ii) Is approved by the Administrator, when the applicant is an electric utility whose rates are not regulated by a State regulatory authority.

(b) *Non-qualifying energy conservation measures.* Qualified energy conservation measures shall not include:

(1) Measures that were operational before January 1, 1992;

(2) Supply-side measures;

(3) Conservation programs that are exclusively informational or educational in nature; or

(4) Load management, unless kilowatt hour savings can be verified by the electric utility pursuant to §73.82(c).

(c) *Qualified renewable energy generation.* Qualified renewable energy generation is electric generation, not operational until the period of applicability, that:

(1) Is specified in Appendix B(3); or

(2) In the case of renewable energy generation that is not included in Appendix B(3), is energy generation derived from biomass (i.e., combustible energy-producing materials from biological sources which include wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources and

(i) Is approved by the State regulatory authority that regulates the rates of the applicant; or

(ii) Is approved by the Administrator, when the applicant is an electric utility whose rates are not regulated by a State regulatory authority.

(d) *Non-qualifying renewable energy generation.* Qualified renewable energy generation shall not include:

(1) Renewable energy generation that was operational before January 1, 1992;

(2) Measures that do not generate electricity directly, including but not limited to measures that may reduce electricity demand without providing electric generation directly to the electric utility for sale to customers; and

(3) Measures that appear on the list of qualified energy conservation measures in Appendix B(1).

§73.82 Application for Allowances from Reserve Program

(a) *Application Requirements.* Each application for Conservation and Renewable Energy Reserve allowances, as included in Appendix A of this Part, and accompanying documentation, shall demonstrate that:

(1) The applicant, or any subsidiary of the applicant, owns or operates, in whole or in part, at least one affected unit or is a utility or industrial customer which purchases power from an affected unit (or units) under "life-of-the-unit" firm power contractual arrangements as defined in §402(27) of the Act (the applicant shall list the name and Allowance Tracking System account number of an affected unit which it owns or operates);

(2) The applicant is paying in whole or in part for qualified conservation measures or qualified renewable energy generation (implemented during the period of applicability) either directly or through payment to another person that purchases the qualified conservation measure or qualified renewable energy generation (the applicant shall specify the amount spent on the conservation measure or the renewable energy generation);

(3) The qualified energy conservation measure adopted or qualified renewable energy generated, or both, do not result in any net increase in sulfur dioxide emissions (the applicant shall certify that this requirement was met);

(4) The applicant has prepared, pursuant to a least-cost planning process that provides an opportunity for public notice and comment, and the applicant is implementing to the maximum extent practicable, a least cost plan that treats demand-side resources and supply-side resources on a consistent and integrated basis; takes into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk; and that may take into account other factors, including the social and environmental costs and benefits of resource investments;

(5) The qualified energy conservation measure adopted or qualified renewable energy generated, or both, are consistent with the least cost plan;

(6) If the applicant is subject to the rate-making jurisdiction of a State regulatory authority, its least cost plan has been approved and such approval has been certified by the regulatory authority in the State in which the qualifying conservation measures are adopted or in which the renewable energy generation is utilized;

(7) If the applicant is not subject to the rate-making jurisdiction of a State regulatory authority, its least cost plan has been approved and certified by the entity with rate-making authority for such utility for the State in which the qualifying conservation measures are adopted or in which the renewable energy generation is utilized;

(8) If the applicant is not subject to the jurisdiction of an entity with ratemaking authority, the applicant has enclosed a copy of its least cost plan with its application for approval by the Administrator;

(9) (i) If the applicant is subject to the ratemaking jurisdiction of a State regulatory authority and is submitting an application on the basis of qualified energy conservation measures, such State regulatory authority has established rates and charges ensuring that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the electric utility's conservation programs, which rates and charges may include:

(A) General rate-making formulas that decouple utility profits from actual utility sales;

(B) Specific rate adjustment formulas that allow a utility to recover in its retail rates the full costs of conservation measures plus any associated net revenues lost as a result of reduced sales resulting from conservation initiatives; and

(C) Conservation incentive mechanisms designed to provide positive financial rewards to a utility to encourage implementation of cost-effective measures; and

(ii) Pursuant to paragraph (b) of this section, the Secretary of Energy has certified the establishment of such net income neutrality;

(10) The applicant has implemented qualified energy conservation measures identified in the application and/or used qualified renewable energy generation specified in the application for purposes of avoiding emissions during the period of applicability;

(11) The installation of qualified conservation measures has achieved actual energy savings, by stating, on the basis of their performance following installation:

(i) The amount of energy savings (in kilowatt hours) resulting from the measures per year;

(ii) Pursuant to paragraph (c) of this section, the methodology used to calculate the savings; and

(iii) The name of the person who performed the calculation;

(12) The amount of yearly qualified renewable energy generation has achieved actual energy savings, by stating (and submitting documentation, including copies of plant operation records, supporting such statements):

(i) The hours of operation (on a BTU basis) during a previous calendar year or years; and

(ii) The nameplate capacity, in megawatts, of the renewable generation facility;

(13) Qualified renewable energy generation using a hybrid generating facility, including, but not limited to, a municipal solid waste combustion facility, has achieved actual energy savings, by stating (and submitting documentation, including copies of plant operation records, supporting such statements):

(i) The quantity of renewable energy input (on a Btu basis) and the portion of electric generation that can be attributed to that renewable energy input; and

(ii) The nameplate capacity, in megawatts, of the hybrid renewable generation facility;

(14) The implementation of qualified energy conservation measures or the use of qualified renewable energy generation has resulted in avoided sulfur dioxide emissions during the period of applicability, by stating the number of tons avoided as calculated pursuant to paragraph (d) of this section.

(b) *Application to the Secretary of Energy.*

(i) Using Supplement A of the Application for Energy Conservation and Renewable Energy Reserve Allowances, for purposes of this paragraph and paragraph (a)(9)(ii) of this section, the applicant shall submit to the Secretary of Energy:

(A) A copy of the relevant State regulatory authority's final order or decision setting forth the approved rate-making mechanisms that ensure that an electric utility's net income will be at least as high upon implementation of conservation measures as

such net income would have been if the energy conservation measures had not been implemented;

(B) A description of how the order or decision meets the definition of net income neutrality as defined in these regulations; and

(C) Any additional information necessary for the Secretary of Energy to certify that the State regulatory authority has established rates and charges that ensure net income neutrality.

(ii) If an electric utility applying for allowances from the Reserve has already received certification of net income neutrality from the Secretary of Energy in connection with a previous application for allowances, and the rate-making methods or procedures that ensure net income neutrality have not been altered, the applicant shall indicate in Supplement A of the application form that the rate-making methods and procedures that led to the original certification are still in place.

(c) *Verification of qualified conservation measures.* For the purposes of paragraph (a)(11) of this section:

(i) Applicants subject to the ratemaking jurisdiction of a State regulatory authority shall use the verification methodology approved by such authority;

(ii) Applicants whose rates are not subject to the ratemaking jurisdiction of a State regulatory authority shall use the EPA Conservation Verification Protocol, copies of which will be available from the Administrator at the address listed in paragraph (e) of this section.

(iii) The Administrator reserves the right to conduct independent audits to ascertain that the verification is valid and correct.

(d) *Calculation of allowances to be allocated.* For purposes of paragraph (a)(10) of this section:

(i) In the case of an application submitted on the basis of qualified energy conservation measures, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A) \times (B)}{2000 \text{ lbs.}}$$

(Rounded to the nearest ton)

Where:
(A) = the kilowatt hours that were not, but would otherwise have been, supplied by the utility during such year in the absence of such qualified energy conservation measures.
(B) = 0.004 lbs. per kilowatt hour.

(ii) In the case of an application submitted on the basis of qualified renewable energy generation, the emission tonnage deemed avoided for any calendar year shall be equal to the product of:

$$(A) \times (B)$$

2000 lbs.

(Rounded to the nearest ton)

Where:
(A) = the actual kilowatt hours generated by, or purchased from, qualified renewable energy based on the renewable energy input at a facility.
(B) = 0.004 lbs. per kilowatt hour.

(e) *Certification by Certifying Official.* Certification of all application requirements, including Supplement A, shall be made by a certifying official of the applicant upon such official's verification of all information and documentation submitted.

(f) *Certification of the accuracy of the application and compliance with the Act and the regulations.* Applicants subject to the ratemaking jurisdiction of a State regulatory authority shall include a certification by such authority that it has reviewed the application and Supplement A, including supporting documentation, and finds them to be accurate and complete.

(g) *Time period to apply.* Beginning no earlier than January 1, 1993, applicants may apply simultaneously or separately to:

(1) The Administrator for allowances from the Reserve for emissions avoided in a previous year or years by use of qualified conservation measures or qualified renewable energy generation that were operational beginning in the period of applicability; and

(2) The Secretary of Energy for the Secretary's certification of net income neutrality where the application is based on the use of qualified conservation measures. Applications will be received by the Administrator and the Secretary of Energy until January 2, 2010, pursuant to §73.80(c).

(h) *Submittal location.* Completed applications, not including Supplement A, shall be submitted to:
U.S. Environmental Protection Agency
Acid Rain Division (ANR-445)
401 M Street, S.W.
Washington, D.C. 20460
Attn. Conservation and Renewable Energy Reserve

Supplement A shall be submitted to:
U.S. Department of Energy
Office of the Secretary
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Attn. Net Income Neutrality Certification

§73.83 Secretary of Energy's Action on Supplement A of the Application

(a) *First come, first served.* The Secretary of Energy will process and certify applications according to the order, by date and time, in which they are received from either the applicant or the Administrator, in the case of an application submitted to the Administrator and then forwarded to the Secretary. If an application that includes Supplement A is submitted to the Administrator, Supplement A will be forwarded by the Administrator to the Department of Energy (DOE) within 5 business days of receipt.

(b) *Deficient applications.* If the Secretary of Energy determines that Supplement A is deficient, the Secretary will notify the applicant and the Administrator in writing of the deficiency. The applicant may then supply additional information or a new revised application as necessary for the Secretary to make a determination that the applicant meets the requirements of §73.82(a)(9). Additional information or revised applications will be processed according to the date and time of receipt of such information or revisions.

(c) *Notification of approval.* The Secretary of Energy will review the application to determine whether it meets the requirements of §73.82(a)(9)(i) and will certify this finding in writing to the applicant and to the Administrator within 60 calendar days of receipt of Supplement A or a revised application.

§73.84 Administrator's Action on Applications

(a) *First come, first served.* The Administrator will process and approve applications in whole or in part in order of date and time of receipt, provided that the Administrator shall not allocate more than a total of 30,000 allowances in connection with applications based on any one of the four categories of qualified renewable energy generation enumerated in §73.81(c)(2) and Appendix B(3.1 - 3.4).

(b) *Deficient applications.* The Administrator will return applications that fail to meet the requirements set forth in §73.82. Revised applications will be processed according to the date and time of receipt of such revised applications.

(c) *Notification of approval.* Complete and correct applications will be conditionally approved (pending certification from the Department of Energy) within 90 calendar days of receipt. Allowances from the Reserve will be designated for such applications depending on the availability of allowances in the Reserve. Final approval will be granted upon notification of certification by the Secretary of Energy pursuant to §73.83. The Administrator will notify applicants of final approval in writing.

(d) *Transfer of allowances.* Upon final approval, the Administrator will transfer allowances from the Reserve for each approved application into a single designated account in the Allowance Tracking System. If the applicant does not have an account in the Allowance Tracking System, or wishes to open a new account for the allowances from the Reserve, a completed New Account/New Authorized Account Representative Form must accompany the Application for Conservation and Renewable Energy Reserve.

(e) *Partial fulfillment of requests.*

(1) In the event that the allowances available in the Reserve are less than the number that would otherwise be issued to an approved applicant, the applicant will

receive the number of allowances remaining in the Reserve.

(2) In the event that a subaccount is established, pursuant to §73.85(a), and the applicant is making a request for allowances not included in the subaccount, the allocation for the approved applicant will be made from any allowances remaining in the Reserve.

(f) *Oversubscription of the Reserve.*

(1) If applications are received by the Administrator after all allowances from the Reserve have been allocated, the Administrator will so notify the applicant within 5 business days after receipt of the application.

(2) In the event that applications meeting the requirements pursuant to §73.82 are received by the Administrator prior to February 1, 1998, and

(i) All remaining allowances in the Reserve have been placed in a subaccount pursuant to §73.85(b); and

(ii) The applicant is not eligible for an allocation of allowances from the subaccount, the application will be placed on a waiting list in order of receipt.

(3) The Administrator will notify the certifying official of such action within 5 business days after receipt of the application. If any allowances are returned to the Reserve after February 1, 1998 pursuant to §73.85(c), the Administrator will review the wait-listed applications in order of receipt and allocate any remaining allowances to the approved applicants until no more allowances remain in the Reserve.

§73.85 Administrator Review of the Reserve Program

(a) *Administrator review of the Reserve and creation of a subaccount.* In the event that an allocation of allowances from the Reserve pursuant to a pending application would bring the total number of allowances allocated to a number greater than 240,000, the Administrator will review the distribution of all allowances allocated.

(1) If at least 60,000 allowances have been awarded for <u>each</u> of:

(i) Qualified energy conservation measures; and

(ii) Qualified renewable energy generation, distribution of allowances will continue pursuant to §73.82, until no more allowances remain in the Reserve.

(2) If fewer than 60,000 allowances have been allocated for either qualified energy conservation measures or qualified renewable energy generation, the Administrator will establish a subaccount for the allocation of allowances for applications based on the category for which fewer than 60,000 allowances have been allocated. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

(b) *Allocation of allowances from the subaccount.* The Administrator will allocate allowances from the subaccount to qualified applicants on a first come, first served basis, pursuant to §73.84(a), until the subaccount is depleted or closed pursuant to paragraph (c) of this section.

(c) *Closure of the subaccount.* Unless all allowances in the subaccount are allocated earlier, the Administrator will terminate the subaccount not later than February 1, 1998 and return any allowances remaining in the subaccount to the Reserve.

After applications subject to §73.84(f)(2) are approved, the Administrator will allocate any remaining allowances to any eligible applicant under this Subpart on a first-come, first-served basis.

§73.86 State Regulatory Autonomy

Nothing in this Subpart shall preclude a state or state regulatory authority from providing additional incentives to utilities to encourage investment in any conservation measures or renewable energy generation.

APPENDIX A TO PART 73 - Allowance System Forms

INSTRUCTIONS FOR COMPLETING THE ALLOWANCE TRACKING SYSTEM NEW ACCOUNT/ NEW AUTHORIZED ACCOUNT REPRESENTATIVE FORM

GENERAL INFORMATION

This form must be submitted to establish a new non-unit account in EPA's allowance tracking system. Completed applications should be returned to:

U.S.E.P.A.
Acid Rain Division (ANR-445)
401 M Street, S.W.
Washington, D.C., 20460
Attn: Allowance Tracking System Accounts

PAPERWORK REDUCTION ACT
The public reporting burden for this collection of information is estimated to average 30 hours per response including time for reviewing instructions, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding this burden estimate or any other aspects of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S. E.P.A. 401 M Street, SW. Washington, D.C. 20460 Attn.: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, D.C. 20603.

NOTE: Please type or print legibly in ink.

A. AUTHORIZED ACCOUNT REPRESENTATIVE INFORMATION

AUTHORIZED ACCOUNT REPRESENTATIVE
Enter the name of the officially authorized account representative (a natural person who may trade, transfer, and otherwise dispose of allowances held in an account in the allowance tracking system, including, but not limited to, the designated representative of owners and operators of an affected unit).

ADDRESS
Provide the complete address, including zip code, of the authorized account representative. All mailings will be sent to this address.

TELEPHONE NUMBER
Indicate the authorized account representative's daytime area code and phone number.

TELEFACSIMILE NUMBER
Enter the authorized account representative's telefacsimile number, if applicable.

ALLOWANCE TRACKING SYSTEM NUMBER
If using this form to change the authorized account representative for an established allowance tracking system account provide the account number.

TYPE OF ORGANIZATION
Indicate the primary business of the individual, company, or organization that the authorized account representative represents.

B. OWNERSHIP INTEREST IN ALLOWANCES

NAMES AND ADDRESSES OF OWNERS
Indicate the names and addresses of all persons with an ownership interest with respect to allowances held in the non-unit account. If the authorized account representative is the only person with an ownership interest in the allowances go to section C.

C. AGREEMENT OF REPRESENTATION

This section lists the requisite elements for a binding agreement between the authorized account representative and persons with ownership interest in the allowances. EPA will not review the agreement, nor will it become a party to any disputes regarding the agreement.

D. CERTIFICATION

Sign and date the form. The signature provided should be that of the authorized account representative identified in section A.

Form Approved. OMB Number 2060-xxxx. Approval Expires xxxxx

United States Environmental Protection Agency

Washington, DC 20460

Allowance Tracking System New Account/ New Authorized Account Representative Form

A. Account Information

Name and Address of New Authorized Account Representative	Telephone Number
	Telefascimile Number
	Allowance Tracking System Number *

Type of Organization *(Please check all that apply)*

_____**Utility Generator of Electricity**
- _____Regulated, investor owned electric utility
- _____Regulated, policy owned electric utility
- _____Non-regulated, investor owned electric utility

_____**Non-utility Generator of Electricity**
- _____Qualifying cogenerator as defined by the Public Regulatory Policy Act of 1978 (PURPA)
- _____Other Independent Power Producer (IPP)
- _____Self generator of electricity

_____**Owner or operator of an industrial facility producing steam**

_____**Owner or operator of a process source as defined by the Clean Air Act Amendments of 1990**

_____**Fuel Company**
- _____ Coal
- _____ Other *(please explain)*_____
- _____ Integrated *(produce and sell)*

_____**Fuel Broker**
- _____Coal
- _____Other *(please explain)*_____

_____**Railroad transporter of coal**

_____**Pollution control company**

_____**Public interest group**
- _____Consumer
- _____Environmental

_____**Broker/marketer of allowances**

_____**Other** *(please explain)*_____

B. Ownership Interest In Allowances

Name and Address of Interested Person

EPA Form 7600-2 (6-91) * *Complete only if using this form to change the authorized account representative for this account* number.

827546

Name and Address of Interested Person

Name and Address of Interested Person

Name and Address of Interested Person

Name and Address of Interested Person

C. Agreement of Representation

The authorized account representative for the allowance tracking system account was selected under the terms of an agreement that is binding on all persons who have an ownership interest with respect to the allowances held in the allowance tracking system account.

The authorized account representative has all necessary authority to carry out the duties and responsibilities that are assigned to the authorized account representative under 40 CFC Part 73.

The authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the binding agreement..

D. Certification

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

Name of Authorized Account Representative (Please Print)

Signature

Date

FOR EPA USE ONLY	**Control #**
	Time/Date

INSTRUCTIONS FOR COMPLETING THE SO2 ALLOWANCE DEDUCTION FORM

GENERAL INFORMATION

NOTE: Please type or print in ink.

EPA established an Allowance Tracking System to record the allocation, transfer, deduction of sulfur dioxide allowances. An Allowance Tracking System account was established for each existing unit that is, or shall become an affected unit, and will be established for other allowance holders who submit the New Account/New Authorized Account Representative Form. Each Allowance Tracking System account is identified by a unique account number. Each account consists of two types of subaccounts: one containing allowances that may be used for compliance with a unit's emissions limitation requirements in the current calendar year; and the other type containing allowances that may be used for compliance in specified future calendar years. There will be 30 of the latter type covering the 30 years after the current year.

Each allowance will be assigned a unique identification number including; (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

No allowance may be used for compliance purposes unless it is properly recorded or an Allowance Transfer Form has been properly submitted for recordation in the unit's compliance subaccount on or before the "allowance transfer deadline", which is January 30 of the calendar year following the year in which the emissions took place.

Following the recordation of transfers properly submitted for recordation in the compliance subaccount, EPA will deduct from each affected unit's compliance subaccount, allowances equal to the sum of:

a) the unit's reported sulfur dioxide emissions tonnage during the preceding calendar year; and

b) sulfur dioxide emissions tonnage during the preceding year resulting from any compensating generation.

EPA will continue to deduct allowances until either the number of allowances deducted equals the sum of a) and b) above or until no more allowances remain in the subaccount.

By no later than the "allowance transfer deadline", the authorized account representative for the compliance subaccount may identify by serial number the allowances to be deducted from the compliance subaccount for the purposes of compliance with the unit's emissions limitation requirements.

Allowances used for compliance will be deducted from the affected unit's compliance subaccount following the "allowance transfer deadline".

Completed Allowance Deduction Forms should be mailed to the following address:

U.S.E.P.A.
Acid Rain Division (ANR-445)
401 M Street, S.W.
Washington, D.C., 20406
Attn: Allowance Tracking System

A copy of the Allowance Deduction Form should be maintained in case of account error or dispute. In case of error, the authorized account representative may notify EPA in writing at the above address.

For more information on the allocation, transfer and use of allowances, see 40 CFR 73.10-55.

PAPERWORK REDUCTION ACT
The public reporting burden for this collection of information is estimated to average 1 hour per response including time for reviewing instructions, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding this burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S. EPA 401 M Street, SW., Washington, DC 20460 Attn: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

A. SERIAL NUMBERS OF ALLOWANCES TO BE DEDUCTED

List the serial number(s) of the allowance(s) to be deducted. Each allowance serial number consists of; (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

1. YEAR
Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. START NUMBER
Provide the unique identification number of the allowance to be deducted (last 7 digits of the allowance serial number). If you are deducting allowances with consecutive numbers, provide the unique identification number of the first allowance in the series.

3. FINISH NUMBER
If you are deducting allowances with consecutive numbers, provide the unique identification number of the last allowance in the series (last 7 digits of the allowance serial number). If you are deducting a single allowance, enter N/A or the same number entered in Block 3.

B. ACCOUNT INFORMATION

1. ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Enter the Allowance Tracking System account number for the unit account you wish to deduct allowances from.

2. AUTHORIZED ACCOUNT REPRESENTATIVE
Indicate the name of the person designated as the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative) for the Allowance Tracking System account.

3. TELEPHONE NUMBER
Indicate the daytime area code and telephone number of the authorized account representative.

4. TELEFACSIMILE NUMBER
Indicate the daytime area code and telefacsimile number of the authorized account representative (if available).

5. SIGNATURE
The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. DATE
Indicate the date on which the form was signed by the authorized account representative.

You must complete a separate Attachment A for each non-consecutively numbered allowance or series of allowances you wish to deduct.

OMB No. 2060-XXXX
Expires

SO2 ALLOWANCE DEDUCTION FORM

A. SERIAL NUMBERS OF ALLOWANCES TO BE DEDUCTED

List the serial numbers of allowances to be deducted on line 1 below (if numbered consecutively).

Are there attachments that list additional allowance deductions? ___ Yes ___ No
(A separate Attachment A must be completed for each non-consecutively numbered allowance or series of allowances to be deducted).

Number of Attachments that follow: _____.

1. Year	2. Start Number	3. Finish Number
_____	_____	_____

B. ACCOUNT INFORMATION

1. Allowance Tracking System Account Number _____
2. Authorized Account Representative _____
3. Telephone Number _____
4. Telefacsimile Number (if available) _____

CERTIFICATION

I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this deduction to act with regard to such allowances. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature _____
6. Date _____

For Official Use Only

ATTACHMENT A
SO2 ALLOWANCE DEDUCTION FORM

NOTE: Please type or print in ink.

Attachment A is used to indicate the serial number(s) of the allowance(s) to be deducted. Each allowance serial number consists of three parts: (1) the unique identification of the allowance; (2) the calendar year in which the allowance may first be used for compliance purposes; and (3) the account in which the allowance is initially allocated.

You must complete a separate Attachment A for each non-consecutively numbered allowance or series of allowances you wish to deduct.

A. ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER

Enter the Allowance Tracking System account number for the unit account you wish to deduct allowances from.

B. SERIAL NUMBER(S) OF ALLOWANCE(S) TO BE DEDUCTED

1. YEAR
Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. ORIGINAL ACCOUNT IDENTIFICATION
Indicate the identification number of the account to which the allowance was originally allocated (the next 12 digits of the allowance serial number(s)).

3. START NUMBER
Provide the unique identification number of the allowance to be deducted (last 6 digits of the allowance serial number). If you are deducting allowances with consecutive numbers, provide the unique identification number of the **first** allowance in the series.

4. FINISH NUMBER
If you are deducting allowances with consecutive numbers, provide the unique identification number of the **last** allowance in the series (last 6 digits of the allowance serial number). If you are deducting a single allowance, enter N/A or the same number entered in Block 3.

A. ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER _____

B. SERIAL NUMBERS OF ALLOWANCES TO BE DEDUCTED

List the serial numbers of allowances to be deducted on line 1 below (if numbered consecutively).

A separate Attachment A must be completed for each non-consecutively numbered allowance or series of allowances to be deducted.

1. Year	3. Start Number	3. Finish Number
_____	_____	_____

INSTRUCTIONS FOR COMPLETING THE SO2 ALLOWANCE TRANSFER FORM

GENERAL INFORMATION

NOTE: **Please type or print in ink.**

EPA established an allowance tracking system to record the allocation and transfer of sulfur dioxide allowances. An Allowance Tracking System account was established for each existing unit that is, or shall become an affected unit, and will be established for other allowance holders who submit the New Account/New Authorized Account Representative Form. Each Allowance Tracking System account is identified by a unique account number. Each account consists of two types of subaccounts: one containing allowances that may be used for compliance with a unit's emissions limitation requirements in the current calendar year; and the other type containing allowances that may be used for compliance in specified future calendar years. There are 30 of the latter type covering the 30 years after the current year.

Each allowance is assigned a unique identification number including; (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

Transfers of sulfur dioxide allowances must be recorded in the Allowance Tracking System if the transfer is to be reflected in the transferror and transferee accounts. Unless an allowance is recorded in a unit's account, it cannot be used to offset the unit's emissions. Completed Allowance Transfer Forms should be mailed to the following address:

U.S.E.P.A.
Acid Rain Division (ANR-445)
401 M Street, S.W.
Washington, D.C., 20406
Attn: Allowance Tracking System

Upon receipt of an Allowance Transfer Form, EPA will deduct the allowances from the transferror account and add them to the transferee account provided that:

a) The Allowance Transfer Form is complete, and includes the certifying signatures of the authorized account representatives of both parties and the serial numbers of the allowances to be transferred;

b) The allowances are in the transferror account; and

c) The allowances have not been allocated for purposes of authorizing an extension of the transferror unit's compliance deadline in connection with the installation of repowering technology.

In addition, if the transferror unit has had excess emissions in the year preceding the transfer and EPA has not yet deducted allowances to offset the excess emissions, the number of allowances that can be transferred will be limited.

If an allowance transfer does not meet the requirements stated above, EPA will not record the transfer and will inform the affected authorized account representatives of the reasons that transfer was not recorded.

Upon recording an allowance transfer, EPA will notify the authorized account representatives of the transferror and transferee that the transfer has been recorded.

No allowance may be used for compliance purposes unless it is properly recorded, or a transfer has been properly submitted for recordation in, the unit's compliance subaccount before the "allowance transfer deadline", which is January 30 of the calendar year following the year in which the emissions took place.

Allowances used for compliance will be deducted from the affected unit's compliance subaccount following the "allowance transfer deadline".

A copy of the Allowance Transfer Form or other documentation verifying that a transfer has taken place should be maintained by one or both parties in case of account error or dispute. In case of error, the authorized account representative may notify EPA in writing at the above address.

For more information on the allocation, transfer and use of allowances, see 40 CFR 73.10-55.

PAPERWORK REDUCTION ACT
The public reporting burden for this collection of information is estimated to average 1 hour per response including time for reviewing instructions, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding this burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S. EPA 401 M Street, SW., Washington, DC 20460 Attn: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

A. SERIAL NUMBERS OF ALLOWANCES TO BE TRANSFERRED

Attachment A, indicating the serial numbers of allowances to be transferred, must be submitted with this form.

B. TRANSFERROR INFORMATION (SELLER)

1. ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Enter the transferror's Allowance Tracking System account number. The transferror must have a valid account number to transfer allowances in the Allowance Tracking System.

2. AUTHORIZED ACCOUNT REPRESENTATIVE
Indicate the name of the person designated as the transferror's authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

3. TELEPHONE NUMBER
Indicate the daytime area code and telephone number of the transferror.

4. TELEFACSIMILE NUMBER
Indicate the daytime area code and telefacsimile number of the transferror (if available).

5. SIGNATURE
The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. DATE
Indicate the date on which the form was signed by the authorized account representative.

C. TRANSFEREE INFORMATION (PURCHASER)

1. ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Enter the transferee's Allowance Tracking System account number. If an account has not been established for the transferee, a completed New Account/New Authorized Account Representative Form must accompany the Allowance Transfer Form. If a completed New Account/New Authorized Account Representative Form is provided, the transferee may omit question 1 in section C of the Allowance Transfer Form. However, the transferee must be sure to complete questions 2 through 6 on the Allowance Transfer Form. The New Account/New Authorized Account Representative Form may be obtained by contacting EPA at the address provided on page 1 of these instructions.

2. AUTHORIZED ACCOUNT REPRESENTATIVE
Indicate the name of the person designated as the transferee's authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

3. TELEPHONE NUMBER
Indicate the daytime area code and telephone number of the transferee.

4. TELEFACSIMILE NUMBER
Indicate the daytime area code and telefacsimile number of the transferee (if available).

5. SIGNATURE
The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. DATE
Indicate the date on which the form was signed by the account representative.

OMB No. 2060-XXXX
Expires

SO2 ALLOWANCE TRANSFER FORM

A. SERIAL NUMBER(S) OF ALLOWANCE(S) TO BE TRANSFERRED

Attachment A, indicating the serial numbers of allowances to be transferred, must be submitted with this form.

B. TRANSFERROR INFORMATION (SELLER)

1. Allowance Tracking System Account Number _____
2. Authorized Account Representative _____
3. Telephone Number _____
4. Telefacsimile Number (if available) _____

CERTIFICATION

I submit this form pursuant to EPA's regulations governing the transfer of allowances as set forth in 40 CFR 73. I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this transfer to act with regard to such allowances. I acknowledge and certify no action that EPA may take with respect to this transfer of allowances nullifies an affected unit's obligation to comply with its annual emissions limitation requirements. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature _____
6. Date _____

C. TRANSFEREE INFORMATION (PURCHASER)

If you do not have an Allowance Tracking System Account, you must leave item 1 of this section blank, and submit a completed New Account/New Authorized Account Representative Form with this document.

1. Allowance Tracking System Account Number _____
2. Authorized Account Representative _____
3. Telephone Number _____
4. Telefacsimile Number (if available) _____

CERTIFICATION

I submit this form pursuant to EPA's regulations governing the transfer of allowances as set forth in 40 CFR 73. I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this transfer to act with regard to such allowances. I acknowledge and certify no action that EPA may take with respect to this transfer of allowances nullifies an affected unit's obligation to comply with its annual emissions limitation requirements. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature _____
6. Date _____

For Official Use Only

ATTACHMENT A
SO2 ALLOWANCE TRANSFER FORM

NOTE: Please type or print in ink.

Attachment A is to be used to indicate the serial number(s) of the allowance(s) to be transferred. Each allowance serial number consists of; (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

A. SERIAL NUMBER(S) OF ALLOWANCE(S) TO BE TRANSFERRED

Check the box if you wish to transfer these allowances for every year in perpetuity, in which case no finish number is needed. If you check this box, EPA will transfer these allowances for every year unless another allowance transfer form is received with other instructions.

1. YEAR
Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. START NUMBER
Provide the unique identification number of the allowance to be transferred (last 7 digits of the allowance serial number). If you are transferring allowances with consecutive numbers, provide the unique identification number of the first allowance in the series.

3. FINISH NUMBER
If you are transferring allowances with consecutive numbers, provide the unique identification number of the last allowance in the series (last 7 digits of the allowance serial number). If you are transferring a single allowance, enter N/A or the same number entered in Block 3.

B. ACCOUNT INFORMATION

1. TRANSFERROR ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Enter the transferror's Allowance Tracking System account number.

2. TRANSFEREE ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Enter the transferee's Allowance Tracking System account number. If the transferee does not have an account number, leave item 2 blank, and attach an New Account/New Authorized Account Representative Form.

You must complete a separate Attachment A for each non-consecutively numbered allowance or series of allowances you wish to transfer.

A. SERIAL NUMBER(S) OF ALLOWANCE(S) TO BE TRANSFERRED

Number of Attachment A's: _____

Check here if you wish to transfer these allowances for every year in perpetuity. _____

1. Year	2. Start Number	3. Finish Number
_____	_____	_____

B. ACCOUNT INFORMATION

1. Transferror Allowance Tracking System Account Number _____
2. Transferee Allowance Tracking System Account Number _____

APPLICATION FOR ENERGY CONSERVATION AND RENEWABLE ENERGY RESERVE ALLOWANCES

(Not Including Supplement A)

PLEASE READ THE FOLLOWING SECTIONS CAREFULLY BEFORE COMPLETING THIS APPLICATION.

Who Qualifies for Allowances from the Energy Conservation and Renewable Energy Reserve

Section 404(g) of the Clean Air Act Amendments of 1990 (CAAA) requires EPA to establish a Conservation and Renewable Energy Reserve that sets aside 300,000 sulfur dioxide allowances for allocation to qualified utilities. Utilities applying for these allowances must meet the following requirements:

(A) Applicants must be electric utilities that own or operate, in whole or in part, an "affected unit," pursuant to the guidelines set forth under "life-of-the-unit," firm power contractual arrangements as defined in CAA section 402(27). "Affected unit" is defined in CAAA section 402(2) as a unit that is subject to emission reduction requirements or limitations under CAAA Title IV.

(B) Applicants must have implemented one or more "qualified energy conservation measures" or have operational "qualified renewable energy generation" sources, or both, after January 1, 1992, and before December 31, 2000, or the date on which the relevant unit becomes an affected unit under Title IV. Allowances from the Reserve will be allocated based on emissions avoided from energy conservation or renewable energy generation.

(C) The conservation or renewable energy generation options implemented must be consistent with the applicant's least cost plan; and

(D) For utilities whose rates are regulated by a state regulatory authority, the state regulatory authority with jurisdiction over the electric rates of the applicant must have established rates and charges which guarantee net income neutrality. Such net income neutrality must be certified by the Secretary of the Department of Energy.

A utility that does not meet the above requirements is not eligible to apply for allowances in the Energy Conservation and Renewable Energy Reserve. The following definitions are provided to further clarify the above requirements: least cost plans, qualified energy conservation measures, qualified renewable energy generation, and net income neutrality.

Least Cost Plans

For purpose of the allowance reserve, "least cost plan" means a least cost energy conservation and electric power planning methodology, employed by an electric utility that evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost. These resources include, but are not limited to,

new power supplies, energy conservation and load management, and renewable resources. The plan must take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and treat demand-side and supply-side resources on a consistent and integrated basis. In addition, the least cost plan may take into account other factors, including the social and environmental costs and benefits of resource investments. The least cost plan must meet the following requirements:

(1) Involve a planning process that provides an opportunity for public notice and comment;

(2) Be submitted to the State regulatory authority for review on a regular basis or upon a utility's proposal to undertake supply- or demand-side activities;

(3) Be approved or filed with the regulatory authority in the State in which the qualifying conservation or renewable energy development takes place. Electric utilities not subject to the jurisdiction of a state regulatory authority must have such a plan or filing approved by the entity with ratemaking authority for such utility in the state in which the qualifying conservation or renewable energy development takes place; or in the event that there is no such authority, by EPA; and

(4) Upon approval, be implemented to the maximum extent practicable.

"Qualified" Energy Conservation Measure and Renewable Energy Generation

For purposes of this application, EPA defines "qualified energy conservation measures" and "qualified renewable energy generation" as follows:

A "qualified energy conservation measure" is a material or device installed by an electric utility in the home or facility of a customer to whom the electric utility provides electricity that:

(a) increases the efficiency of the use of electricity provided by the electric utility to the customer, thereby reducing electricity consumption compared to what it otherwise would have been, as measured in accordance with applicable state regulations or with the EPA Conservation Verification Protocol;

(b) is consistent with a least cost plan;

(c) does not increase the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or industrial waste gases;

(d) is paid for in whole or in part directly by the electric utility;

(e) does not result in any net increase in sulfur dioxide emissions from any affected unit owned or operated by the electric utility; and

(f) appears on the list of measures included as an appendix to this application, or which is a measure approved by the State regulatory authority which regulates the electric utility or, if the utility is not regulated by a State authority, the EPA Administrator.

Programs that are exclusively informational in nature, or load management (unless Kwh savings due to load shifting can be demonstrated by the electric utility) are not qualified energy conservation measures for purposes of the Reserve.

"Qualified renewable energy generation" is defined as electricity generation

derived from biomass, solar, geothermal, or wind resources, whose use does not provide a net increase in sulfur dioxide emissions; as defined below:

(a) biomass resources means energy-producing materials from biological sources, including wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste;

(b) solar resources means solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems; and grid and non-grid connected photovoltaic systems including photovoltaic systems added for voltage or capacity augmentation of a distribution grid;

(c) geothermal resources means hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity; and

(d) wind resources means grid and non-grid connected wind farms and individual wind-driven electrical generating turbines.

A list of qualified renewable energy generation sources is provided in Appendix B of these instructions. Programs that reduce electricity demand, or that appear on the list of qualified energy conservation measures provided in Appendix A are not considered renewable energy generation for purposes of the Reserve.

Net Income Neutrality

For purposes of the reserve, net income neutrality means, in the case of energy conservation measures undertaken by an electric utility whose rates are regulated by a State regulatory authority, rates and charges established by the State regulatory authority that ensure that the net income earned by the utility on the book value of its State-jurisdictional equity investment will be no lower as a consequence of its expenditures on qualified cost-effective energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures. EPA will forward applications to the Secretary of Energy to certify that the State regulatory authority with jurisdiction over the electric rates of the applicant that it has established rates and charges that guarantee that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the utility's conservation program.

Instructions for the Application for
Energy Conservation and Renewable Energy Reserve Allowances

I. APPLICATION INFORMATION

This application must be submitted to obtain allowances from the Conservation and Renewable Energy Reserve. Completed applications should be returned to:

U.S.E.P.A.
Acid Rain Division (ANR-445)
401 M Street, S.W.
Washington, D.C. 20460
Attn: Conservation and Renewable Energy Reserve

PAPERWORK REDUCTION ACT
The public reporting burden for this collection of information is estimated to average 80 hours per response including time for reviewing instructions, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding this burden estimate or any other aspects of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S.E.P.A. 401 M Street, S.W., Washington, D.C. 20460 Attn: Acid Rain Burden; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, D.C. 20603.

II. INSTRUCTIONS FOR COMPLETING THE APPLICATION

NOTE: Please type or print clearly in ink.

A. APPLICANT INFORMATION

AFFECTED UNIT NAME
List the name of the affected unit which the applicant owns or operates, in part or in whole.

AFFECTED UNIT ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER
Provide the allowance tracking system account number of the affected unit.

UTILITY NAME
Enter the name of the electric utility that owns or operates, in whole or in part, the affected unit. The applying utility may be, but is not required to be, the affected unit indicated above.

RESPONSIBLE OFFICIAL NAME
Enter the name of the individual who will act as the responsible official for the applicant. If, for any reason, the applying utility must change the official designated as responsible official before the application is processed or approved allowances are allocated, applicants must submit the new name to EPA at the above addresses.

STATE-REGULATED UTILITY
Indicate, by checking the correct box, if the applicant is rate-regulated by a State regulatory authority.

STATE
Indicate the state or territory in which the physical plant of the applicant is located.

ALLOWANCE TRACKING SYSTEM ACCOUNT NUMBER TO WHICH ALLOWANCES ARE TO BE ALLOCATED
Indicate the allowance tracking system account number to which the allocated allowances should be transferred. If the applicant does not have an account number, or wishes to open a new account for this purpose, leave this item blank, and submit a completed New Account Form/New Authorized Account Representative Form with this application. This form may be obtained by contacting EPA at the above address.

AUTHORIZED ACCOUNT REPRESENTATIVE SIGNATURE
If the allowances are to be transferred to an existing account, the Allowance Tracking System Account's Authorized Account Representative must sign the application here.

B. MEASURE INFORMATION

TYPE OF MEASURE(S) UNDERTAKEN
Indicate whether an energy conservation measure or a renewable energy generation measure, or both, was implemented. If the applicant implemented both conservation and renewable energy generation measures, two separate applications must be submitted.

MEASURE IDENTIFICATION
Identify the qualified energy conservation measure(s) implemented or the renewable energy generation source used for purposes of avoiding emissions during the previous year or years. "Qualified energy conservation measures" and "qualified renewable energy generation" are defined in the introduction to this application. Appendices A and B of the instructions to this application provide a list of qualified conservation and renewable energy sources, respectively.

Energy conservation measures that are not listed in Appendix A must be approved by the State regulatory authority that regulates the electric utility's electric rates, or, if the electric utility's rates are not regulated by a State authority, by the EPA Administrator, as indicated in Section D. Check the box provided if the energy conservation measure(s) implemented do not appear in Appendix A.

PROGRAM COST
Indicate the dollar amount spent on the conservation measure(s) or renewable energy generation implemented. The applicant must have paid for these measures, either directly or through purchase from another person.

TIME PERIOD
Enter the year or years over which sulfur dioxide emissions were avoided using the conservation and/or renewable energy measures identified above. These savings must have occurred after January 1, 1992, and before the earlier of December 31, 2000, or the date on which the unit owned or operated by the applying facility becomes an affected unit.

VERIFICATION OF CONSERVATION SAVINGS
For energy savings due to conservation

measures:

(A) List the amount of energy savings (in kilowatt hours) per measure per year.

(b) Indicate the methodology used to calculate the savings, and the person or affiliation who performed the calculation.

Utilities rate-regulated by a State regulatory authority must use the verification methodology of their State regulatory authority. EPA reserves the right to conduct audits to ascertain that the verification is valid and correct. Utilities not rate-regulated by a State regulatory authority must use the EPA Conservation Verification Protocol which is available from EPA at the address provided above.

VERIFICATION OF RENEWABLE ENERGY GENERATION

(i) For applications submitted on the basis of qualified renewable energy generation:

(a) Identify the size of the renewable generation facility (nameplate capacity in megawatts).

(b) List the amount of yearly qualified renewable energy generation (on a Btu basis)

(c) Indicate the hours of operation during a previous calendar year or years.

(d) Attach copies of plant operation records that demonstrate the above amounts.

(ii) For applications submitted on the basis of qualified renewable energy generation using hybrid generating facilities:

(a) Indicate the size of the hybrid generating facility (nameplate capacity in megawatts).

(b) List the quantity of renewable energy input (on a Btu basis) and the percent of electric generation that can be attributed to the renewable energy input.

(c) Attach copies of plant operation records that demonstrate these amounts.

ALLOWANCES REQUESTED

One allowance will be allocated for each ton of sulfur dioxide emissions avoided through the use of the conservation or renewable energy generation measure(s) during a calendar year or years within the period of applicability (January 1, 1992, to December 31, 2000 or the date on which the relevant unit owned or operated by the electric utility becomes an affected unit). These savings are calculated as follows:

(i) For savings from qualified energy conservation measures, the avoided emission tonnage is equal to the product of:

$$\frac{(A) \times (B)}{2000 \text{ lbs.}},$$

where (A) = the kilowatt hours that were not, but would otherwise have been supplied by the utility during such year(s) in absence of the qualified energy conservation measures; and (B) = 0.004 lbs. per kilowatt hour. The equation should be rounded to the nearest ton.

(ii) For savings from qualified renewable energy generation, the avoided emission tonnage is equal to the product of:

$$\frac{(A) \times (B)}{2000 \text{ lbs.}},$$

where (A) = the actual kilowatt hours generated by, or purchased from, qualified renewable energy based on the renewable energy input at a facility; and (B) = 0.004 lbs. per kilowatt hour. The equation should be rounded to the

nearest ton.

Allowances will not be allocated for savings to be accrued in future years.

C. APPROVAL OF LEAST COST PLAN

The applicant must have an approved least cost plan, as defined in the introduction to this application. For utilities rate-regulated by a State regulatory authority, plans must be approved by the State regulatory authority. For utilities not rate-regulated by a State regulatory authority, plans must be approved by the entity with rate-making authority for the applicant. If the electric utility is not regulated by a State regulatory or other rate-making authority, the EPA Administrator must approve the least cost plan.

The entity approving the least cost plan must also certify that the measures implemented are consistent with the findings of the least cost plan.

SIGNATURE
The signature must be that of the reviewing official.

DATE
Indicate the date on which the application was certified by the reviewing official.

D. CERTIFICATION BY REGULATORY AUTHORITY

The application must be reviewed by the entity with ratemaking authority for the utility, or, in the case of an application submitted by a utility not rate-regulated by a State authority, EPA.

SIGNATURE
For electric utilities rate-regulated by a State regulatory authority, the signature must be that of a member of such State regulatory body. For electric utilities not rate-regulated by a State authority, the EPA Administrator will make the certification. In such a case, leave this section blank.

DATE
Indicate the date on which the form was signed by the regulatory entity.

E. DEMONSTRATION AND CERTIFICATION OF NET INCOME NEUTRALITY

For State-regulated investor-owned electric utilities implementing conservation measures: To demonstrate net income neutrality, attach a copy of a State regulatory filing describing the approved ratemaking mechanisms that guarantee that the utility's net income will be at least as high upon implementation of conservation measures as it would have been otherwise.

Upon application approval, EPA will forward applications from investor-owned State-regulated utilities implementing conservation measures to the Secretary of Energy to certify that the State regulatory authority with jurisdiction over the rates of the applicant has established rates and charges that ensure net income neutrality.

SIGNATURE
The signature must be that of the Secretary of Energy or and official representative.

DATE
Indicate the date on which the Secretary

of Energy certifies that the application is net income neutral.

F. CERTIFICATION OF RESPONSIBLE OFFICIAL

SIGNATURE
The signature must be that of the responsible official indicated in section A above.

DATE
Indicate the date on which the form was signed by the responsible official

III. GENERAL INFORMATION

This section provides additional information on the Energy Conservation and Renewable Energy Reserve Program. For a complete description of the allowance program mandated by Sections 404 and 416 of the Clean Air Act Amendments, see 40 CFR Part 73.

Remittance: EPA will accept applications for allowances from the Energy Conservation and Renewable Energy Reserve beginning no earlier than January 1, 1993, and ending on January 2, 2010, or until all of the allowances in the reserve have been allocated. Applicants may apply for allowances on a yearly basis or less frequently for emissions avoided in a previous year or years from qualified energy conservation measures or qualified renewable energy generation.

Processing and Approval: Applications received by EPA will be processed and approved on a first-come, first-served basis, except that EPA will not allocate more than a total of 30,000 allowances in connection with applications based on any one of the following four categories of qualified renewable energy: (1) biomass; (2) solar; (3) geothermal; and (4) wind.

The Administrator will return applications that fail to meet the application requirements within five business days of receipt. Resubmitted applications will be processed according to the postmark on the revised application.

Within 45 days of receipt, applications that meet the application requirements will be approved, or conditionally approved pending certification of the Secretary of Energy if the applicant is a State rate-regulated utility implementing conservation measures.

Allocation of Allowances: Allowances from the Reserve will be transferred into a single Allowance Tracking System Account at the time of approval or partial approval of the application, provided that a sufficient number of allowances remain in the Reserve at that time. The allowances may be transferred into an existing account if the application is signed by the Authorized Account Representative, or, into a new account if a completed New Account/New Authorized Account Representative Form accompanies the application.

Allowances from the Reserve are spot allowances that may be used for purposes of compliance beginning in the year they are allocated.

Establishment of a Reserve subaccount: The Administrator shall review the distribution of allowances from the Reserve when 240,000 of the 300,000 allowances have been allocated. If the Administrator finds that fewer

than 60,000 allowances have been allocated for each of (1) qualifying energy conservation measures or (2) qualifying renewable energy generation, a subaccount will be established for the allocation of allowances to applicants implementing such measures. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

Unless all of the allowances in the subaccount are allocated earlier, the Administrator will terminate the subaccount not later than February 1, 1998, and return any remaining allowances to the Reserve.

Application for Energy Conservation and Renewable Energy Reserve Allowances

A. Applicant Information

Affected Unit Name _____

Affected Unit Allowance Tracking System Account _____

Utility Name _____

Responsible Official Name _____

Applicant is Rate-Regulated by a State Regulatory Authority (check one)

Yes ☐ No ☐

State in which Utility is Located _____

Allowance Tracking System Account
to which Allowances are to be Allocated _____

Signature of Authorized Account Representative _____

B. Measure Information

Type of Measure(s) Undertaken (check one)

Conservation ☐ Renewable Energy ☐

Measure Identification _____

_____

Conservation measure is not on List A ☐

Program Cost _____

Time Period (Year/s) _____

Verification of Conservation Savings

a. Kilowatt hours saved _____

b. Methodology Used _____

Verification of Renewable Energy Generation

a. Nameplate Capacity (megawatts) _____

b. Energy Generation (Btus and % of Total) _____

c. Hours operated per Year _____

d. Attach copies of plant operation records verifying these numbers.

Allowances Requested _____

For Official Use Only

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C. Approval of Least Cost Plan by Ratemaking Authority

I certify that, as an official representative of the State regulatory authority or ratemaking entity of the applicant, the following criteria have been meet:

(1) The applicant's least cost plan has been approved by the authority; and
(2) The energy conservation and/or renewable energy generation measure(s) implemented by the utility are consistent with the findings in the least cost plan.

Certifying Official Signature _____

Name of Regulatory Body _____

Notary Public Signature _____

Date _____

D. Certification

I certify, as an official representative of the rate regulatory authority of the applicant, or of the U.S.E.P.A., that:

(1) I have reviewed this application and find it to be accurate and complete; and
(2) (as applicable) I have determined, according to my best profession judgement, that the energy conservation measure(s) implemented by the applicant that are not listed in Appendix A of the instructions of this application are qualified energy conservation measure(s).

Certifying Official Signature _____

Name of Regulatory Body _____

E. Demonstration of Net Income Neutrality
(for state rate-regulated utilities only)

Applicants must attach a copy of a regulatory filing describing the approved rulemaking mechanisms that guarantee net income neutrality.

Certification of Net Income Neutrality

- I certify that the state regulatory authority with jurisdiction over the electric rates of the applicant has established rates and charges that ensure net income neutrality.

Secretary of Energy Signature _____

Date _____

F. Certification of Responsible Official

I submit this form pursuant to EPA's regulations governing the allocation of allowances in the energy conservation and renewable energy reserve. I certify that the electric utility owns or operates, in whole or in part, an affected unit, and that qualified energy conservation or renewable energy generation measure(s) were implemented consistent with the utility's approved least cost plan. I further certify that the information provided in this form is true and correct

Responsible Official Signature _____

Notary Public Signature _____

Date _____

APPENDIX B TO SUBPART F - List of Qualified Energy Conservation Measures

1. *Demand-side measures Applicable for the Conservation and Renewable Energy Reserve Program or Reduced Utilization.*

The following listed measures are approved as "qualified energy conservation measures" for purposes of the Conservation and Renewable Energy Reserve Program or Reduced Utilization. Measures not appearing on the list may also be approved if it is demonstrated that they meet the criteria specified in §73.81(a) of the regulations.

1.1 RESIDENTIAL

1.1.1 Space Conditioning

- o Electric furnace improvements (intermittent ignition, automatic vent dampers, and heating element change-outs)
- o Air conditioner (central and room) upgrades/replacements
- o Heat pump (ground source, solar assisted, and conventional) upgrades/replacements
- o Cycling of air conditioners and heat pumps
- o Natural ventilation
- o Heat recovery ventilation
- o Thermal energy storage
- o Clock thermostats
- o Setback thermostats
- o Geothermal steam direct use
- o Improved equipment controls
- o Solar assisted space conditioning (ventilation, air-conditioning, and desiccant cooling)
- o Passive solar designs
- o Air conditioner and heat pump clean and tune-up
- o Heat pipes
- o Whole house fans
- o High efficiency fans and motors
- o Hydronic pump insulation
- o Register relocation
- o Register size and blade configuration
- o Return air location
- o Duct sizing
- o Duct insulation
- o Duct sealing
- o Duct cleaning
- o Shade tree planting

1.1.2 Water Heating

- o Electric water heater upgrades/replacements
- o Electric water heater tank wraps/blankets
- o Low-flow showerheads and fittings
- o Solar heating and pre-heat units
- o Geothermal heating and pre-heat units
- o Heat traps
- o Water heater heat pumps
- o Recirculation pumps
- o Setback thermostats
- o Water heater cycling control
- o Solar heating for swimming pools
- o Pipe wrap insulation

1.1.3 Lighting

- o Lamp replacement
- o Dimmers
- o Motion detectors and occupancy sensors
- o Photovoltaic lighting
- o Fixture replacement
- o Outdoor lighting controls

1.1.4 Building Envelope

- o Attic, basement, ceiling, and wall insulation
- o Passive solar building systems
- o Exterior roof insulation
- o Exterior wall insulation
- o Exterior wall insulation bordering unheated space (e.g., a garage)
- o Knee wall insulation in attic
- o Floor insulation
- o Perimeter insulation
- o Storm windows/doors
- o Caulking/weatherstripping
- o Multi-glazed inserts for sliding glass doors
- o Sliding door replacements
- o Installation of French doors
- o Hollow core door replacement
- o Radiant barriers
- o Window vent conversions
- o Window replacement
- o Window shade screens
- o Low-e windows
- o Window reduction
- o Attic ventilation
- o Whole house fan

- o Passive solar design

1.1.5 Other Appliances

- o Refrigerator replacements
- o Freezer replacements
- o Oven/range replacements
- o Dishwasher replacements
- o Clothes washer replacements
- o Clothes dryer replacements
- o Customer located power generation based on photovoltaic, solar thermal, biomass, wind or geothermal resources
- o Swimming pool pump replacements
- o Gasket replacements
- o Maintenance/coil cleaning

1.2 COMMERCIAL

1.2.1 Heating/Ventilation/Air Conditioning (HVAC)

- o Heat pump replacement
- o Fan motor efficiency
- o Resizing of chillers
- o Heat pipe retrofits in air conditioning units
- o Dehumidifiers
- o Steam trap insulation
- o Radiator thermostatic valves
- o Variable speed drive on fan motor
- o Thermal storage
- o Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- o HVAC piping insulation
- o HVAC ductwork insulation
- o Boiler insulation
- o Automatic night setback
- o Automatic economizer cooling
- o Outside air control
- o Hot and cold deck automatic reset
- o Reheat system primary air optimization
- o Process heat recovery
- o Deadband thermostat
- o Timeclocks on circulating pumps
- o Chiller system
- o Increase condensing unit efficiency
- o Separate make-up air for exhaust hoods

- o Variable air volume system
- o Direct tower cooling (chiller strainer cycle)
- o Thermal storage
- o Multiple chiller control
- o Radiant heating
- o Evaporative roof surface cooling
- o Cooling tower flow control
- o Ceiling fans
- o Evaporative cooling
- o Direct expansion cooling system
- o Heat recovery ventilation (water and air-source)
- o Set-back controls for heating/cooling
- o Make-up air control
- o Manual fan switches
- o Energy saving exhaust hood
- o Night flushing
- o Spot radiant heating
- o Terminal regulated air volume control scheme
- o Variable speed motors for HVAC system
- o Waterside economizers
- o Airside economizer
- o Gray water systems
- o Well water for cooling

1.2.2 Building envelope

- o Insulation
- o Wall insulation
- o Floor/slab insulation
- o Roof insulation
- o Window and door upgrades, replacements, and films (to reduce solar heat gains)
- o Passive solar design
- o Earth berming
- o Shading devices and tree planting
- o High reflectivity roof coating
- o Evaporative cooling
- o Infiltration reduction
- o Weatherstripping
- o Caulking
- o Low-e windows
- o Multi-glazed windows
- o Replace glazing with insulated walls
- o Thermal break window frames
- o Tinted glazing

- o Vapor barrier
- o Vestibule entry

1.2.3 Lighting

- o Electronic ballast replacements
- o Delamping
- o Reflectors
- o Occupancy sensors
- o Daylighting with controls
- o Photovoltaic lighting
- o Efficient exterior lighting
- o Manual selective switching
- o Efficient exit signs
- o Daylighting construction
- o Cathode cutout ballasts
- o High intensity discharge luminaries
- o Outdoor light timeclock and photocell

1.2.4 Refrigeration

- o Refrigerator replacement
- o Freezer replacement
- o Optimize heat gains to refrigerated space
- o Optimize defrost control
- o Refrigeration pressure optimization control
- o High efficiency compressors
- o Anti-condensate heater control
- o Floating head pressure
- o Hot gas defrost
- o Parallel unequal compressors
- o Variable speed compressors
- o Water cooler controls
- o Waste heat utilization
- o Air doors on refrigeration equipment

1.2.5 Water Heating

- o Electric water heating upgrades/replacements
- o Electric water heater wraps/blankets
- o Pipe insulation
- o Solar heating and/or pre-heat units
- o Geothermal heating and/or pre-heat units
- o Circulating pump control
- o Point-of-use water heater
- o Heat recovery DHW system
- o Chemical dishwashing system

- o End-use reduction using low-flow fittings

1.2.6 Other end-uses and miscellaneous
- o Energy management control systems for building operations
- o Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- o Energy efficient office equipment
- o Customer-owned transformer upgrades and proper sizing

1.3 INDUSTRIAL

1.3.1 Motors
- o Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed or variable frequency drives
- o Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- o Install self-starters
- o Replace improperly sized motors

1.3.2 Lighting
- o Electronic ballast replacement/improvement
- o Electromagnetic ballast upgrade
- o Installation of reflectors
- o Substitution of lamps with built-in automatic cathode cut-out switches
- o Modify ballast circuits with additional impedance devices
- o Metal halide and high pressure sodium lamp retrofits
- o High pressure sodium retrofits
- o Daylighting with controls
- o Occupancy sensors
- o Delamping
- o Photovoltaic lighting
- o Two step and dimmable high intensity discharge ballast

1.3.3 Heating/Ventilation/Air Conditioning (HVAC)
- o Heat pump replacement/upgrade
- o Furnace upgrade/replacement
- o Fan motor efficiency
- o Resizing of chillers
- o Heat pipe retrofits on air conditioners
- o Variable speed drive on fan motor

- o Thermal storage
- o Solar assisted HVAC including ventilation, chillers, heat pumps and desiccants

1.3.4 Industrial Processes

- o Upgrades in heat transfer equipment
- o Insulation and burner upgrades for industrial furnaces/ovens/boilers to reduce electricity loads on motors and fans
- o Insulation and redesign of piping
- o Upgrades/retrofits in condenser/evaporation equipment
- o Process air and water filtration for improved efficiency
- o Upgrades of catalytic combustors
- o Solar process heat
- o Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- o Power factor controllers
- o Utilization of waste by-product fuels
- o Steam line and steam trap repairs/upgrades
- o Compressed air system improvements/repairs
- o Industrial process heat pump
- o Optimization of equipment lubrication or maintenance
- o Resizing of process equipment for optimal energy efficiency
- o Use of unique thermodynamic power cycles

1.3.5 Building Envelope

- o Insulation of ceiling, walls, and ducts
- o Window and door replacement/upgrade, including thermal energy barriers
- o Caulking/weatherstripping

1.3.6 Water Heating

- o Electric water heater upgrades/replacements
- o Electric water heater wraps/blankets
- o Pipe insulation
- o Low-flow showerheads and fittings
- o Solar heating and pre-heat units
- o Geothermal heating and pre-heat units

1.3.7 Other End-uses and miscellaneous

- o Refrigeration system retrofit/replacement
- o Energy management control systems and end use metering
- o Customer-owned transformer retrofits/replacements and proper

sizing

1.4 AGRICULTURAL

1.4.1 Space Conditioning

- o Building envelope measures
- o Efficient HVAC equipment
- o Heat pipe retrofit on air conditioners
- o System and control measures
- o Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- o Air-source and geothermal heat pumps replacement/upgrades

1.4.2 Water heating

- o Upgrades/replacements
- o Water heater wraps/blankets
- o Pipe insulation
- o Low-flow showerheads and fittings
- o Solar heating and/or pre-heat units
- o Geothermal heating and/or pre-heat units

1.4.3 Lighting

- o Electronic ballast replacements
- o Delamping
- o Reflectors
- o Occupancy sensors
- o Daylighting with controls
- o Photovoltaic lighting
- o Outdoor lighting controls

1.4.4 Pumping/Irrigation

- o Pump upgrades/retrofits
- o Computerized pump control systems
- o Irrigation load management strategies
- o Irrigation pumping plants
- o Computer irrigation control
- o Surge irrigation
- o Computerized scheduling of irrigation
- o Drip irrigation systems

1.4.5 Motors

- o Retire inefficient motors and replace with energy efficient motors,

including the use of electronic adjustable speed and variable frequency drives
- o Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- o Install self-starters
- o Replace improperly sized motors

1.4.6 Other end uses
- o Ventilation fans
- o Cooling and refrigeration system upgrades
- o Grain drying using unheated air
- o Grain drying using low temperature electric
- o Customer-owned transformer retrofits/replacements and proper sizing
- o Programmable controllers for electrical farm equipment
- o Controlled livestock ventilation
- o Water heating for production agriculture
- o Milk cooler heat exchangers
- o Direct expansion/ice bank milk cooling
- o Low energy precision application systems
- o Heat pump crop drying

1.5 GOVERNMENT SERVICES SECTOR

1.5.1 Streetlighting
- o Replace incandescent and mercury vapor lamps with high pressure sodium and metal halide

1.5.2 Other
- o Energy efficiency improvements in motors, pumps, and controls for water supply and waste water treatment
- o District heating and cooling measures derived from cogeneration that result in electricity savings

2. *Supply-side Measures Applicable for Reduced Utilization.*

In addition to the measures specified in (a), the following supply-side measures may be approved for purposes of reduced utilization qualified energy conservation plans under § 72.43:

2.1 Generation efficiency
- o Heat rate improvement programs
- o Availability improvement programs

- o Coal cleaning
- o Turbine improvements
- o Boiler improvements
- o Control improvements, including artificial intelligence and expert systems
- o Distributed control - local (real-time) versus central (delayed)
- o Equipment monitoring
- o Performance monitoring
- o Preventive maintenance
- o Additional or improved heat recovery
- o Sliding/variable pressure operations
- o Adjustable speed drives
- o Improved personnel training to improve man/ machine interface

2.2 Transmission and distribution efficiency

- o High efficiency transformer switchouts using amorphous core and silicon steel technologies
- o Low-loss windings
- o Innovative cable insulation
- o Reactive power dispatch optimization
- o Power factor control
- o Primary feeder reconfiguration
- o Primary distribution voltage upgrades
- o High efficiency substation transformers
- o Controllable series capacitors
- o Real-time distribution data acquisition analysis and control systems
- o Conservation voltage regulation

3. *Renewable energy generation measures applicable for the Conservation and Renewable Energy Reserve Program.*

The following listed sources are approved as "qualified renewable energy generation " for purposes of the Conservation and Renewable Energy Reserve Program. Sources not appearing on the list may be approved if it is demonstrated that they meet the criteria specified in §73.81(c) of the regulations.

3.1 Biomass resources

- o Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, and energy crops, and eligible components of municipal solid waste.

3.2 Solar resources

- o Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
- o Grid and non-grid connected photovoltaic systems, including systems

added for voltage or capacity augmentation of a distribution grid.

3.4 Geothermal resources

- o Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.

3.5 Wind resources

- o Grid-connected and non-grid-connected wind farms
- o Individual wind-driven electrical generating turbines

PART 75 -- CONTINUOUS EMISSION MONITORING

Sec.

Subpart A - General

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APPENDIX A - SPECIFICATIONS AND TEST PROCEDURES

APPENDIX B - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

APPENDIX C - MISSING DATA STATISTICAL ESTIMATION PROCEDURES

APPENDIX D - OPTIONAL SO_2 EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

APPENDIX E - CONVERSION PROCEDURES

[Authority: Secs. 412 and 821, Pub.L. 101-549, 104 Stat. 2624, 2699]

Subpart A - General

§ 75.1 Purpose

(a) This part establishes requirements for the installation, operation, maintenance, and certification of continuous emission monitoring systems for the measurement, recording, and standardized electronic reporting of SO_2 and NO_x emissions, volumetric flow, and opacity data from Phase I and Phase II affected units under Title IV of the Act. Requirements for alternative monitoring systems and for the

quality assurance and quality control of continuous emission monitoring data also are established.

(b) This part also establishes requirements for the monitoring and reporting of CO_2 emissions pursuant to § 821 of the Act.

§ 75.2 Definitions

The terms used in this part are defined in the Act or in this section as follows.

Accuracy means the closeness of the measurement made by a continuous emission monitoring system, a pollutant concentration monitor or a flow monitor to the true value of the emissions or volumetric flow. It is expressed as the difference between the measurement and a reference method value, which is assumed to be equivalent to the true value. Variation among these differences represents the variation in accuracy which could be caused by random or systematic error.

Acid Rain Program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to Title IV of the Act under 40 CFR Parts 72-78.

Act means the Clean Air Act, 42 U.S.C. §7401, et seq., as amended by Pub. L. 101-549, November 15, 1990.

Administrator means the Administrator of the United States Environmental Protection Agency (EPA) or the Administrator's duly authorized representative.

Affected unit means a unit or source that is subject to any emission reduction requirement or limitation under the Acid Rain Program, or a unit or source that opts-in under 40 CFR Part 74.

Alternative monitoring system means a system designed to provide direct or indirect determinations of mass per unit time emissions, pollutant concentrations, and/or volumetric flow data that are demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a continuous emission monitoring system.

As-fired means the taking of a fuel sample just prior to its introduction into the boiler for combustion.

Available means the continuous emission monitoring system or continuous opacity monitoring system is functional and operating within the calibration error and other applicable performance specifications.

Bias means systematic error. The result of bias is that measurements will be either consistently low or high relative to the true value.

Boiler means a fossil or other fuel-fired combustion device used to produce heat and to transfer heat to water, steam, or through another medium.

By-pass means any duct, stack, or conduit through which emissions from an affected unit may or do pass to the

atmosphere, which either augments or substitutes for the principal ductwork and stack exhaust system during any portion of the unit's operation.

Calibration error means the difference between (1) the response of a gaseous monitor to a calibration gas and the known concentration of the gas, (2) the response of a flow monitor to a reference signal and the known value of the reference signal, or (3) the response of a continuous opacity monitoring system to an attenuation filter and the known value of the filter after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Calibration gas means for the purposes of this part, a known concentration of a gas (1) that is traceable to either a standard reference material gas or a National Institute of Standards and Technology (NIST)/EPA-approved certified reference material gas or (2) that is a Protocol 1 gas. A gas that is traceable to a gas manufacturer's intermediate standard is not a calibration gas for the purposes of this part.

Centroidal area means a concentric area that is geometrically similar to the stack or duct cross section and is not greater than 1 percent of the stack or duct cross-sectional area.

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel, alone or in combination with any other fuel, independent of the percentage of coal consumed on a Btu basis.

Commence construction means that an owner or operator has undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commence operation means to have begun the combustion of fuel in the unit's combustion chamber.

Commence commercial operation means to have begun to generate electricity for sale, including test generation.

Common stack means the exhaust of two or more units through a single flue in a single stack.

Construction means fabrication, erection, or installation of an affected unit.

Continuous means capable of obtaining a sample at least every 15 min.

Continuous emission monitoring system means the equipment required by this part used to sample, analyze, measure, and provide, on a continuous basis, a permanent record of emissions and volumetric flow expressed in pounds per hour (lb/hr) for sulfur dioxide, in standard cubic feet per hour (scfh) for volumetric flow, and in pounds per

million Btu (lb/mmBtu) of heat input for nitrogen oxides. The following systems are component parts included in a "continuous emission monitoring system": (1) sulfur dioxide pollutant concentration monitor, (2) flow monitor, (3) nitrogen oxides pollutant concentration monitor, (4) diluent gas monitor (oxygen or carbon dioxide), and (5) data acquisition and handling system. A continuous moisture monitor may also be included.

Continuous opacity monitoring system means the equipment used to sample, measure, analyze, and provide, on a continuous basis, a permanent record of opacity or transmittance.

Data acquisition and handling system means that component of the continuous emission monitoring system designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, and other components of the continuous emission monitoring system to produce a continuous readout of the measured parameters in units required by this part.

Designated representative means a natural person authorized by the owners and operators of a source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with 40 CFR Part 72, Subpart B, to represent and legally bind the owners and operators jointly and severally as a matter of

Federal law in all matters relating to the Acid Rain Program. Except for § 72.20(c), the term "designated representative" shall also mean any natural person designated in accordance with 40 CFR Part 72 as an alternative designated representative to act on behalf of the person authorized in accordance with the preceding sentence. Whenever the term "responsible official" is used in 40 CFR Part 70 or Part 71 or in a State operating permit program, it shall be deemed to refer to the "designated representative" as defined here insofar as Acid Rain Program actions, standards, requirements, or prohibitions are concerned.

Diluent gas means a major gaseous constituent in a gaseous pollutant mixture. For combustion sources, carbon dioxide and oxygen are the major diluent gases.

Dual span system means a pollutant concentration monitor, flow monitor, or opacity monitor that has two ranges of values over which measurements are made.

Equivalent diameter means a calculated value used to determine the upstream and downstream distances for locating flow or pollutant concentration monitors in ducts or stacks with rectangular cross sections. The equation in paragraph 2.1 of Method 1 in 40 CFR Part 60, Appendix A, is used to determine equivalent diameter.

Excess emissions of opacity means the measured opacity during any 6-minute period or other State-promulgated and approved averaging period when the applicable Federal or State opacity limit, whichever is more restrictive, is exceeded.

Existing unit means a unit (including units subject to Section 111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990, and that is modified, reconstructed, or repowered after November 15, 1990, shall continue to be an existing unit. Existing units do not include simple combustion turbines or units that serve only a generator with a nameplate capacity of 25 megawatt electrical output or less.

Flow monitor means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas from an affected unit or source.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Gas-fired means the combustion of natural gas for 90 percent or more of the annual heat input and of fuel oil (including diesel fuel) for the remaining heat input.

Gas manufacturers intermediate standard means a compressed (cylinder) gas standard that has been assayed

with direct reference to a standard reference material gas or NIST/EPA-approved certified reference material and that has been certified by, and met all other requirements of, "Revised Traceability Protocol No. 1."

Limited life means any affected unit that permanently ceases operation before January 1 of the first year for which it is required, under Title IV of the Act, to hold allowances to account for its emissions of sulfur dioxide.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 megawatt electrical output or less or a simple combustion turbine.

Ninetieth (90th) percentile means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value.

NIST/EPA-approved certified reference material means a reference material one or more of whose property values are certified by a technically valid procedure, accompanied by or traceable to a certificate or other documentation that is issued by a certifying body and approved by EPA. A current list of certified reference material cylinder gases and certified reference material vendors is available from the Quality Assurance Division (MD-77), Environmental Monitoring

Systems Laboratory, U.S. EPA, Research Triangle Park, NC 27711.

Oil-fired means the combustion of fuel oil (including diesel fuel) for more than 10 percent of the annual heat input and natural gas and no other fuels for the remaining heat input.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operational period means a minimum period of time over which a measurement system is expected to operate within certain performance specifications set forth in Appendix A of this part without unscheduled maintenance, repair, or adjustment.

Out-of-control period means any period beginning with the hour that a daily calibration error or electronic drift or quality assurance audit begins that indicates that the instrument is not measuring and recording within the appropriate performance specifications except as specifically provided in this part. The end of the period is the hour corresponding to the completion of an additional calibration error or electronic drift check or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the appropriate performance specifications.

Owner means any of the following persons: (1) any holder of any portion of the legal or equitable title on an affected unit; (2) any holder of a leasehold interest in an affected unit; or (3) any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in Section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, "owner" does not include a passive lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or operator means any person who is an owner or who operates, controls, or supervises in any way an affected unit or an affected source of which an affected unit is a part and includes but is not limited to any holding company, operating company, utility systems, designated representative, or plant manager of an affected unit or affected source.

Path continuous emission monitoring system means a continuous emission monitoring system that measures the pollutant concentration along a path greater than 10 percent of the equivalent diameter of the stack or duct cross section.

Permitting authority means either of the following: (1) the Administrator in the case of EPA implementation of

the Acid Rain Program; or (2) the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under Titles IV and V of the Act and 40 CFR Part 70 and Part 72, Subpart I.

Point continuous emission monitoring system means a continuous emission monitoring system that measures the pollutant concentration either at a single point or along a path equal to or less than 10 percent of the equivalent diameter of the stack or duct cross section.

Pollutant concentration monitor means that component of the continuous emission monitoring system that measures unit exhaust gas pollutant concentration.

Precision means the closeness of a measurement to the actual measured value expressed as the uncertainty associated with repeated measurements of the same sample or of different samples from the same process (e.g., the random error associated with simultaneous measurements of a process made by more than one instrument). A measurement technique is determined to have increasing precision as the variation among the repeated measurements decreases.

Protocol 1 gas means a calibration gas mixture prepared and analyzed according to "Revised Traceability Protocol No. 1" (see "Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and

Audit of Continuous Emission Monitors," Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods, Section 3.04, EPA-600/4-77-027b, June 1987). The certified concentrations for calibration gas mixtures developed using "Revised Traceability Protocol No. 1" are traceable to a standard reference material or an NIST/EPA-approved certified reference material.

Qualifying Phase I technology means a technological system of continuous emission reduction that is demonstrated to achieve a 90-percent reduction in emissions of sulfur dioxide from the emissions that would have resulted from the combustion of fossil fuels that were not subject to treatment prior to combustion, as provided in 40 CFR Part 72.42.

Reference method means any method of sampling and analyzing for an air pollutant as specified in 40 CFR Part 60, Appendix A.

Reference value means the known concentration of a calibration gas certified to a standard reference material.

Relative accuracy means, in general, a statistic designed to provide a measure of the systematic and random errors associated with data from continuous emission monitoring systems. Specifically, "relative accuracy" is the absolute mean difference between the pollutant

concentration or volumetric flow determined by the continuous pollutant or flow monitoring system and the value determined by the appropriate reference methods plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests.

Span means the range of values that can be measured by a continuous emission monitoring system.

Standard reference material means a reference material distributed and certified by the National Institute of Standards and Technology.

Standard absolute pressure means 29.92 in. of mercury or 760 mm of mercury.

Standard absolute temperature means 20 °C, 293 °K, 68 °F, or 528 °R.

Standard conditions means 68 °F at 1 atm (29.92 in. of mercury).

State means one of the 48 contiguous States and the District of Columbia and includes all non-Federal authorities, including local agencies, interstate associations, tribal authorities, and State agencies with approved permit programs under 40 CFR Part 70. The term "State" also encompasses those Native American governing bodies that the Administrator has determined, pursuant to Section 301(d) of the Act, to treat as States.

Substitute data means emissions or volumetric flow data provided to assure 100 percent recording and reporting of emissions when all or part of the continuous emission monitoring system is not functional or is operating outside applicable performance specifications.

Substitution unit means an affected unit that is listed in 40 CFR Part 72, Appendix B, and is designated as a Phase I affected unit in a substitution plan under 40 CFR Part 72.41.

Uncontrolled emission rate means the maximum hourly pollutant emission rate of sulfur dioxide or nitrogen oxides emitted during the previous 365 days for an affected unit. Where no previous continuous emission monitoring data exist for sulfur dioxide, the "uncontrolled emission rate" means the maximum possible emission rate, calculated as the product of the maximum sulfur content of the fuel used and the maximum fuel feed rate of the unit at full generating capacity. Where no previous continuous emission monitoring data exist for nitrogen oxides, the "uncontrolled emission rate" is calculated based on the operating parameters of the affected unit and equations in "Compilation of Air Pollutant Emission Factors" (Volume I: Stationary Point and Area Sources, AP-42, fourth edition, September 1985, and applicable supplements).

Unit means a fossil fuel-fired combustion device.

Unit operating hours means, in reference to continuous emission monitoring system availability, the number of hours that a unit (boiler) combusts any fuel.

Utility unit means a unit owned or operated by a utility (1) that serves a generator that produces electricity for sale, or (2) that during 1985, served a generator that produced electricity for sale. Notwithstanding paragraphs (1) and (2) above, a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale is not a "utility unit" for the purposes of the Acid Rain Program. Notwithstanding paragraphs (1) and (2) above, a unit that cogenerates steam and electricity is not a utility unit for the purposes of the Acid Rain Program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990, and supplies, more than one-third of its potential electric output capacity and more than 25 megawatt electrical output to any utility power distribution system for sale.

§ 75.3 Units and abbreviations

(a) The abbreviations and symbols of units of measure used in this part are defined as follows.

Btu - British thermal unit

°C - degree Celsius (centigrade)

cfm - cubic feet per minute

cm - centimeter

dcf - dry cubic feet

dscf - dry cubic feet at standard conditions

dscfh - dry cubic feet per hour at standard conditions

eq - equivalent

°F - degree Fahrenheit

fps - feet per second

gal - gallon

hr - hour

lb - pound

m - meter

mmBtu - million Btu

min - minute

mol. wt. - molecular weight

MWe - megawatt electrical

MWge - gross megawatt electrical

ppm - parts per million

°R - degree Rankine

scf - cubic feet at standard conditions

scfh - cubic feet per hour at standard conditions

sec - second

std - at standard conditions

(b) Chemical nomenclature include:

CO_2 - carbon dioxide

NO_x - nitrogen oxides

O_2 - oxygen

SO_2 - sulfur dioxide

§ 75.4 Addresses

(a) Except as specified in paragraph (d) of this section, all requests for certification or recertification, applications for alternative monitoring systems, notifications, electronic reports, and other communications to the Administrator required by §§ 75.18, 75.21, or 75.23 shall be submitted to the Chief, Emissions Monitoring Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, DC 20460.

(b) Acid Rain Program plant and unit identification numbers (for the Aerometric Information Retrieval System) required by § 75.23(a) are listed in Appendices A and B of 40 CFR Part 72. They may also be obtained from the Chief, Allowance Tracking Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, at the address given in paragraph (a) of this section.

(c) Copies of requests for initial certification or recertification of a continuous emission monitoring system required by § 75.23(c) shall be submitted to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices. A copy of

the documentation also shall be submitted to the appropriate State air pollution control agency.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Air Management Division, U.S. Environmental Protection Agency, John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air, Pesticides and Toxics Division, U.S. Environmental Protection Agency, 345 Courtland Street, N.E., Atlanta, Georgia 30365.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), Director, Air, Pesticides, and Toxics Division, U.S. Environmental Protection Agency, 1445 Robs Avenue, Dallas, Texas 75202.

Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, Missouri 66101.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 999 18th Street, Suite 500, Denver, Colorado 80202-2405.

Region IX (Arizona, California, Guam, Hawaii, Nevada), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94103.

Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101.

(d) The acid rain continuous emission monitoring information and opacity reports required by §§ 75.23(a) and 75.23(g) shall be submitted to the applicable permitting authority at the following address.

State of Alabama, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, AZ 85007.

State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of California, Air Resources Board, 1102 Q Street, Sacramento, CA 95814.

State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, CO 80220.

State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 614 M Street, N.W., Washington DC 20001.

State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.

State of Iowa, Iowa Department of Natural Resources, Air Quality and Solid Waste Protection Bureau, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Waste Management, Forbes Field, Topeka, Kansas 66620.

State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.

991600

State of Maryland, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.

State of Minnesota, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of Mississippi, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of Missouri, Department of Natural Resources, Air Pollution Control Program, P.O. Box 176, Jefferson City, Missouri 65102.

State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of Nebraska, Department of Environmental Control, Air Quality Division, P.O. Box 98922, State House Station, Lincoln, Nebraska 68509-8922.

State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of New Hampshire, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of New Jersey, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.

State of New Mexico, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of New York, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.

State of North Carolina, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

993602

State of Ohio, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus, Ohio 43266-0149.

State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of Oregon, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.

Commonwealth of Pennsylvania, Department of Environmental Resources, 105 S. Second Street, P.O. Box 2357, Harrisburg, Pennsylvania 17120.

State of Rhode Island, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of South Dakota, Department of Water and Natural Resources, Office of Air Quality and Solid Waste, Joe Foss Building, 523 East Capitol, Pierre, South Dakota 57501-3181.

State of Tennessee, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.

State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.

State of Washington, Department of Ecology, Olympia, Washington 98504.

State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

§ 75.5 Public availability of information

(a) The availability to the public of information provided to or otherwise obtained by the Administrator under this part shall be governed by Part 2 of this title.

§ 75.6 State authority

(a) The provisions of this part shall not be construed in any manner to preclude any State or political subdivision

thereof from adopting and enforcing any continuous monitoring requirement applicable to an affected source or unit, provided that such standard or limitation does not interfere with an affected facility's conformance with the requirements applicable to such unit or source prescribed under this part.

§ 75.7 Federal authority

(a) Under authority of Section 114 of the Act, the Administrator may,

(1) Secure information needed for the purpose of developing, revising, and implementing any standard under Section 412 or 821 of the Act and of determining whether any person is in violation of any such standard or requirement.

(2) Make inspections, conduct tests, examine records, and require the owner or operator of an affected unit to submit information reasonably required for the purpose of developing standards and methods or determining compliance with the provisions of this part.

§ 75.8 Prohibitions

(a) A violation of any regulation in this part by the owner or operator of an affected unit or his designated representative is a violation of the Act.

(b) No owner or operator of an affected unit or designated representative shall operate the affected unit

without complying with the requirements of §§ 75.11-75.23 and each Appendix of this part.

(c) No owner or operator of an affected unit or designated representative shall use any alternative monitoring system, alternative reference method, or substitute program for the continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with § 75.21.

(d) No owner or operator or designated representative shall emit or cause to be emitted any SO_2, NO_x, or CO_2, without accounting for all emissions in accordance with the provisions of §§ 75.11-75.23.

§ 75.9 Incorporation by reference

(a) The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the FEDERAL REGISTER on the date listed. These materials are incorporated as they exist on the date of approval, and a notice of any change in these materials will be published in the FEDERAL REGISTER. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, Room 8401, 1100 L Street, N.W., Washington, DC and at the Library (MD-35), U.S. EPA, Research Triangle Park, North Carolina.

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D4177-82, Standard Method for Automatic Sampling of Petroleum and Petroleum Products, IBR approved ___ for Appendix D of this part.

(2) ASTM D 4057-88, Standard Method for Manual Sampling of Petroleum and Petroleum Products, IBR approved ___ for Appendix D of this part.

(3) ASTM D129-64 (Reapproved 1978), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved ___ for Appendix D of this part.

(4) ASTM D1552-88, Standard Test Method for Sulfur in Petroleum Products (High Temperature Method), IBR approved _____ for Appendix D of this part.

(5) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, IBR approved _____ for Appendix D of this part.

(6) ASTM D4294-83, Standard Test Method for Sulfur in Petroleum Products by Non-Dispersive X-Ray Fluorescence Spectrometry, IBR approved _____ for Appendix D of this part.

(7) ASTM D941-88, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer, IBR approved _____ for Appendix D of this part.

(8) ASTM D1217-86, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, IBR approved ____ for Appendix D of this part.

(9) ASTM D1481-86, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, IBR approved ____ for Appendix D of this part.

(10) ASTM D1480-86, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, IBR approved ____ for Appendix D of this part.

(11) ASTM D1298-85, Standard Test Method for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, IBR approved ____ for Appendix D of this part.

(12) ASTM D4052-86, Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter, IBR approved ____ for Appendix D of this part.

(13) ASTM D1250-80 (Reapproved 1984), Standard Petroleum Measurement Tables, IBR approved _____ for Appendix D of this part.

(14) ASTM D240-87, Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved ____ for Appendices D and E of this part.

(15) ASTM D2382-88, Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved _____ for Appendices D and E of this part.

(16) ASTM D3178-89, Standard Method for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved _____ for Appendix E of this part.

(17) ASTM D3176-89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved _____ for Appendix E of this part.

(18) ASTM D1945-81, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved _____ for Appendix E of this part.

(19) ASTM D1946-90, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved _____ for Appendix E of this part.

(20) ASTM D2015-85, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved _____ for Appendix E of this part.

(21) ASTM D388-90, Standard Specification for Classification of Coals by Rank, incorporation by reference (IBR) approved _____ for Appendix E of this part.

(22) ASTM D1826-88, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved _____ for Appendix E of this part.

(23) ASTM D2502-87, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements, IBR approved _____ for Appendix E of this part.

(24) ASTM D2503-82 (Reapproved 1987), Standard Test Method for Molecular Weight of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved _____ for Appendix E of this part.

(25) ASTM D3238-85, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved _____ for Appendix E of this part.

(26) ASTM D2234-89, Standard Test Methods for Collection of a Gross Sample of Coal, IBR approved _____ for Appendix C of this part.

(27) ASTM D3177-89, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved _____ for Appendix C of this part.

Subpart B - Standards

§ 75.10 Applicability

(a) The provisions of this part apply to each existing affected unit subject to the Acid Rain Program, pursuant to the requirements of 40 CFR Part 72.

(b) The provisions of this part apply to each new utility unit upon commencement of commercial operation.

(c) The provisions of this part apply to each new unit and, except as provided by 40 CFR Part 74, to each existing utility unit or nonutility unit that opts into the Acid Rain Program.

§ 75.11 Monitoring of emissions and operations

(a) The owner or operator shall install, certify, operate, and maintain a continuous emission monitoring system on each affected unit, and record the output of the system, for measuring emissions of SO_2 (ppm) and NO_x (lb/mmBtu) and the volumetric flow (scfh) except as specified in this paragraph or elsewhere in this part. Each continuous emission monitoring system required by this part shall meet the installation, equipment, and performance specifications in Appendix A of this part.

(1) If the continuous emission monitoring system is installed such that any portion of the flue gases from an affected unit can by-pass the monitoring system, the owner or operator shall install, certify, operate, and maintain a

separate continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(2) Where two or more affected units or where affected units and nonaffected units utilize a common stack, the owner or operator shall comply with one of the following methods for monitoring SO_2 emissions (ppm) and volumetric flow (scfh).

(i) Where two or more affected units utilize a common stack, the owner or operator shall either:

(A) Combine allowances for compliance purposes according to the procedures in 40 CFR Part 73 and install, operate, and maintain a single continuous emission monitoring system, consisting of an SO_2 pollutant concentration monitor and a flow monitor meeting the requirements of Appendix A of this part (referred to hereafter as a "fully certified SO_2 continuous emission monitoring system"), for the combined effluent; or

(B) Monitor the emissions from each unit in the ducts to the common stack with fully certified SO_2 continuous emission monitoring systems.

(ii) Where Phase I affected units(s) and Phase II affected unit(s) utilize a common stack, the owner or operator shall designate the Phase II unit(s) as a substitution unit(s) pursuant to 40 CFR Part 72.41, and

comply with paragraph (a)(2)(i) of this section, except as provided in paragraph (a)(2)(v) of this section.

(iii) Where affected unit(s) and nonaffected unit(s) utilize a common stack, the owner or operator shall designate the nonaffected unit(s) as "opt-in" unit(s) and submit an opt-in plan in accordance with the provisions of 40 CFR Part 72.50 and 40 CFR Part 74, and comply with paragraph (a)(2)(i) of this section, except as provided in paragraph (a)(2)(v) of this section.

(iv) Where an affected Phase I unit and a new unit utilize a common stack, the owner or operator shall submit a permit application for the new unit in accordance with the requirements for Phase I affected units as specified in 40 CFR Part 72, and comply with paragraph (a)(2)(i) of this section, except as provided in paragraph (a)(2)(v) of this section.

(v) The requirements of paragraphs (a)(2)(ii), (a)(2)(iii), and (a)(2)(iv) of this section shall not apply where the owner or operator installs, operates, and maintains a fully certified SO_2 continuous emission monitoring system in the common stack for monitoring the combined effluent from the affected unit(s) and nonaffected unit(s) and employs one of the following methods to account for emissions from the affected unit(s).

(A) Monitors the emissions from the nonaffected unit(s) in the duct(s) to the common stack and calculates the emissions from the affected unit(s) as the difference between the emissions measured in the common stack and the emissions measured in the duct(s) from the nonaffected unit(s).

(B) Develops, demonstrates, and provides information and data to the Administrator on methods for apportioning the emissions measured in the common stack to individual affected unit(s) and to the nonaffected unit(s). The Administrator may approve such demonstrated substitute methods for apportioning emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(3) Where two or more affected units or where affected units and nonaffected units utilize a common stack, the owner or operator shall comply with one of the following methods for monitoring the NO_x emission rate (lb/mmBtu).

(i) Where two or more units utilize a common stack, and all units are not subject to any NO_x emission limitation under 40 CFR Part 76 or all units are subject to the same NO_x emission limitation, the owner or operator shall either:

(A) Install, operate, and maintain a single continuous emission monitoring system for NO_x emission rate, consisting

of a NO_x pollutant concentration monitor and a diluent gas monitor meeting the requirements of Appendix A of this part (referred to hereafter as a "fully certified NO_x continuous emission monitoring system") and, if appropriate, submit a NO_x emissions averaging plan for the units in accordance with 40 CFR 72 and 76; or

(B) Monitor the emissions from each unit in the ducts to the common stack with fully certified NO_x continuous emission monitoring systems.

(ii) Where two or more affected units utilize a common stack and the units are subject to different NO_x emission limitations under 40 CFR Part 76, the owner or operator shall either:

(A) Install, operate, and maintain a fully certified NO_x continuous emission monitoring system in the common stack and either comply with the most stringent NO_x emission limitation or submit a NO_x emissions averaging plan for the units in accordance with 40 CFR Parts 72 and 76; or

(B) Monitor the NO_x emission rate from each unit in the duct to the common stack with fully certified NO_x continuous emission monitoring systems and apportion total emissions to each unit by applying to the Administrator as described in paragraph (a)(2)(v)(B) above.

(iii) Where two or more affected units utilize a common stack, and one or more units is not subject to a NO_x

emission limitation and one or more units is subject to a NO_x emission limitation under 40 CFR Part 76, the owner or operator shall either:

(A) Monitor the NO_x emission rate from each unit in the ducts to the common stack with fully certified NO_x continuous emission monitoring systems and apportion total emissions to each unit with a NO_x emission limitation by applying to the Administrator as described in paragraph (a)(2)(v)(B) of this section; or

(B) Use the method specified in paragraph (a)(2)(v)(A) above to calculate the NO_x emission rate(s) for unit(s) with a NO_x emissions limitation and apportion total emissions to each such unit by applying to the Administrator as described in paragraph (a)(2)(v)(B) of this section.

(iv) Where affected unit(s) and nonaffected unit(s) utilize a common stack and one or more of the affected units is subject to a NO_x emission limitation under 40 CFR Part 76 the owner or operator shall either:

(A) Comply with the provisions specified in paragraph (a)(3)(iii) of this section; or

(B) Comply with the provisions specified in paragraph (a)(2)(iii) of this section and install, operate, and maintain a fully certified NO_x continuous emission monitoring system along with each fully certified SO_2 continuous emission monitoring system.

(b) Where the SO_2 pollutant concentration monitor measures emissions on a dry basis, the owner or operator shall install and operate a moisture monitor or continuously account for the moisture content of the gas.

(c) The owner or operator shall determine the total annual CO_2 emissions (tons) from each affected unit as required by this part.

(d) The owner or operator shall install, operate, and maintain a continuous monitoring system on each affected unit, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere as required by this part.

(e) Each continuous emission monitoring system and continuous opacity monitoring system required by this part shall be installed, certified, and operational on or before:

(1) November 15, 1993, for each Phase I affected unit.

(2) January 1, 1995, for each Phase II affected unit that has not already met the requirements of this part.

(3) The date on which a substitution unit becomes an affected unit in accordance with 40 CFR Part 74.

(4) The date on which a new unit commences commercial operation.

(f) All continuous monitoring systems shall be installed and operational prior to conducting initial certification tests under § 75.19. Verification of

operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the system or component.

(g) Prior to the operational date given in paragraph (e) of this section, all data acquisition and handling systems installed as a part of the continuous emission monitoring system shall be certified to produce valid calculations of the emissions in terms of the standard (e.g., lb/hr for SO_2 and lb/mmBtu for NO_x) from the data generated by the component analyzers in the continuous emission monitoring system.

(h) The owner or operator shall convert all emissions into units of the applicable allowance or emission limit by means of the data acquisition and handling system, using the conversion procedures in Appendix E of this part.

(i) Except for system breakdowns, repairs, and routine adjustments required under § 75.20, all continuous emission monitoring systems and continuous opacity monitoring systems required by this part shall be in operation at all times during the operation of the affected unit and shall meet the following requirements.

(1) Each continuous emission monitoring system and component thereof shall be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data

recording) for each successive 15-min interval. All SO_2 pollutant concentration, volumetric flow, and NO_x emission rate data shall be reduced to 1-hr averages. These averages shall be computed from four or more data points equally spaced over each 1-hr period, except for periods of calibration, quality assurance activities, maintenance or repair. During these periods, a valid hour shall consist of at least two data points with each representing a 15-min period and a cycle of operation as described above.

(2) All continuous opacity monitoring systems shall complete a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. All opacity data shall be reduced to 6-min averages calculated from 36 or more data points equally spaced over each 6-min period, except where a different averaging period is required and specified in the applicable State implementation plan or operating permit.

(j) Failure of the continuous emission monitoring system to acquire four valid data points, except for periods of calibration, quality assurance activities, maintenance or repair, shall result in the loss of such data for the entire hour and the owner or operator shall record and report data by means of the data acquisition and handling system for the

missing hour in accordance with the applicable procedures for obtaining missing data in §§ 75.12, 75.13, and 75.14.

(k) The owner or operator shall account for all heat input to each affected unit for every hour or part of an hour that fuel is combusted following the procedures in Appendix E of this part and shall record and report the heat input in accordance with §§ 75.22 and 75.23.

(l) An affected unit for which the designated representative and the owner or operator submit a certified commitment, as required in § 75.23(i), to retire such unit permanently prior to January 1, 1995, is exempt from the requirements of this part.

(m) Substitution units shall be subject to all the continuous emission monitoring requirements applicable to Phase I units.

§ 75.12 Monitoring of SO_2 emissions

(a) The owner or operator shall install, operate, and maintain an SO_2 pollutant concentration monitor and data acquisition and handling system for measuring and recording the concentration (in ppm) of SO_2 emissions discharged to the atmosphere on each affected unit except as provided in paragraphs (b) and (c) below and elsewhere in this part.

(b) *Gas-fired units.* The owner or operator of an affected gas-fired unit may install, operate, and maintain an SO_2 pollutant concentration monitor (with a flow monitor)

or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in Appendix D of this part.

(c) *Oil-fired units.* The owner or operator of an affected oil-fired unit may install, operate, and maintain an SO_2 pollutant concentration monitor (with a flow monitor) or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in Appendix D of this part.

(d) *Phase I qualifying technology.* The owner or operator of an affected unit for which a Phase I qualifying technology has been installed shall install, certify, operate, and maintain a continuous emission monitoring system for the measurement of SO_2 emissions at the inlet to the SO_2 emission controls in addition to a continuous emission monitoring system downstream of the SO_2 emission controls for the measurement of SO_2 emissions discharged to the atmosphere. Each of these continuous emission monitoring systems shall measure the SO_2 emissions rate (in lb/mmBtu) and shall consist of an SO_2 pollutant concentration monitor and a diluent gas monitor for measuring the O_2 or CO_2 concentration of the flue gas.

(1) The SO_2 pollutant concentration monitors and the diluent gas monitors at the inlet and downstream (outlet) of

the SO_2 emission controls shall meet all requirements specified in Appendices A and B of this part.

(2) The owner or operator shall demonstrate that the SO_2 emission controls are a Phase I qualifying technology achieving at least a 90 percent SO_2 emission removal efficiency according to the following procedures.

(i) No later than 90 days after the startup of the SO_2 emission controls and any other time required by 40 CFR Part 72, the owner or operator shall conduct a 30-day test for SO_2 emissions removal efficiency. The average SO_2 emissions removal efficiency during the 30-day test shall be calculated using the following equations.

$$\%R = 100\ [1.0 - (1.0 - \%R_f/100)(1.0 - \%R_g/100)] \quad \text{(Eq. 1)}$$

where

$\%R$ = Overall percentage SO_2 emissions removal efficiency.

$\%R_f$ = Percentage SO_2 emissions removal efficiency from fuel pretreatment, calculated from Equation 19-22 in Reference Method 19, 40 CFR Part 60, Appendix A.

$\%R_g$ = Percentage SO_2 removal efficiency of the emission controls calculated from Equation 2 below.

$$\%R_g = 100\ [1.0 - \frac{E_o}{E_i}] \quad \text{(Eq. 2)}$$

where

E_o = Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the emission controls during the startup test (or calendar year).

E_i = Average hourly SO_2 emission rate in lb/mmBtu, measured at the inlet to the emission controls during the startup test (or calendar year).

$$E_o = \frac{\sum_{j=1}^{n} E_{hoj}}{n} \qquad \text{(Eq. 3)}$$

where

E_{hoj} = Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the emission controls.

n = Total unit operating hours during which the SO_2 continuous emission monitoring system at the outlet of the emission controls collected quality-assured data.

$$E_i = \frac{\sum_{j=1}^{m} E_{hij}}{m} \qquad \text{(Eq. 4)}$$

where

E_{hij} = Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the inlet to the emission controls.

m = Total unit operating hours during which the SO_2 continuous emission monitoring system at the inlet to the emission controls collected quality-assured data.

(ii) Total operating hours for the purpose of computing the average SO_2 emissions removal efficiency during the 30-day test shall include all periods when fuel

is being combusted except for periods of startup, shutdown, and malfunction.

(iii) The owner or operator shall record and report the results of the initial 30-day test as specified in § 75.22(e) and § 75.23(e).

(iv) Compliance with the 90-percent SO_2 emissions removal efficiency requirement under this part is determined annually from the date of startup of the SO_2 emission controls through 1999, using the average inlet and average outlet SO_2 emission rates, (in lb/mmBtu) during the calendar year. Each annual average percent reduction shall be calculated using Equations 1 through 4 above. Total operating hours for the purpose of computing annual average SO_2 emissions removal efficiency shall include all periods when fuel is being combusted including periods of startup, shutdown, and malfunction. The owner or operator shall record and report quarterly and annual average SO_2 emissions removal efficiency as specified in § 75.22 and § 75.23.

(v) The owner or operator shall use all valid hourly SO_2 emissions data (lb/mmBtu) measured and recorded by the SO_2 continuous emission monitoring system to calculate the initial 30-day and annual average percent SO_2 emissions removal efficiency.

(A) Only quality-assured SO_2 emissions data measured by the inlet and outlet SO_2 pollutant concentration and

diluent gas monitors shall be used in the calculation of SO_2 emissions removal efficiency.

(B) The owner or operator shall use a minimum of 20 hours of data for each unit operating day during the startup test. A minimum of 600 hours of data is required during the startup test. If the number of hours of data during the startup test falls below the minimum requirement, the owner or operator shall repeat the test for an additional 30 days.

(e) ***Missing data procedures.*** For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of SO_2 pollutant concentration data (in ppm) has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent of data availability from the SO_2 pollutant concentration monitor for the previous 365 calendar days using the following equation.

$$\text{Percent annual monitor availability} = \frac{\text{Total unit operating hours for which monitor provided quality-assured data during previous 365 calendar days}}{\text{Total unit operating hours during previous 365 calendar days}} \times 100 \quad \text{(Eq. 5)}$$

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Except as provided in paragraph (e)(6) of this section, whenever data from the SO_2 pollutant concentration monitor have been available and recorded for 95.0 percent or more of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(ii) For a missing data period greater than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 30 days of operation as determined using the procedure in Section 4 of Appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(4) Except as provided in paragraph (e)(6) of this section, whenever data from the SO_2 pollutant concentration monitor have been available and recorded for at least 90.0 percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average of the hourly SO_2 concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(ii) For a missing data period of more than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 30 days of operation as determined using the procedure in Section 4 of Appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(iii) For a missing data period of more than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 365 days of operation as determined using the procedure in Section 4 of Appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(5) Whenever data from the SO_2 pollutant concentration monitor have been available and recorded less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute for each hour of each missing data period, the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 365 days of operation as determined using the procedure in Section 4 of Appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(6) When the affected unit is equipped with SO_2 emission controls and data from the SO_2 pollutant

concentration monitor have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 calendar days, the owner or operator may petition the Administrator to certify a parametric monitoring procedure, as described in Appendix C of this part, for calculating substitute data for missing data periods. The owner or operator shall use the procedures in paragraphs (d)(3) and (d)(4) of this section prior to receiving the Administrator's certification for a parametric monitoring procedure for filling in missing SO_2 pollutant concentration data.

(7) For an affected unit with SO_2 emission controls, where the data from the SO_2 pollutant concentration monitor have been available and recorded for less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data using the procedures in paragraph (d)(5) of this section.

(8) When the affected unit is equipped with SO_2 emission controls, the owner or operator shall provide information satisfactory to the Administrator as described in §§ 75.22 and 75.23 to verify the proper operation of the SO_2 emission controls for all periods of missing data. Whenever such data are not provided or proper operation of

the SO_2 emission controls has not been maintained, the uncontrolled emission rate shall apply.

§ 75.13 Monitoring of volumetric flow

(a) The owner or operator shall install, operate, and maintain a flow monitor and data acquisition and handling system for the continuous measurement and recording of the volumetric flow (in scfh) on each affected unit, except as provided in paragraphs (a)(1) and (2) below and in § 75.21.

(1) ***Gas-fired units.*** The owner or operator of an affected gas-fired unit may install, operate, and maintain a flow monitor (with an SO_2 pollutant concentration monitor) or provide other information satisfactory to the Administrator using the procedure for providing SO_2 emissions data in Appendix D of this part.

(2) ***Oil-fired units.*** The owner or operator of an affected oil-fired unit may install, operate, and maintain a flow monitor (with an SO_2 pollutant concentration monitor) or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in Appendix D of this part.

(3) Where no location exists in the existing ducts or stack that is greater than or equal to two stack or duct diameters downstream or one-half duct diameter upstream from a flow disturbance in accordance with the minimum siting criteria of Appendix A of this part, the owner or operator

may petition the Administrator for an alternative monitoring location or monitoring method. The owner or operator electing to petition the Administrator for an alternative monitoring method shall report the information and data as described in § 75.23.

(c) ***Moisture.*** The owner or operator of an affected unit equipped with an SO_2 pollutant concentration monitor that measures on a dry basis shall determine the moisture content of the flue gases continuously (or on an hourly basis) and correct the measured hourly flow rates for moisture when calculating the SO_2 emissions using the procedures in Appendix E of this part. The flow monitor shall meet all of the required specifications in Appendix A of this part after the correction for the moisture content of the flue gases.

(d) ***Missing data procedures.*** For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of flow data (in scfh) has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent annual monitor availability of the flow monitor over the previous 365 calendar days using Equation 5 in § 75.12(e).

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Whenever data from the flow monitor have been available and recorded for 95.0 percent or more of the total operating hours for the unit during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly flow rate recorded by the monitor during the previous 365 days at the corresponding unit load range recorded for the missing hour, as determined using the procedure in Section 3 of Appendix C of this part.

(ii) For a missing data period greater than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in Section 3 of Appendix C of this part; or

(B) Average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the

missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(4) Whenever data from the flow monitor have been available and recorded for at least 90.0 percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(ii) For a missing data period greater than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in Section 3 of Appendix C of this part; or

(B) Average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the load-based procedure in Section 3 of Appendix C of this part.

(iii) For a missing data period greater than 24 hours, substitute the 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(5) Whenever data from the flow monitor have been available and recorded for less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute the 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

§ 75.14 Monitoring of NO_x emissions

(a) The owner or operator shall install, operate and maintain a continuous emission monitoring system and data acquisition and handling system for measuring and recording NO_x emissions (in lb/mmBtu) discharged to the atmosphere on each affected unit except as provided in § 75.21. The

continuous emission monitoring system shall consist of a NO_x pollutant concentration monitor for measuring the concentration (in ppm) of NO_x emissions and a diluent gas monitor for measuring the O_2 or CO_2 content of the flue gases.

(b) Hourly, quarterly, and annual NO_x emission rates shall be calculated by combining the NO_x and diluent (O_2 or CO_2) concentration values in accordance with the procedures in Appendix E of this part.

(c) *Missing data procedures.* For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of NO_x emission rate data has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent annual availability of the NO_x continuous emission monitoring system over the previous 365 calendar days using Equation 5 in § 75.12(e).

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Except as provided in paragraph (c)(6) of this section, whenever data from the NO_x continuous emission monitoring system have been available and recorded for 95.0 percent or more of the total unit operating hours during the

previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly NO_x emission rate (in lb/mmBtu) recorded by the system days at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(ii) For a missing data period greater than 24 hours, substitute greater of the following values:

(A) 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in Section 3 of Appendix C of this part; or

(B) Average hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(4) Except as provided in paragraph (c)(6) of this section, whenever data from the NO_x continuous emission monitoring system have been available for at least 90.0

percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(ii) For a missing data period of greater than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(B) Average hourly NO_x emission rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(iii) For a missing data period greater than 24 hours, substitute the 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(5) Whenever data from the NO_x continuous emission monitoring system have been available less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute for each hour in each missing data period the 90th percentile hourly NO_x emission rate at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in Section 3 of Appendix C of this part.

(6) When the affected unit is equipped with post-combustion NO_x emission controls, and data from the NO_x continuous emission monitoring system have been available and recorded for 90.0 percent or more of the total operating hours during the previous 365 calendar days, the owner or operator may petition the Administrator to certify a parametric monitoring procedure, as described in Appendix C of this part, for calculating substitute data for missing data periods. The owner or operator shall use the procedures in paragraphs (c)(3) and (c)(4) of this section prior to receiving the Administrator's certification for a

parametric monitoring procedure for filling in missing NO_x emission rate data.

(7) When the affected unit is equipped with post-combustion NO_x emission controls, and data from the NO_x continuous emission monitoring system have been available for less than 90.0 percent of the total operating hours during the previous 365 calendar days, the owner or operator shall use the procedure in paragraph (c)(5) of this section for calculating substitute data for missing data periods.

(8) When the affected unit is equipped with post-combustion NO_x emission controls, the owner or operator shall provide information satisfactory to the Administrator as described in §§ 75.22 and 75.23 of this part to verify the proper operation of the NO_x removal system during all periods of missing data. Whenever such data are not provided or proper operation of the post-combustion NO_x emission controls has not been maintained, the uncontrolled emission rate shall apply.

§ 75.15 Monitoring of CO_2 emissions

(a) Except as provided in paragraph (b) of this section, each owner or operator shall monitor CO_2 emissions (in lb/day) discharged to the atmosphere from each affected unit using either of the following methods.

(1) Install, operate, and maintain a continuous emission monitoring system and a data acquisition and

handling system to measure and record the CO_2 emission rate (in lb/hr) using the procedures in Appendix E of this part. The continuous emission monitoring system shall consist of a CO_2 diluent gas monitor for measuring the concentration (in ppm) of CO_2 and a flow monitor for measuring the volumetric flow rate (in scfh) of the flue gas. Daily and annual CO_2 emissions shall be obtained by summing hourly emissions data.

(2) Calculate, using the methods and procedures specified in Appendix E of this part, combustion-related CO_2 mass emissions (in lb/day) based on the measured carbon content of the fuel and the amount of fuel combusted. Annual CO_2 emissions shall be obtained by summing daily CO_2 emission estimates.

(b) When the affected unit is equipped with a wet limestone flue gas desulfurization system, a fluidized-bed combustion unit with limestone as the sorbent material, or another system that generates CO_2 from input materials other than fuel, the owner or operator shall account for all CO_2 emissions generated by the system. The owner or operator may either install, operate, and maintain a CO_2 continuous emission monitoring system to measure the total hourly, daily, and annual emissions or calculate both the combustion-related and sorbent-related CO_2 emissions using the procedures in Appendix E of this part.

§ 75.16 Monitoring of opacity

(a) The owner or operator shall install, operate, and maintain a continuous opacity monitoring system on each affected unit, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except as provided in paragraphs (b) and (c) below. Each continuous opacity monitoring system shall meet the installation, equipment, and performance specifications in Performance Specification 1 in Appendix B of 40 CFR Part 60.

(b) *Gas-fired units.* The owner or operator of an affected gas-fired affected unit is exempt from the opacity monitoring requirements of this part.

(c) *Units with wet flue gas desulfurization systems.* The owner or operator of an affected unit equipped with a wet flue gas desulfurization system for SO_2 emissions control is exempt from the opacity monitoring requirements of this part.

§ 75.17 Reference methods for certification

(a) The owner or operator shall use the following methods to conduct monitoring system certification tests for certification or recertification of continuous emission monitoring systems and quality assurance and quality control procedures.

(1) Method 1 is the reference method for selection of sampling site and sample traverses.

(2) Method 2 is the reference method for determination of volumetric flow.

(3) Methods 3 or 3A are the reference methods for the determination of the dry molecular weight O_2 and CO_2 concentrations in the emissions.

(4) Method 4 is the reference method for the determination of moisture in the stack.

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7B, 7C, 7D or 7E, as applicable, are the reference methods for determining SO_2 and NO_x pollutant concentrations.

(b) Each of the methods identified in paragraph (a) of this section may be found in Appendix A of 40 CFR Part 60.

§ 75.18 Certification procedures

(a) Each continuous emission monitoring system shall be certified prior to use under Title IV of the Act. Recertification is required following any change in the continuous emission monitoring system that could adversely affect the ability of the system or procedure to measure or record the appropriate pollutant mass emission rate, volumetric flow, or concentration (e.g., change in gas cells, path lengths, probe, or system optics). Only output as recorded by the data acquisition and handling system shall be used for the comparison of monitor measurements to

the reference method values during certification or recertification.

(1) To obtain certification or recertification of a continuous emission monitoring system for pollutant concentration, emission rate, and/or volumetric flow, the owner or operator shall submit a formal request to the Administrator and shall provide a copy of the submission to the appropriate State air pollution control agency and the applicable Regional Administrator.

(2) The owner or operator shall include the reports and information specified in § 75.23(b) in each request for certification or recertification. A complete request for certification or recertification shall consist of all required information, including certification test results.

(3) Following review of the request and supporting documentation, the Administrator will issue a written notice of approval or disapproval to the owner or operator within 120 days of receipt of a complete request for certification or recertification.

(4) Any complete request for certification or recertification that meets the requirements of this part and for which a notice of approval is not issued within 120 days of receipt will be automatically certified for use under Title IV of the Act.

(5) The owner or operator of an affected unit for which certification or recertification is disapproved shall revise equipment, procedures, or methods as needed and resubmit a request for certification or recertification according to the procedures in this section.

(6) Whenever a request for certification or recertification of a monitor's operation is disapproved, the owner or operator shall use the uncontrolled emission rate to account for the affected unit's emissions until such time as the monitor can be adjusted, repaired, or replaced and certified.

(b) Any alternative monitoring system shall be approved and certified prior to use under Title IV of the Act. Recertification is required following any change in the system or procedure that could affect the ability of the system to measure or record emissions other than routine maintenance or corrective action. To obtain approval and certification of such an alternative monitoring system, the owner or operator shall submit a request for approval and certification or recertification to the Administrator. The Administrator will publish the request in the FEDERAL REGISTER and will issue a notice of approval or disapproval following a public comment period of 60 days.

(c) No alternative emissions monitoring system shall be authorized by a permitting authority in a permit issued

pursuant to 40 CFR Part 72 unless approved by the Administrator in accordance with this part.

§ 75.19 Certification tests

(a) Prior to the date by which the continuous emission monitoring system must be installed and operational, the owner or operator shall conduct certification tests to demonstrate that the continuous emission monitoring system and components meet the specifications in Appendix A of this part. The output from the data acquisition and handling system shall be used to compare the monitor or continuous emission monitoring system measurements to the reference method values during certification tests. As described in Appendix A, the following certification tests are to be performed.

(1) For each SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system (i.e., NO_x pollutant concentration monitor and diluent gas monitor), a calibration error test, a relative accuracy test, a bias test, and a cycle time/response time test.

(2) For each flow monitor, a relative accuracy test, a bias test, and a calibration error or electronic drift test, and for each differential pressure flow monitor, an orientation sensitivity test.

(3) For each CO_2 monitor used for continuously monitoring CO_2 emissions, a calibration error test, a relative accuracy test, and a bias test.

(4) For each combined SO_2/flow monitoring system, a relative accuracy test and a bias test (effective January 1, 2000).

(b) Prior to the date by which the continuous opacity monitoring system must be installed and operational, the owner or operator shall conduct certification tests to demonstrate that the continuous opacity monitoring system meets requirements of Performance Specification 1 in 40 CFR Part 60, Appendix B. As described in Performance Specification 1, the following tests are to be performed.

(1) Calibration error test.

(2) Response time test.

(3) Zero drift test.

(4) Calibration drift test.

(c) The owner or operator shall record and report the results of each certification test as required in §§ 75.22 and 75.23.

(d) A CO_2 monitor certified for use in an NO_x monitoring system shall be deemed to be certified for the purposes of § 75.15.

§ 75.20 Quality assurance and quality control procedures

(a) The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous emission monitoring system according to the quality assurance and quality control procedures in Appendix B of this part.

(b) If an out-of-control period occurs, the owner or operator shall take corrective action and repeat the applicable test as described in Appendix B of this part. During the period the monitor or continuous emission monitoring system is out of control, recorded data may not be used in data averages and calculations. The owner or operator shall apply the procedures for missing data until the monitor or monitoring system has successfully met the relevant criteria as demonstrated by a subsequent test.

(1) For calibration error or electronic drift tests, an out-of-control period occurs when the calibration error or electronic drift exceeds twice the applicable specification in Appendix A of this part (e.g., when the calibration error of a pollutant concentration monitor exceeds 5.0 percent, the calibration error of a diluent gas monitor exceeds 1.0 percent, or the calibration error or electronic drift of a flow monitor exceeds 6.0 percent).

(2) For relative accuracy, interference, and orientation sensitivity tests, an out-of-control period

occurs when the measured value exceeds the applicable specification in Appendix A of this part.

(c) The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous opacity monitoring system according to the quality assurance and quality control procedures in Method 203 in 40 CFR Part 52, Appendix M.

§ 75.21 Alternative monitoring systems

(a) The owner or operator of an affected unit required to install a continuous emission monitoring system may apply to the Administrator for approval of an alternative monitoring system (or system component) to determine average hourly emission data for SO_2, NO_x, and/or volumetric flow by demonstrating that the alternative monitoring system has the same or better precision, reliability, accessibility, and timeliness as that provided by the continuous emission monitoring system. The following requirements shall be met by the alternative monitoring system when compared to a contemporaneously operating, fully certified continuous emission monitoring system.

(1) To demonstrate precision equal to or better than the continuous emission monitoring system, the owner or operator shall conduct an F-test, a correlation analysis, and a t-test for bias as described in this section. The t-test shall be performed only on sample data at the normal

operating level whereas the F-test and the correlation analysis must be performed on each of the data sets required under paragraphs (a)(1)(iv) and (a)(1)(vi) of this section. The owner or operator shall collect and analyze data that meet the following requirements.

(i) Data from the alternative monitoring system and the continuous emission monitoring system are to be collected and paired in a manner that ensures each pair of values applies to hourly average emissions during the same hour.

(ii) An alternative monitoring system that directly measures emissions shall have probes or other measuring devices in locations that are in proximity to the continuous emission monitoring system and shall provide data on the same parameters as those measured by the continuous emission monitoring system. Data from the alternative monitoring system shall meet the statistical tests for precision in paragraph (b) of this section and the t-test for bias in Appendix A of this part.

(iii) An alternative monitoring system that indirectly quantifies emission values (e.g., by measuring inputs, operating characteristics, or outputs and then applying a regression or another quantitative technique to estimate emissions) shall meet the statistical tests for precision in

paragraph (b) of this section and the t-test for bias in Appendix A of this part.

(iv) For flow monitor alternatives, the alternative monitoring system shall provide sample data while the unit (or units, if more than one unit exhausts into the stack or duct) is burning primary fuel at the following gas flows: (1) the minimum safe and stable operating level, (2) 90 percent or greater of the maximum velocity, and (3) the normal operating level or an evenly spaced intermediary velocity if the normal operating level is within 10 percent of (1) or (2) above.

(v) For pollutant concentration monitor alternatives, the alternative monitoring system shall provide sample data for the normal fuel supply and for all alternative fuel supplies that have significantly different sulfur content.

(vi) For the normal unit operating level and normal fuel supply, paired hourly sample data must be provided for at least 90.0 percent of the hours during 30 successive unit operating days. For each of the remaining two operating levels (for flow monitor alternatives) and for each alternative fuel supply (for pollutant concentration monitor alternatives), paired hourly sample data must be provided for at least 24 successive unit operating hours.

(vii) The owner or operator shall not use missing data procedures to provide sample data.

(viii) If the collected data meet the requirements of the F-test, the correlation test, and the t-test at one or more, but not all, of the operating levels or fuel supplies, the owner or operator may elect to continue collecting the paired data for up to 60 additional days and repeat the statistical tests using the data for the entire 30- to 90-day period.

(ix) The owner or operator shall provide two separate time series data plots for the data at each operating level or fuel supply described in paragraphs (a)(1)(iv) and (a)(1)(v) of this section. Each graph shall have a horizontal axis that represents the clock hour and calendar date of the readings and shall contain a separate data point for every hour for the duration of the performance evaluation. The graphs shall show the following.

(A) Percentage difference versus time where the vertical axis represents the percentage difference between each paired hourly reading generated by the continuous emission monitoring system and the alternative emission monitoring system as calculated using the following equation.

$$\Delta e = \frac{e_p - e_v}{e_v} \times 100\% \qquad \text{(Eq. 6)}$$

where

Δe = Percentage difference between the readings generated by the alternative monitoring system and the continuous emission monitoring system.

e_p = Measured value from the alternative monitoring system.

e_v = Measured value from the continuous emission monitoring system.

(B) Alternative monitoring system readings and continuous emissions monitoring system readings versus time where the vertical axis represents hourly pollutant concentrations or volumetric flow, as appropriate, and two different symbols are used to represent the readings from the alternative monitoring system and the continuous emission monitoring system, respectively.

(2) To demonstrate reliability equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system is capable of providing valid 1-hr averages for 95.0 percent or more of unit operating hours over a 1-yr period and that the system meets the applicable requirements of Appendix B of this part.

(3) To demonstrate accessibility equal to or better than the continuous emission monitoring system, the owner or operator shall provide reports and onsite records of emission data to demonstrate that the alternative monitoring system provides data meeting the requirements of §§ 75.22 and 75.23.

(4) To demonstrate timeliness equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system can meet the requirements of §§ 75.22 and 75.23; can provide a continuous, quality-assured, permanent record of certified emissions data on an hourly basis; and can issue a record of data for the previous day within 24 hours.

(5) The owner or operator shall either demonstrate that daily tests equivalent to those specified in Appendix B of this part can be performed on the alternative monitoring system or demonstrate and document that such tests are unnecessary.

(6) The owner or operator shall demonstrate that all missing data can be accounted for in a manner consistent with the applicable procedures in §§ 75.12 - 75.14.

(b) *Statistical tests.* The owner or operator shall perform the F-test and correlation analysis as described below to demonstrate the precision of the alternative monitoring system.

(1) *F-test.* The F-test is conducted according to the following procedures.

(i) Calculate the variance of the certified continuous emission monitoring system or certified flow monitor as applicable, S_v^2, and the proposed method, S_p^2, using the following equation.

$$S^2 = \frac{\Sigma (e_i - e_m)2}{n-1} \qquad \text{(Eq. 7)}$$

where

e_i = Measured values of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method.

e_m = Mean of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method values.

n = Total number of paired samples.

(ii) Determine if the variance of the proposed method is significantly different from that of the certified continuous emission monitoring system or certified flow monitor, as applicable, by calculating the F-value using the following equation.

$$F = \frac{S_p^2}{S_v^2} \qquad \text{(Eq. 8)}$$

Compare the experimental F-value with the critical value of F at the 95-percent confidence level with n-1 degrees of freedom. The critical value is obtained from a table for F-distribution. If the calculated F-value is greater than the critical value, the proposed method is unacceptable.

(2) *Correlation analysis.* The correlation analysis is conducted according to the following procedures.

(i) Plot each of the paired emissions readings as a separate point on a graph where the vertical axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the alternative monitoring system and the horizontal axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the continuous emission monitoring system. On the graph, draw a horizontal line representing the mean value, $\bar{e}_p$, for the alternative monitoring system and a vertical line representing the mean value, $\bar{e}_v$, for the continuous emission monitoring system where,

$$\bar{e}_p = \frac{\Sigma\, e_p}{n} \qquad \text{(Eq. 9)}$$

and

$$\bar{e}_v = \frac{\Sigma\, e_v}{n} \qquad \text{(Eq. 10)}$$

where

e_p = Hourly value generated by the alternative monitoring system.

e_v = Hourly value generated by the continuous emission monitoring system.

n = Total number of hours for which data were generated for the tests.

A separate graph shall be produced for the data generated at each of the operating levels or fuel supplies described in paragraphs (a)(1)(iv) and (a)(1)(v).

(ii) Calculate the coefficient of correlation, r, between the emissions data from the alternative monitoring system and the continuous emission monitoring system using the following equation.

$$r = \frac{\Sigma e_p e_v - (\Sigma e_p)(\Sigma e_v)/n}{\{[\Sigma e_p^2 - (\Sigma e_p)^2/n][\Sigma e_v^2 - (\Sigma e_v)^2/n]\}^{1/2}} \quad \text{(Eq. 11)}$$

(iii) If the calculated r-value is less than 0.8, the proposed method is unacceptable.

(c) The owner or operator shall include the following information in the application for approval and certification or recertification of an alternative monitoring system.

(1) Source identification information.

(2) A description of the alternative monitoring system.

(3) A description, results of the statistical tests for precision and bias, and data plots.

(4) Results of monitor reliability analysis.

(5) Results of monitor accessibility analysis.

(6) Results of monitor timeliness analysis.

(7) A detailed description of the process used to collect data, including location and method of ensuring an accurate assessment of operating hourly conditions on a real-time basis.

(8) Results of tests and measurements (including the results of all reference method field test sheets, charts, laboratory analyses, example calculations, or other data as appropriate) necessary to substantiate that the alternative monitoring system is equivalent in performance to an appropriate, certified operating continuous emission monitoring system.

(d) The owner or operator shall develop and implement written operation, maintenance, and quality assurance procedures for the alternative monitoring system as required in Appendix B of this part.

(e) The owner or operator shall submit information as requested by the Administrator to amend the permit to include any alternative monitoring system approved by the Administrator pursuant to this section.

§ 75.22 Recordkeeping requirements

(a) The owner or operator shall record hourly, with the exception of the measured percent sulfur in the fuel, the following information on unit operating time, load, and sulfur content range of fuel combusted for each affected unit, including units utilizing a common stack and electing

to combine allowances and monitors. The owner or operator shall record every 6 hours the measured percent sulfur by weight in the fuel as-fired after the bunker (see Example Figure 1).

(1) The date and hour.

(2) Unit (boiler) operating time (hour or fraction of an hour recorded to nearest 15-min interval).

(3) Total heat input (mmBtu, rounded to four significant digits).

(4) Total integrated hourly gross unit load (rounded to nearest tenth of MWge).

(5) Operating load range (1-13) corresponding to total integrated gross load (see Appendix C of this part).

(6) Sulfur content range (1-25) corresponding to the percent sulfur in fuel (see Appendix C of this part).

(7) Percent sulfur by weight in fuel (rounded to nearest hundredth of a percent).

(b) The owner or operator shall record hourly the following information for SO_2 emissions, volumetric flow, moisture (if applicable), and NO_x emissions for each affected unit (see Example Figures 2 and 3).

(1) For SO_2 emissions,

(i) The date and hour.

(ii) Average hourly concentration (ppm).

(iii) Average hourly concentration adjusted for bias, if used (ppm).

(iv) For method of emissions determination, the owner or operator shall record one of the following codes to denote the source of the hourly emissions measurement or estimation method.

(A) 1 - Primary certified pollutant concentration monitor.

(B) 2 - Certified backup or portable pollutant concentration monitor.

(C) 3 - Approved alternative monitoring system.

(D) 4 - Reference Method (Method 6, 6A, 6B, or 6C).

(E) 5 - Average of the hourly concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(F) 6 - 90th percentile hourly concentration recorded by the monitor at the corresponding sulfur content range during the previous 30 days of operation.

(G) 7 - 90th percentile hourly concentration recorded by the monitor at the corresponding sulfur content range during the previous 365 days of operation.

(H) 8 - Emissions estimate from Agency preapproved parametric monitoring system or correlation method for units with SO_2 emission controls.

(I) 9 - Other data (specify method).

(v) Hourly mass emission rate (lb/hr) except as specified in paragraphs (b)(vi)(A), (B), and (C) below.

(vi) Hourly mass emission rate (lb/hr) adjusted for bias, if used, except as specified in paragraphs (b)(vi)(A), (B), and (C) below.

(A) For gas-fired or oil-fired units using the optional SO_2 emissions data protocol in Appendix D of this part, the owner or operator shall record the following information when the unit is combusting oil.

(*1*) Hourly flow of oil (gal/hr or lb/hr).

(*2*) Sulfur content of daily oil sample (rounded to nearest hundredth percent).

(*3*) Method of oil sampling (flow proportional, continuous drip, or manual).

(*4*) Hourly SO_2 mass emission rate (lb/hr).

(*5*) Average SO_2 mass emission rate (lb/hr) for each calendar quarter and year.

(*6*) Heat input from each shipment of natural gas, if any (mmBtu, rounded to four significant digits).

(B) For gas-fired units using the excepted method of daily manual oil sampling, the owner or operator shall record daily when the unit is combusting oil the highest sulfur content recorded from the most recent 30 daily oil samples.

(C) For units using alternative monitoring systems approved pursuant to § 75.21, the owner or operator shall record the hourly SO_2 mass emission rate (lb/hr) according to the approved procedures.

(2) For volumetric flow,

(i) The date and hour.

(ii) Average hourly volumetric flow (scfh).

(iii) Average hourly volumetric flow adjusted for bias, if used (scfh).

(iv) Average hourly stack moisture content, volume fraction, where SO_2 concentration measures are on a dry basis.

(v) For method of volumetric flow determination, the owner or operator shall record one of the following codes to denote the source of the hourly volumetric flow measurement or estimation method.

(A) 1 - Primary flow monitor.

(B) 2 - Backup flow monitor.

(C) 3 - Approved alternative monitoring system.

(D) 4 - Reference Method 2.

(E) 5 - Average hourly flow rate recorded by the monitor at the corresponding unit load range during the previous 30 days of operation.

(F) 6 - 90th percentile hourly flow rates recorded by the monitor at the corresponding unit load range during the previous 30 days of operation.

(G) 7 - 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range during the previous 365 days of operation.

(H) 8 - Other data (specify method).

(3) For NO_x emissions,

(i) The date and hour.

(ii) Average hourly concentration (ppm).

(iii) Average hourly emission rate (rounded to the nearest thousandth lb/mmBtu).

(iv) Average hourly emission rate adjusted for bias, if used (rounded to nearest thousandth lb/mmBtu).

(v) For method of emissions determination, the owner or operator shall record one of the following codes to denote the source of the hourly emission rate measurement or estimation method.

(A) 1 - Primary continuous emission monitoring system.

(B) 2 - Backup or portable continuous emission monitoring system.

(C) 3 - Approved alternative monitoring system.

(D) 4 - Reference Method (Method 7, 7A, 7B, 7C, 7D, or 7E).

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(E) 5 - Emissions estimate from Agency preapproved parametric monitoring system or correlation method for units with post-combustion NO_x emission controls.

(F) 6 - Average hourly emission rate recorded by the system at the corresponding unit load range during the previous 365 days of operation.

(G) 7 - 90th percentile hourly emission rate recorded by the system at the corresponding unit load range during the previous 30 days of operation.

(H) 8 - 90th percentile hourly emission rate recorded by the system at the corresponding unit load range during the previous 365 days of operation.

(I) 9 - Other data (specify method).

(c) The owner or operator of an affected unit with SO_2 emission controls shall record hourly the following information on the operation and effectiveness of the SO_2 emission controls during periods when data from the SO_2 pollutant concentration monitor or an approved alternative monitoring system are not available (see Example Figure 3).

(1) The date and hour.

(2) Number of scrubber modules in operation.

(3) Percent solids in slurry (rounded to nearest tenth of a percent).

(4) Feed rate of makeup slurry to each scrubber module (gal/min).

(5) For wet flue gas desulfurization (scrubber) controls,

(i) Inline measure of absorber pH.

(ii) Average pressure differential across each scrubber module (inches of water column).

(6) For dry flue gas desulfurization (scrubber) controls,

(i) Dew point approach temperature for each module (°F).

(ii) Average pressure differential across each scrubber module (inches of water column).

(7) Estimate of percent SO_2 emissions reduction.

(d) The owner or operator of an affected unit with post-combustion NO_x emission controls shall record hourly the following information on the operation and effectiveness of the NO_x emission controls during periods when data from the continuous emission monitoring system or an approved alternative monitoring system are not available.

(1) The date and hour.

(2) Inlet air flow rate to the unit (scfh).

(3) Excess oxygen concentration of flue gas at stack outlet (rounded to nearest tenth of a percent).

(4) Carbon monoxide concentration of flue gas at stack outlet (ppm).

(5) Temperature of the flue gas at outlet of the unit (°F).

(6) Other parameters of the post-combustion NO_x emission controls specific to the emission reduction process.

(e) The owner or operator of an affected unit with a Phase I qualifying technology shall also record the following information.

(1) The date and hour.

(2) Average hourly inlet SO_2 concentration (ppm).

(3) Average hourly inlet SO_2 emission rate (rounded to nearest thousandth lb/mmBtu).

(4) Average hourly outlet SO_2 emission rate (rounded to nearest thousandth lb/mmBtu).

(5) During the initial 30-day test, daily values of the percent SO_2 emissions removal by the controls, percent SO_2 emissions removal from fuel pretreatment (if applicable), and the percent total SO_2 emissions removal.

(6) From the date of startup of the SO_2 emission controls through the fourth quarter of 1999, average quarterly and, for the fourth quarter, average annual values of the percent SO_2 emissions removal by the controls, the percent SO_2 emissions removal from fuel pretreatment (if applicable), and the percent total SO_2 emissions removal.

(7) For units using fuel pretreatment to achieve the 90-percent removal efficiency, all data from fuel analysis and company records on weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(f) The owner or operator shall record the following information on a daily basis.

(1) For SO_2 pollutant concentration and diluent gas monitors and NO_x continuous emission monitoring systems,

(i) Percent monitor availability during the previous 365 calendar days (rounded to nearest hundredth of a percent).

(ii) Results of daily calibration error tests (percent error, rounded to nearest tenth of a percent) and number of out-of-control hours.

(iii) Bias adjustment factor for SO_2 pollutant concentration monitor (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(iv) Bias adjustment factor for NO_x continuous emission monitoring system (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(2) For flow monitors,

(i) Percent monitor availability during previous 365 calendar days (rounded to nearest hundredth of a percent).

(ii) Results of daily calibration error tests (percent error, rounded to nearest tenth of a percent) or electronic

drift tests (percent span drift, rounded to nearest tenth of a percent) and number of out-of-control hours.

(iii) Bias adjustment factor for flow monitor (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(3) Total daily calculated tons of SO_2 (rounded to nearest thousandth of a ton).

(4) F-factor value(s) used to convert NO_x pollutant concentration to emission rate in lb/mmBtu.

(5) Daily CO_2 mass emissions discharged to the atmosphere (lb).

(g) The owner or operator shall record hourly the average stack gas temperature (°F), the average gas exit velocity (rounded to nearest tenth fps), and the average diluent (O_2 or CO_2) concentration (rounded to nearest tenth of a percent) used to calculate NO_x emission rate in lb/mmBtu.

(h) The owner or operator shall maintain records on adjustments and maintenance performed on pollutant concentration and diluent gas monitors, flow monitors, opacity monitors, and moisture monitors (if applicable), including corrective actions.

(i) Each owner or operator shall maintain a file of all measurements, reports, and other information required by this part at the source in a form suitable for inspection

for at least 5 years. This file shall contain the following information and data.

(1) The information and data required in paragraphs (a)-(h) of this section.

(2) Records of all calibrations and recalibrations for the continuous emission monitoring system and the continuous opacity monitoring system.

(3) Records of all initial, quarterly, semiannual, and annual tests for the continuous emission monitoring system and records of all initial, quarterly, and annual tests required for the continuous opacity monitoring system.

(4) The results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate that all continuous emission monitoring systems and components meet the equipment and performance specifications in Appendix A of this part and that the continuous opacity monitoring system meets the requirements of Performance Specification 1 in 40 CFR Part 60, Appendix B.

(5) A copy of the quality control plan as described in Appendix B of this part.

(6) A copy of the source code (if available) used to process the continuous emission monitoring system or

component data and to calculate substitute data for missing data periods.

[Approved by OMB under control number _____]

§ 75.23 Reporting requirements

(a) *Monitoring plan.* Each designated representative of an affected unit shall submit Form ___, Monitoring Plan, including continuous emission monitoring system information, as part of the permit application required by 40 CFR Part 72. For Phase I affected units, the plan shall be submitted no later than the date of submission of the permit application. For Phase II affected units, the monitoring plan shall be submitted no later than the request for certification as required by § 75.18. The following information shall be reported using this form and if applicable, Supplementary Form ___ , Monitoring Plan for Common Stacks (see Figures 6 and 7).

(1) Acid Rain Program unit identification numbers(s), including the identification of all units utilizing a common stack and electing to combine allowances and monitors as provided for in § 75.11(a), the short name of each unit, and the name and address of the contact person for the continuous emission monitoring system.

(2) Description of monitor location, including scale diagrams and other documentation that the monitor location meets the appropriate siting criteria.

(3) Type of boiler or boilers for units utilizing a common stack and fuel(s) combusted.

(4) Type(s) of emission controls for SO_2, NO_x, and particulates installed or to be installed, including specifications of whether such controls are post-combustion, pre-combustion, or integral to the combustion process.

(5) Identification and description of all monitoring components in the continuous emission monitoring system (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor, if applicable; NO_x pollutant concentration monitor and diluent gas monitor) and the continuous opacity monitoring system, including:

(i) Manufacturer and model number.

(ii) Actual or projected installation date (month and year).

(iii) A brief description of the component type or method of operation (e.g., in situ pollutant concentration monitor or ultrasonic flow monitor).

(6) Identification and description of all major hardware and software components of the data acquisition and handling system, including:

(i) For hardware components, the manufacturer, model number, and actual or projected installation date.

(ii) For software components, identification of the provider, whether the software is customized or off-the-

shelf, a brief description of customized features, and availability of source code on-site.

(iii) A data flow diagram and a listing of computer algorithms used to calculate the recorded emissions and volumetric flow values.

(7) For gas-fired units and oil-fired units that intend to use the optional procedures in Appendix D of this part for monitoring SO_2 emissions, a description of the fuel flowmeter and data supporting its relative accuracy.

(b) *Certification tests.* The owner or operator of an affected unit shall provide notification and a report of the results of initial certification tests and any recertification tests as follows.

(1) The owner or operator shall provide notification to the Administrator of the dates upon which initial certification tests or recertification tests for the continuous emission monitoring system will be conducted. Notification shall be postmarked not less than 30 days prior to the test. For initial certification or recertification tests for the continuous opacity monitoring systems, notification shall be submitted to the applicable permitting authority. If notification substantially similar to that above is required by any other State or local agency, sending the Administrator a copy of that notification will

satisfy this notification requirement, provided the Acid Rain Program unit identification number(s) is denoted.

(2) The owner or operator shall furnish the Administrator (with copies to the applicable Regional Administrator and the applicable State air pollution control agency), a written report of the results of the performance tests for certification or recertification of the continuous emission monitoring system.

(3) The owner or operator shall submit the initial certification test results prior to the date the continuous emission monitoring system must be installed, operational, and certified.

(4) Each certification or recertification report shall include the following information.

(i) Name of utility and plant, address, contact person, and phone number.

(ii) Applicable plant and point identification numbers, unit number(s), identification of units sharing a common stack and electing to combine allowances and monitors as provided under § 75.11(a), and type of boiler and fuel(s) combusted.

(iii) Stack inside diameter (in feet) at the monitor location.

(iv) Stack height (in feet).

(v) A brief description of the continuous emission monitoring system installed to meet the requirements of this part, including the following information for each pollutant concentration, diluent gas, or flow monitor.

(A) Manufacturer.

(B) Serial number.

(C) Model number.

(D) Monitor type (e.g., in situ, extractive, dilution).

(E) Monitor location.

(vi) The results of each certification test for the continuous emission monitoring system in Appendix A of this part, including the type of test conducted and the date.

(vii) A brief description of the continuous opacity monitoring system installed to meet the requirements of this part.

(viii) The results of each certification test for the continuous opacity monitoring system required by § 75.19 and described in Performance Specification 1 of 40 CFR Part 60, Appendix B, including the type of test conducted and the date.

(ix) Verification of the accuracy of emissions and volumetric flow calculations performed by the data acquisition and handling system, including a summary of equations used to convert component data to units of the

standard and to calculate substitute data for missing data periods, including sample calculations.

(c) *Quarterly reports.* The designated representative shall electronically report the following data and information to the Administrator quarterly, beginning with the quarter during which the continuous emission monitoring system is initially certified. Each electronic report must be received at the address given in § 75.4(a) by the 30th day of the month following the end of each calendar quarter.

(1) The information and data required in paragraphs (a)-(f) of § 75.22.

(2) Tons of SO_2 emitted during the quarter and cumulative SO_2 emissions for calendar year.

(3) Average NO_x emission rate (lb/mmBtu) during the quarter and cumulative NO_x emission rate for calendar year.

(4) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(5) Total heat input (mmBtu) and integrated gross unit load (MWge) for quarter and cumulative heat input and integrated gross unit load for calendar year.

(d) *Electronic report format.* Each quarterly report shall be submitted electronically to the Administrator as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or by a modem.

(e) *Quality assurance and quality control test reports.* The owner or operator shall report, on a quarterly basis, the results of quarterly, semiannual, and annual quality assurance and quality control tests for the continuous emission monitoring system and the continuous opacity monitoring system required by Appendix B of this part, beginning with the quarter following initial certification of either system.

(1) Each report shall contain, at a minimum, information on the type(s) of tests conducted, the date, individual test run data on supporting data sheets, and the results of any bias test indicating low bias in the monitoring system or component and the bias adjustment factor from Equation 7-6 in Appendix A of this part. The owner or operator also shall report the results of all relative accuracy test audits performed during the quarter including those performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits and/or eliminating or reducing a bias adjustment factor.

(2) Each report must be received at the address given in § 74.4(a) by the 30th day of the month following the end of each calendar quarter. Quality assurance and quality control test run data and statistics must be reported electronically to the Administrator as an ASCII flat file

via either an IBM-compatible personal computer floppy diskette or by a modem. Test reports, supporting calculations, and explanatory material may be submitted in hard copy form.

(f) ***Phase I qualifying technology reports.*** The designated representative of an affected unit equipped with a Phase I qualifying technology should electronically report the information and data required in paragraphs (e)(1)-(5) of § 75.22 for the initial 30-day test to the Administrator by the 30th day of the month following the end of the test. The designated representative shall also electronically report the information and data required in paragraphs (e)(1)-(4) and (6) of § 75.22 to the Administrator on a quarterly basis, beginning with the startup of the SO_2 emission controls through the fourth quarter of 1999. Each report shall also contain all measurements and calculations necessary to substantiate that the qualifying technology achieves the required percent reduction in SO_2 emissions.

(g) ***Opacity reports.*** The owner or operator shall report excess emissions of opacity to the applicable permitting authority.

(h) ***Alternative flow monitor location demonstration reports.*** In cases where no location exists in the existing ducts or stack that will satisfy the siting criteria specified in § 75.13(a)(3) and in Appendix A of this part,

the owner or operator may petition the Administrator for an alternative monitoring location or alternative method for monitoring flow. The demonstration report must be received, for Phase I affected units, no later than prior to the date of submission of the permit application and, for Phase II affected units, no later than the request for certification as required by § 75.18. The demonstration report shall, at a minimum, contain the following information.

(1) Identification of the affected unit(s).

(2) Description of why the minimum siting criteria cannot be met within the existing ductwork or stack(s). This description shall include diagrams of the existing ductwork and stack(s) as well as documentation of any attempts to locate a flow monitor.

(3) Description of proposed alternative monitoring location or alternative method for monitoring flow.

(i) *Retiring units.* The owner or operator shall submit a statement, certified by the owner or operator and the designated representative, of the commitment to permanently retire an affected unit prior to January 1, 1995.

(1) The owner or operator shall certify the limited life of the unit prior to the date by which the continuous emission monitoring system must be installed.

(2) In no case may the notification be submitted after December 31, 1994.

(Approved by OMB under control number _____)

§ 75.24 [Reserved]

FIGURE 1
EXAMPLE DAILY UNIT OPERATING DATA

HOURLY OPERATING DATA						
Hour	Unit Operating Time hr	Total Heat Input mmBtu	Integrated Gross Unit Load MWge	Operating Load Range[1]	Fuel Sulfur Content %[2]	Sulfur Content Range[3]
01 02 03 04 . . 24					Record for each 6-hr period	
Total						

1 Use codes for Operating Load Range in Appendix C, Section 3.
2 Record on a six-hour basis. Denote beginning and ending hours of each six-hour period.
3 Use codes for Sulfur Content Range in Appendix C, Section 4.

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FIGURE 2
EXAMPLE DAILY SO_2 EMISSIONS AND FLOW RECORD

DAILY MONITOR OPERATION DATA

Date	SO_2 Monitor					Flow Monitor				
	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[1]	Bias Adjustment Factor	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[2]	Bias Adjustment Factor
		Low	High				Low	High		

HOURLY SO_2 EMISSIONS AND FLOW DATA

Hour	Average SO_2 Concentration		Method of Emissions Determination[3]	Measured Average Flow Rate scfh	Adjusted Average Flow Rate scfh	Average Stack Moisture %, by vol	Method of Flow Rate Determination[4]	SO_2 Emissions Rate	
	Measured ppm	Adjusted ppm						Measured lb/hr	Adjusted lb/hr
01									
02									
03									
.									
.									
24									
Total									

1 If daily calibration error is greater than 5%, SO_2 monitor is deemed to be out-of-control.

2 If daily calibration error is greater than 6%, flow monitor is deemed to be out-of-control.

3 Codes for Method of SO_2 Concentration Determination:

1 - Primary monitor
2 - Backup/portable monitor
3 - Alternative monitoring system
4 - Method 6, 6A, 6B or 6C
5 - Average hour before and after
6 - 90th percentile hourly concentration 30 days
7 - 90th percentile hourly concentration 365 days
8 - Preapproved parametric monitoring or correlation method
9 - Other (attach description)

4 Codes for Method of Flow Rate Determination:

1 - Primary monitor
2 - Backup/portable monitor
3 - Alternative monitoring system
4 - Method 2
5 - Average hourly flow rate 30 days
6 - 90th percentile hourly flow rate 30 days
7 - 90th percentile hourly flow rate 365 days
8 - Other (attach description)

FIGURE 3
EXAMPLE DAILY NO_x AND CO_2 EMISSIONS RECORDS

DAILY MONITOR OPERATION DATA												
	NO_x Monitoring System							CO_2 Monitor (if used)				
Date	% System Availability	NO_x % Calibration Error		Diluent % Calibration Error		Total Hours Out-of-Control[1]	Bias Adjustment Factor	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[2]	Bias Adjustment Factor

HOURLY NO_x EMISSIONS AND DAILY CO_2 EMISSIONS DATA					
	Average NO_x Emissions				
Hour	ppm	Measured Rate lb/mmBtu	Adjusted Rate lb/mmBtu	Method of Emissions Rate Determination[2]	Daily CO_2 Emissions lb
01					
02					
03					
.					
.					
.					
24					
Total					

1072 681

[1] If daily calibration error is greater than 5%, the monitor is deemed to be out-of-control.

[2] Codes for Method of NO_x Emissions Rate Determination:

1 - Primary monitoring system
2 - Backup/portable monitoring system
3 - Alternative monitoring system
4 - Method 7, 7A, 7B, 7C, 7D or 7E
5 - Preapproved parametric monitoring or correlation method
6 - Average hourly rate (lb/mmBtu) 365 days
7 - 90th percentile hourly rate 30 days
8 - 90th percentile hourly rate 365 days
9 - Other (attach description)

FIGURE 4
SUPPLEMENTARY SO_2 EMISSION CONTROL OPERATION INFORMATION FOR MISSING DATA PERIODS[1]

HOURLY CONTROL EQUIPMENT OPERATION DATA								
		All Scrubbers					Wet FGD	Dry FGD
Date	Hour	Number of Scrubber Modules in Operation	Average Slurry % Solids	Slurry Feed Rate gal/min	Average Pressure Differential in/wc[2]	Estimated % SO_2 Removal Efficiency	Average Inline Absorber pH	Dew Point Approach Temperature °F
To Be Completed Only for Hours for Which a Substitute SO_2 Emission Data Determination Method (Codes 4-9) Is Used								

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1 Information to be submitted by units equipped with SO_2 emission controls for each hour during which SO_2 emission determinations are not available from primary, back-up, or approved alternative monitoring systems.

2 Inches of water column.

FIGURE 5
SUPPLEMENTARY NO_x EMISSION CONTROL OPERATION INFORMATION FOR MISSING DATA PERIODS[1]

HOURLY CONTROL EQUIPMENT OPERATION DATA						
Date	Hour	Inlet Air Flow Rate scfh	Excess Oxygen %	CO Concentration Stack Outlet ppm	Outlet Flue Gas Temperature °F	Other Parameter[2]
To Be Completed Only for Hours for Which a Substitute NO_x Emission Data Determination Method (Codes 4-9) Is Used						

1 Information to be submitted by units equipped with post-combustion NO_x emission controls for each hour during which NO_x emission determinations are not available from primary, back-up, or approved alternative monitoring systems.

2 Parameters specific to post-combustion NO_x emissions reduction process. Specify other parameters reported.

1074 683

FIGURE 6

DRAFT 7510

Date 10/25/91

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Monitoring Plan

Follow "7510" Instruction packet in completing this form. Note: Phase I units must submit monitoring plan no later than the date of submission of the permit application; Phase II units must submit monitoring plan no later than the request for monitoring certification. Submit a revised copy of this form if any of the information that you report below changes.

I. UNIT IDENTIFICATION

A. Unit Information

1. Unit ARP ID Number

2. Short Name

B. Facility Information

1. Source or Facility Name

2. Street or P.O. Box

3. City

4. State

5. Zip

C. Contact for Monitoring Information

1. Contact Name

2. Phone *(area code & number)*

II. BOILER INFORMATION

A. Identify this unit's boiler type(s):

☐ 1. Tangentially fired ☐ 2. Dry bottom wall-fired ☐ 3. Wet bottom wall-fired ☐ 4. Cyclone ☐ 5. Applying cell burner technology

☐ 6. Other:

B. Date of initial boiler operation *(mm/dd/yy):* →

C. Estimated annual operation *(hours):* →

III. FUEL INFORMATION

Fuel	Estimated Annual % of Use *(Btu)*	Estimated Sulfur of Fuel *(lbs/mmBtu)*	Fuel	Estimated Annual % of Use *(Btu)*
A. Coal			D. Wood	
B. Oil			E. Refuse	
C. Natural Gas			F. Other	

IV. CONTROL EQUIPMENT

A. SO_2

☐ 1. Uncontrolled ☐ 2. Dry Lime FGD ☐ 3. Wet Limestone FGD

☐ 4. Other:

B. NO_x

☐ 1. Uncontrolled ☐ 2. Low NO_x Burner Technology

☐ 3. Other: ☐ a. Combustion ☐ b. Post Combustion

(Describe):

C. Particulates

☐ 1. Uncontrolled ☐ 2. Baghouse(s) ☐ 3. ESP

☐ 4. Other:

V. STACK INFORMATION

A. Inside Stack Diameter at Monitor Location → B. Height →

1075684

FIGURE 6

Please print or type in the unshaded areas only.

ARP Unit ID Number

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VI. COMMON STACK ELECTION

A. Does this unit share a common stack with other units?

☐ No. If no, complete sections VII - XI ☐ Yes. If yes, submit form 7512 and see VI.B.

B. If this unit is the Primary Unit for the stack, identify Primary ARP Unit ⟶ | C. Primary Unit ARP ID No. [from form 7512] | D. Short Name

E. Number of Units Sharing Monitor *(to be completed only for combined stacks):*

Monitor Type	Number of Units	Monitor Type	Number of Units	Monitor Type	Number of Units
1. SO_2 Outlet		3. Volumetric Flow		5. Diluent	
2. NO_x		4. Moisture		6. Opacity	

VII. SO_2 INLET MONITORING EQUIPMENT (if required)

A. Pollutant

1. Manufacturer: | 2. Model #:

3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. Dilution ☐ d. Other | 4. Installation Date *(mm/yy)*:

5. Type Description:

6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

B. Diluent

1. Manufacturer: | 2. Model #:

3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. O_2 ☐ d. CO_2 ☐ e. Other | 4. Installation Date *(mm/yy)*:

5. Type Description:

6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

VIII. SO_2 OUTLET MONITORING EQUIPMENT

A. Pollutant

1. Manufacturer: | 2. Model #:

3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. Dilution ☐ d. Other | 4. Installation Date *(mm/yy)*:

5. Type Description:

6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

B. Volumetric Flow

1. Manufacturer: | 2. Model #:

3. Type: ☐ a. Differential Pressure ☐ b. Ultrasonic ☐ c. Thermal ☐ d. Other | 4. Installation Date *(mm/yy)*:

5. Type Description:

6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

NOTE: SECTION VIII SO_2 OUTLET MONITORING EQUIPMENT is continued on Page 3 of this form ⟶

FIGURE 6

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VIII. SO_2 OUTLET MONITORING EQUIPMENT (cont.)

C. Moisture (if applicable)

1. Manufacturer:		2. Model #:	
		3. Installation Date *(mm/yy)*:	
4. Backup System:			

☐ 5. Approved Alternate in Use ☐ 6. Siting Information Attached

IX. NO_x MONITORING EQUIPMENT

A. Pollutant

1. Manufacturer:		2. Model #:	
3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. Other		4. Installation Date *(mm/yy)*:	
5. Type Description:			
6. Backup System:			

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

B. Diluent

1. Manufacturer:		2. Model #:	
3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. O_2 ☐ d. CO_2 ☐ e. Other		4. Installation Date *(mm/yy)*:	
5. Type Description:			
6. Backup System:			

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* ⟶

X. OPACITY MONITORING EQUIPMENT

1. Manufacturer:		2. Model #:	
		3. Installation Date *(mm/yy)*:	
4. Backup System:			

☐ 5. Approved Alternate in Use ☐ 6. Siting Information Attached

☐ 7. This unit submits excess emissions reports to:

(Name of State or Local Agency)

XI. DATA ACQUISITION SYSTEM

A. Hardware Components

☐ Additional Information Attached

Item	Manufacturer	Model #	Actual or Projected Installation Date *(mm/dd/yy)*
1			
2			
3			
4			
5			

NOTE: SECTION XI DATA ACQUISITION SYSTEM is continued on Page 4 of this form ⟶

FIGURE 5

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

XI. DATA ACQUISITION SYSTEM (cont.)

B. Software Components

☐ Additional Information Attached

Item	Provider	Customized?	Description
1			
2			
3			
4			
5			

☐ Data Flow Diagram and Equations Attached

C. Backup Plan - Systems

D. Backup Plan - Procedures

E. Primary DAS Contact

1. Contact Name	2. Phone *(area code & number)*
	- -

XII. CERTIFICATION

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of EPA Approved Designated Representative	B. DR ID Number

C. Signature	D. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

DRAFT 7512

Date 10/25/91

Please print or type in the unshaded areas only.

ARP Facility ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Monitoring Plan -- Common Stack Information

Follow "7512" Instruction packet in completing this form.

I. FACILITY IDENTIFICATION

Source or Facility Name

II. UNIT IDENTIFICATIONS

Identify the primary unit at A.1.

	A. Unit ARP ID Number	B. Short Name	C. Classification				
			Phase I	Phase II	New	Opt-In	Non-Affected
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

☐ Schematic diagram attached.

III. SO_2 EMISSIONS

UNIT	Single Combined Stack Monitor Combined Allowances		Separate Duct Monitoring for Each Unit	Emissions from Common Stack Monitor Apportioned by Approved Alternative Method	Common Stack Monitor Emissions Minus Emissions from Monitored Non-affected Unit	Emissions Data from this Unit to be Subtracted from Common Stack Monitor Emissions
	Yes	Allowance				
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
Total Allowance →						

1079 6 88

Please print or type in the unshaded areas only.

ARP Facility ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

IV. NO_x EMISSIONS

UNIT	NO_x Standard	Common Stack Monitor: Same Standard Applied for all Units	Common Stack Monitor: Most Stringent Standard Applied	Common Stack Monitor: Nitrogen Oxides Averaging Plan	Common Stack Monitor: Approved Alternative Method to Apportion Emissions	Common Stack Monitor: Will Subtract Emissions from Monitored Non-affected Unit	Common Stack Monitor: Emissions Data from this Unit to be Subtracted from Common Stack Monitor Emissions	Separate NO_x Monitor for Unit in Ducts
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								

V. CERTIFICATION

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of EPA Approved Designated Representative	B. DR ID Number

C. Signature	D. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments: _____

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APPENDIX A - SPECIFICATIONS AND TEST PROCEDURES

1. SO_2 Pollutant Concentration Monitors and NO_x Continuous Emission Monitoring Systems

1.1 Installation and Measurement Location. Following the procedures in Section 3.1, 40 CFR Part 60, Appendix B, Performance Specification 2, install the monitor or monitoring system at an accessible location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) such that the SO_2 pollutant concentration monitor or NO_x continuous emission monitoring system (NO_x pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see Section 6). If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, the monitor probe(s) must be relocated.

1.1.2 ***Point Pollutant Concentration or Diluent Gas Monitors.*** The measurement point shall be (1) within or centrally located within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.3 ***Path Pollutant Concentration or Diluent Gas Monitors.*** The measurement path shall (1) be totally within the inner area bounded by a line 1.0 meter from the stack or duct wall or (2) have at least 70.0 percent of the path

within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) be centrally located within any part of the centroidal area.

1.2 Equipment Specifications. Each pollutant concentration or diluent gas monitor shall be designed and equipped with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. The parts of the measurement system that shall be included, as applicable, are sample lines, filters, scrubbers, conditioners, data recorder, as much of the probe as practicable, and all other monitor components exposed to the sample gas during normal sampling. If the pollutant concentration monitor is an extractive type, the injection port shall be at a point no closer to the analyzer than the back of the probe. If dilution-type systems are used, the injection port shall be placed prior to any dilution. Daily calibration error checks shall be made by charging the pollutant concentration or diluent gas monitor with calibration gases through this injection port.

Each pollutant concentration or diluent gas monitor shall be designed to allow daily determinations of calibration error (positive or negative) at the low-level and high-level concentrations specified in Section 2.1, Appendix B, of this part.

1.2.1 ***Instrument Span.*** Select spans for pollutant concentration and diluent gas monitors so that they include

all expected emission rates and concentrations. The average concentration shall be between 40.0 and 75.0 percent of span. Whenever the monthly average concentration of the emissions being monitored falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the emission measurements fall within the cited boundaries. Full-scale exceedances shall not occur. Use dual-range analyzers to accommodate a wide range of expected concentrations.

1.3 Performance Specifications

1.3.1 ***Calibration Error.*** The calibration error of pollutant concentration monitors shall not deviate from the reference value of the calibration gas by more than 2.5 percent. This specification does not apply when the average concentration is 250 ppm or less. When the average concentration is equal to or less than 250 ppm, the calibration error shall not deviate from the reference value of the calibration gas cylinder by more than 5.0 percent or 8 ppm, whichever is greater.

The calibration error of diluent gas monitors shall not deviate from the reference value of the calibration gas by more than 0.5 percent. If the continuous emission monitoring system includes pollutant concentration and diluent gas monitors, calibration errors shall be determined separately for the pollutant concentration monitor and the diluent gas monitor.

1.3.2 *Relative Accuracy for SO_2.* The relative accuracy for SO_2 pollutant concentration monitors shall not exceed 10.0 percent. This specification does not apply to affected units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm. For these affected units, the mean value of the monitor measurements shall be within ±15.0 ppm of the reference method mean value.

1.3.3 *Relative Accuracy for NO_x.* The relative accuracy for NO_x continuous emission monitoring systems shall not exceed 10.0 percent. This specification does not apply to affected units where the average of the monitoring system measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.50 lb/mmBtu. For these affected units, the mean value of the NO_x continuous emission monitoring system measurements shall be within ±0.05 lb/mmBtu of the reference method mean value.

1.3.4 *Relative Accuracy for Diluent.* The relative accuracy for diluent gas monitors shall not exceed 10.0 percent of the reference method mean value or 1.0 percent O_2 or CO_2, whichever is greater.

1.3.5 *Bias.* SO_2 pollutant concentration monitors and NO_x continuous emission monitoring systems shall not exhibit low bias as determined by the test procedure in Section 7.5. The bias specification applies to all SO_2 pollutant concentration monitors, including those where the average

SO_2 concentration is 250.0 ppm or less, and to all NO_x continuous emission monitoring systems, including those where the average emission rate is 0.50 lb/mmBtu or less.

1.3.6 *Cycle Time/Response Time.* The cycle time/response time for pollutant concentration monitors, diluent gas monitors, and NO_x continuous emission monitoring systems shall not exceed 15 min.

2. Flow Monitors

2.1 Installation and Measurement Location. Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. For volumetric flow measurements where cyclonic or swirling flow conditions exist, use the procedures in Section 2.4 of Method 1 to establish a proper location for the flow monitor. Where the moisture content of the flue gas effects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of 40 CFR Part 60, Appendix A, to establish a proper location for the flow monitor. Flow monitor locations should be selected to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

The installation of a flow monitor is acceptable if the location satisfies the minimum siting criteria of Method 1 in 40 CFR 60, Appendix A (i.e., the location is greater than or equal to two stack or duct diameters downstream or one-half diameter upstream from a flow disturbance), and the flow monitor satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the Administrator may certify the location as acceptable. Whenever it is physically impossible to install a flow monitor at any location that satisfies these physical siting criteria in either the stack or breeching ducts serving any unit or combination of units, the owner or operator may petition the Administrator for an alternative monitoring location or alternative method for monitoring flow.

Whenever the flow monitor is installed in a location that is greater than or equal to two stack or duct diameters downstream or one-half diameter upstream from a flow disturbance, but nevertheless the monitor does not achieve the performance specifications of this part, the owner or operator shall utilize the alternative procedures described in Section 2.5 of Method 1 to make accurate flow rate determinations. Whenever the owner or operator successfully demonstrates that such modifications are necessary, the

Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

2.2 Equipment Specifications. All flow monitor designs shall provide for at least quarterly transducer checks. Flow monitor designs shall meet the applicable performance specifications in Section 2.3. All flow monitors shall either be designed for daily multipoint calibration or the owner or operator must perform quarterly relative accuracy test audits as specified in Appendix B of this part. If the flow monitor is designed for daily calibration, the monitor shall be equipped with a calibration system that allows a check once every 24 hours (or more frequently) of the entire measurement system from the probe tip through the data acquisition and handling system at two gas flows: (1) the normal operating rate, and (2) 90 percent of more of the maximum operating rate.

2.2.1 ***Instrument Span.*** Select the span of the flow monitor such that it includes all expected volumetric flow rates. The average volumetric flow shall be between 40.0 and 75.0 percent of span. Whenever the monthly average volumetric flow falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the monthly average volumetric flow is within the cited ranges.

2.2.2 ***Interference Checks.*** Ultrasonic and differential pressure flow monitors shall provide an

automatic timed periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the transceiver surface/sample port, and the probe and lines, respectively, free of obstructions. Self-averaging differential pressure flow monitors shall provide an automatic drain for wet gases. All flow monitors shall provide a method or mechanism (manual check is acceptable) for zeroing and calibrating the transducer. Differential pressure flow monitors shall provide a method or mechanism for detecting leaks or pluggage in the system. Thermal flow monitors shall provide a method or mechanism for ensuring the probe remains clean.

2.3 Performance Specifications

2.3.1 ***Calibration Error.*** The calibration error of flow monitors that perform daily calibration error tests shall not deviate from the reference value by more than 3.0 percent.

2.3.2 ***Electronic Drift.*** The electronic drift of flow monitors that do not perform daily calibration error tests shall not deviate from the reference value of the input signal by more than 3.0 percent.

2.3.3 ***Relative Accuracy.*** The relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 15.0 percent through December 31, 1999. Beginning on January 1, 2000, the relative accuracy of flow monitors on both Phase I and Phase II affected units

shall not exceed 10.0 percent. These specifications do not apply to affected units where the average of the flow monitor measurements of gas velocity during the relative accuracy test audit is less than or equal to 10.0 feet per second (fps). For these affected units, the mean value of the flow monitor measurements shall be within ±1.0 fps of the reference method mean value.

2.3.4 ***Bias.*** Flow monitors shall not exhibit low bias as determined by the test procedure in Section 7.5. The bias specification applies to all flow monitors including those where the average gas velocity is 10.0 fps or less.

2.3.5 ***Orientation Sensitivity.*** For velocity measurement systems that use the flow direction of the gas, such as differential pressure flow monitors, no measurement shall exceed ±4.0 percent of the zero-degree orientation value.

3. Combined SO_2-Flow Monitoring Systems

3.1 Relative Accuracy. Beginning on January 1, 2000, the relative accuracy for combined SO_2-flow monitoring systems for determining SO_2 emissions in lb/hr shall not exceed 10.0 percent. This specification applies to both Phase I and Phase II affected units, except those units where the average SO_2 concentration is less than or equal to 250.0 ppm or the average gas velocity is less than or equal to 10.0 fps during the relative accuracy test audit.

3.2 Cycle Time. Combined SO_2-flow monitoring systems shall complete a minimum of one cycle of operation (sampling, analyzing, and recording) for each successive 15-min interval.

3.3 Bias. Combined SO_2-flow monitoring systems shall not exhibit low bias as determined by the test procedure in Section 7.5.

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, and a NO_x continuous emissions monitoring system to produce a continuous readout of pollutant mass emission rates in the units of the standard. Where CO_2 emissions are measured with a continuous emission monitoring system, the data acquisition and handling system shall also produce a readout of CO_2 mass emission rates in the appropriate units of the standard.

Data acquisition and handling systems shall compute and record monitor calibration errors; any bias adjustments to pollutant concentration, flow rate, or NO_x emission rate data; and all missing data procedure statistics specified in § 75.12 through § 75.14.

5. Calibration Gas

5.1 Reference Values. Calibration gases shall include the following.

5.1.1 ***Standard Refeence Materials.*** These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, Maryland 20899.

5.1.2 ***EPA Traceability Protocol 1 Gases.*** Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label.

5.1.3 ***NIST/EPA-approved Certified Reference Materials.***

5.2 Concentrations. Three concentration levels are required as follows.

5.2.1 ***Low-level Concentration.*** Zero to 20 percent of span.

5.2.2 ***Mid-level Concentration.*** 40 to 60 percent of span.

5.2.3 ***High-level Concentration.*** 80 to 100 percent of span.

6. Certification Tests and Procedures

6.1 Pretest Preparation. Install the components of the overall continuous emission monitoring system (i.e., pollutant concentration monitors, diluent gas monitor, and flow monitor) as specified in Sections 1, 2, and 3 above, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions.

6.2 Calibration Error Test. With the unit operating at greater than or equal to 50 percent of maximum load, measure the calibration error of each pollutant concentration monitor, diluent gas monitor, and flow monitor that performs daily calibration error tests once a day (at 24-hr intervals) for 7 consecutive days according to the following procedures.

If periodic automatic or manual adjustments are made to the monitor zero and calibration settings, conduct the calibration error test immediately before these adjustments, or conduct it in a way that the magnitude of the calibration error can be determined and recorded.

Introduce the calibration gas at the probe. Conduct the calibration error test for pollutant concentration monitors and diluent gas monitors at the following concentrations: (1) low-level - zero to 20 percent of span, (2) mid-level - 40 to 60 percent of span, and (3) high-level - 80 to 100 percent of span. Challenge the pollutant

concentration monitor three times with each reference gas, but not in succession. Record the monitor response (see example data sheet in Figure 1). For each concentration, use the average of the three responses to determine the calibration error using Equation 7.1.

For flow monitors that perform daily calibration error tests, introduce reference signals to the flow sensor at the following gas flow rates: (1) low-level - the minimum safe and stable operating level, and (2) high-level - the maximum normal operating level. Record the response to each reference signal and calculate the percent difference using Equation 7-1.

Calibration error test results are acceptable for monitor certification if none of the values for the 7-day period exceed the calibration error specifications in Sections 1.3 and 2.3.

6.3 Electronic Drift Test. For flow monitors that do not perform daily calibration error tests, determine the electronic drift of the flow monitor once every 24 hours for 7 consecutive days according to the following procedures.

Introduce, or activate internally, electronic reference signals to the flow sensor at the following levels: (1) low-level - zero to 20 percent of span and (2) high-level - 80 to 100 percent of span. Record the response to each reference signal and calculate the percent difference using Equation 7-1.

Electronic drift test results are acceptable for flow monitor certification if none of the values for the 7-day period exceed the electronic drift specification in Section 2.3.

6.4 Orientation Sensitivity Test. For velocity measurement systems that use the flow direction of the gas, such as differential pressure flow monitors, perform an orientation sensitivity test to ensure proper alignment of the monitor with respect to the axial component of the flue gas flow. While the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel, perform the test according to the following procedures at three gas flow rates: (1) the minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. The flow monitor shall be continuously measuring gas velocity at all times. During the period of relatively steady-state gas flow, rotate the measurement sensor 10.0 degrees on each side of the direction of flow in increments of 5.0 degrees. Perform this test three times at each operating level. Orientation sensitivity test results are acceptable for monitor certification if none of the flow measurements exceed ±4.0 percent of the zero-degree orientation value.

6.5 Cycle Time/Response Time Test. Perform cycle time/response time tests for each pollutant concentration monitor, diluent gas monitor, and NO_x continuous emission monitoring system according to the following procedures. While the monitor or monitoring system is measuring and recording the concentration or emission rate, alternately inject low-level concentration and high-level concentration calibration gases into the injection port until a stable response is reached. Record the amount of time required for the monitor or monitoring system to complete 95.0 percent of the concentration or emission rate stepchange. For monitors or monitoring systems that perform a series of operations (purge, sample analyze, etc.), time the injections of the calibration gases so they will produce the longest possible response time.

Cycle time/response time test results are acceptable for monitor or monitoring system certification if none of the response times exceed 15 min. Beginning on January 1, 2000, a cycle time/response time test will be required for each combined SO_2-flow monitoring system. The response time of the combined system shall not exceed 15 min.

6.6 Relative Accuracy and Bias Tests. Perform relative accuracy test audits for each SO_2 pollutant concentration monitor, flow monitor, and NO_x continuous emission monitoring system, and, beginning January 1, 2000, for each combined SO_2-flow monitoring system. Data from the

relative accuracy test audits shall be used to calculate bias as well as relative accuracy.

Each day during which a relative accuracy test audit is being performed, conduct and record the results of a calibration error test (or electronic drift test for flow monitors that cannot perform daily calibration error tests) prior to any audit runs. Each relative accuracy test audit must be completed within a 7-day period. No adjustments or repairs to the monitor or monitoring system other than routine calibration error checks shall be performed during relative accuracy test audits. Modifications to the SO_2 pollutant concentration monitor, flow monitor, and the NO_x continuous emission monitoring system, e.g., changing the sampling frequency, changing cleaning frequencies, or modifying time-shared systems, are prohibited during the test audits.

Perform relative accuracy test audits for each SO_2 pollutant concentration monitor or NO_x continuous emission monitoring systems at a single unit operating level greater than or equal to 50.0 percent of maximum steam capacity while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel.

Perform relative accuracy test audits for each flow monitor at each of three gas flow rates (or unit operating levels): (1) the minimum safe and stable operating level, (2) 90.0 percent or greater of maximum operating level, and

(3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These test audits shall be performed while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel and must be completed within a 7-day period.

Beginning January 1, 2000, perform relative accuracy test audits for each combined SO_2-flow monitoring system at each of three gas flow rates (or unit operating levels): (1) the minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These combined system test audits shall be performed concurrently with the test audits for the SO_2 pollutant concentration monitor and the flow monitor while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel. The test audits must be completed within a 7-day period.

6.6.1 ***Reference Method Measurement Location.*** Select a location for reference method measurements that is (1) accessible; (2) at least two equivalent diameters downstream from the nearest emission control, the point of pollutant generation, or other point at which a change in the pollutant concentration or flow rate may occur; and (3) at

least a half equivalent diameter upstream from any flow disturbance, such as the discharge to the atmosphere or emission control. The reference method measurement location shall be in the same proximity as the monitor or monitoring system location. The reference method measurement location must meet the requirements of Method 1 in 40 CFR Part 60, Appendix A, for volumetric flow, or Performance Specification 2 in 40 CFR Part 60, Appendix B, for SO_2 and NO_x continuous emission monitoring systems, as appropriate, unless otherwise approved by the Administrator.

6.6.2 *Traverse Point Selection.* Select traverse points that ensure acquisition of representative samples of pollutant concentration, emission rate, and flue gas flow rate over the stack or duct cross section according to the following procedures. Establish a "measurement line" that passes through the centroidal area and in the direction of any expected concentration or flow stratification. If this line interferes with the monitor or monitoring system measurements, displace the line up to 30.0 cm (or 5.0 percent of the equivalent diameter of the cross section, whichever is less) from the centroidal area. Locate three traverse points at 16.7, 50.0, and 83.3 percent of the measurement line. If the measurement line is longer than 2.4 m and concentration or flow rate stratification is not expected, the tester may choose to locate the three traverse points on the line at 0.4, 1.2, and 2.0 m from the stack or

duct wall. The tester may select other traverse points provided that they can be shown, to the satisfaction of the Administrator, to provide a representative sample over the stack or duct cross section. Conduct all reference method tests within 3.0 cm of the traverse points, but not less than 3.0 cm from the stack or duct wall.

6.6.3 *Sampling Strategy.* Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, diluent gas monitor, flow monitor, NO_x continuous emission monitoring system, and combined SO_2-flow monitoring system measurements. Although it is preferable to conduct the diluent (O_2 or CO_2) measurements and any moisture measurements that may be needed simultaneously with the pollutant concentration and flue gas flow rate measurements, diluent and moisture measurements taken within 30-min to 60-min of these measurements will be acceptable for estimating pollutant mass emission rate relative to the heat input of the fuel (lb/mmBtu) or pollutant mass emissions per unit time (lb/hr). In order to properly correlate individual NO_x continuous emission monitoring system, volumetric flow rate, and combined SO_2-flow monitoring system data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart

recorder(s) or other permanent recording device(s) for the pollutant mass emission rate.

Use the following sampling strategies for the reference method tests.

For integrated samples, e.g., Method 6 and Method 4, make a sample traverse of at least 21 min, sampling for 7 min at each traverse point.

For grab samples, e.g., Method 7, take one sample at each traverse point, scheduling the grab samples so that they are taken simultaneously (within a 3-min period) or are spaced in equal intervals of time over a 21-min (or less) period. A test run for grab samples must contain at least three separate measurements.

When testing the relative accuracy of a combined SO_2-flow monitoring system, perform a Method 2 run simultaneously with each SO_2 pollutant concentration reference method test run. Also perform a moisture determination analysis (if needed) using Method 4. The Method 2 velocity traverse points shall be sampled for equal lengths of time and at evenly spaced intervals over the duration of the pollutant concentration sample run.

6.6.4 ***Correlation of Reference Method and Continuous Emission Monitoring System, Flow Rate, and Combined Emission Rates.*** Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, flow, and diluent concentration bases

(e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2 or O_2, lb/hr, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.6.5 ***Number of Reference Method Tests.*** A minimum of nine sets of paired monitor (or monitoring system) and reference method test data shall be performed for every required (i.e., certification, quarterly, semiannual, or annual) relative accuracy or bias test audit. For the certification and periodic quality assurance relative accuracy or bias test audits for flow monitors and combined SO_2-flow monitoring systems, a minimum of nine sets shall be performed at each of the three gas flow rates specified in Section 6.6. Conduct each set within a period of 30 to 60 min. The data set used for the relative accuracy calculation shall also be used for the bias calculation.

NOTE: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen,

the tester may, at his or her discretion, reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. The tester must report all data including the rejected data. All reference method test results including those in preparatory or practice trials shall be reported.

6.6.6 ***Reference Methods.*** Methods 2; 3 or 3A; 4; 6, 6A, 6B, or 6C; and 7, 7A, 7B, 7C, 7D, or 7E from Appendix A of 40 CFR Part 60 or their approved alternatives are the reference methods for velocity, diluent gas (O_2 and CO_2), moisture, SO_2, and NO_x, respectively.

7. Calculations

7.1 Calibration Error. Analyze the calibration error data for pollutant concentration monitors, diluent gas monitors, and flow monitors that perform calibration error tests as follows. Calculate the calibration error as a percentage of the reference value at the low-level, mid-level, and high-level concentrations or reference signals specified in Sections 6.2 and 6.3. Perform this calculation each day during the 7-day certification test. Use the following equation to calculate calibration error.

$$CE = \frac{|R - A|}{R} \times 100 \qquad \text{(Eq. 7-1)}$$

where

CE = Calibration error, as a percentage of the reference value.

R = Low-, mid-, or high-level calibration gas or reference signal introduced into the monitor, monitoring system, or flow sensor analyzer (ppm or other appropriate units). (If the low-level calibration gas or reference signal is zero, use 8.0 ppm or other appropriate units).

A = Average of the three monitor, monitoring system, or analyzer responses to the calibration gas or reference signal (ppm or other appropriate units).

7.2 Electronic Drift. Analyze the electronic drift data for flow monitors that do not perform daily calibration error tests as follows. Calculate the electronic drift as a percentage of the reference value at the low-level, mid-level, and high-level reference signals specified in Section 6.3 using Equation 7-1. Perform this calculation each day during the 7-day certification test.

7.3 Relative Accuracy for SO_2 Pollutant Concentration Monitors, Diluent Gas Monitors, and Flow Monitors. Analyze the relative accuracy test audit data from the reference method tests for SO_2 pollutant concentration monitors, diluent gas monitors, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor

relative accuracy using the following procedures and equations.

7.3.1 *Arithmetic Mean.* Calculate the arithmetic mean of the difference, $\bar{d}$, of a data set as follows.

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} d_i \qquad \text{(Eq. 7-2)}$$

where

n = Number of data points.

$\sum_{i=1}^{n} d_i$ = Algebraic sum of the individual differences d_i.

d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i - CEM_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

7.3.2 *Standard Deviation.* Calculate the standard deviation, S_d, of a data set as follows.

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^{\,2} - \left[\frac{\sum_{i=1}^{n} d_i}{n} \right]^2}{n-1} \right]^{1/2} \qquad \text{(Eq. 7-3)}$$

7.3.3 *Confidence Coefficient.* Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025} \frac{S_d}{\sqrt{n}} \qquad \text{(Eq. 7-4)}$$

where

$t_{0.025}$ = t value (see Table 7-1).

TABLE 7-1. t-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 *Relative Accuracy.* Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100 \qquad \text{(Eq. 7-5)}$$

where

$\overline{RM}$ = Arithmetic mean of the reference method values.

Units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is

less than or equal to 250.0 ppm may use an alternative standard for SO_2 pollutant concentration monitor relative accuracy defined in terms of $|\bar{d}|$. For these units, $|\bar{d}|$ shall not exceed 15.0 ppm.

Units where the average of the flow monitor measurements of stack gas velocity during the relative accuracy test audit is less than or equal to 10.0 fps may use an alternative standard for flow monitor relative accuracy, defined in terms of $|\bar{d}|$. For these units, $|\bar{d}|$ shall not exceed 1.0 fps.

7.4 Relative Accuracy for NO_x Continuous Emission Monitoring Systems. Analyze the relative accuracy test audit data from the reference method tests for NO_x continuous emissions monitoring system as follows.

7.4.1 *NO_x Emission Rate (Instrumental Method).* For each Method 7E sample run, multiply C_{NOx}, the NO_x concentration in ppm, by 1.194×10^{-7} (lb/dscf)/ppm, to convert it to units of lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run to convert C_{NOx} from lb/dscf to lb/mmBtu units. Use Equation 2-3 or 2-4 in Appendix E of this part, as appropriate.

7.4.2 *NO_x Emission Rate (Wet Chemistry).* For each Method 7, 7A, 7B, 7C, or 7D sample run, calculate C_{NOx}, the NO_x concentration expressed as NO_2, using the data reduction procedures in the applicable method. For grab samples, C_{NOx} is the average of all samples taken during the run. If C_{NOx}

is in mg/dscm, multiply by 6.24 x 10^{-8} to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run to convert from lb/dscf to lb/mmBtu. Use Equation 2-3 or 2-4 in Appendix E of this part, as applicable.

7.4.3 *NO_x Emission Rate (Monitoring System).* For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 2.

7.4.4 *Relative Accuracy.* Use the equations and procedures in Section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using Equation 7-2, "d" shall, for each run, be the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

Units where the average of the monitoring system measurements during the relative accuracy test audit is less than or equal to 0.50 lb/mmBtu may use an alternative standard for NO_x continuous emission monitoring system relative accuracy defined in terms of $|\bar{d}|$. For these units, $|\bar{d}|$ shall not exceed 0.05 lb/mmBtu.

7.5 Relative Accuracy for Combined SO_2-Flow Monitoring Systems. Beginning on January 1, 2000, use the equations and procedures in Section 7.3 above to calculate the

relative accuracy for the combined SO_2-flow monitoring system. In using Equation 7-2, "d" shall, for each run, be the difference between the SO_2 emission rate values (in lb/hr) obtained from the reference method data for SO_2 concentration and flow rate and the combined SO_2-flow monitoring system.

7.6 Bias Test and Adjustment Factor. Test the relative accuracy test audit data sets for SO_2 pollutant concentration monitors, flow monitors, NO_x continuous emission monitoring systems and, beginning January 1, 2000, for combined SO_2-flow monitoring systems for bias using the procedures outlined below.

7.6.1 ***Arithmetic Mean.*** Calculate the arithmetic mean of the difference, $\bar{d}$, of the data set using Equation 7-2. To calculate bias for an SO_2 pollutant concentration monitor, "d" shall, for each paired data point, be the difference between the SO_2 concentration values (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" shall, for each paired data point be the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x continuous emission monitoring system, "d" shall, for each paired data point, be the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system. To calculate bias for a combined SO_2-

flow monitoring system, "d" shall, for each paired data point, be the difference between the SO_2 mass emissions per unit time (in lb/hr) obtained from the reference methods and the monitoring system.

Bias tests for flow monitors and, beginning on January 1, 2000, for combined SO_2-flow monitoring systems shall be performed at the normal operating level only.

7.6.2 ***Standard Deviation.*** Calculate the standard deviation, S_d, of the data set using Equation 7-3.

7.6.3 ***Confidence Coefficient.*** Calculate the confidence coefficient, cc, of the data set using Equation 7-4.

7.6.4 ***Bias Test.*** If the mean difference, $\bar{d}$, is greater than |cc|, the monitor or monitoring system has failed to meet the bias test requirement. For flow monitor bias tests and, beginning on January 1, 2000, for combined SO_2-flow monitoring system bias tests, if the mean difference, d is greater than |cc| at the normal operating level, the monitor has failed to meet the bias test requirement.

7.6.5 ***Bias Adjustment.*** If the monitor or monitoring system fails to meet the bias test requirement, the owner or operator shall adjust the values obtained from the monitor using the following equation.

$$CEM_i^{Adjusted} = CEM_i^{Monitor}\left(1+\frac{|\bar{d}|}{\overline{CEM}}\right) \qquad (Eq.7-6)$$

where

$CEM_i^{Monitor}$ = Data (measurements) provided by the monitor at time i.

$CEM_i^{Adjusted}$ = Data value, adjusted for bias, at time i.

$\bar{d}$ = Arithmetic mean of the difference obtained during the failed bias test using Equation 7-2.

$\overline{CEM}$ = Mean of the data values provided by the monitor during the failed bias test.

This adjustment shall be applied prospectively to all monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

	Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level						
Mid-level						
High-level						

Figure 1. Calibration error determination.

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Run No.	Date and time	SO_2			Date and time	NO_x [b]			Date and time	CO_2 or O_2 [a] (Diluent)			Date and time	CO_2 (Pollutant)		
		RM	M	Diff		RM	M	Diff		RM	M	Diff		RM	M	Diff
		ppm [c]				ppm [c]				% [c]	% [c]			ppm [c]		
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
11																
12																
Average																
Confidence Interval																
Accuracy																

[a] For steam generators

[b] Average of three samples, if grab-sampling is used.

[c] Make sure that RM and M data are on a consistent basis, either wet or dry.

Figure 2: Relative accuracy determination (pollutant and diluent monitors).

Run No.	Date and time	Stack moisture			Date and time	Flow rate (40%)			Date and time	Flow rate (60%)			Date and time	Flow rate (90%)		
		RM	M	Diff		RM	M	Diff		RM	M	Diff		RM	M	Diff
		% H_2O				(scf/hr) *				(scf/hr) *				(scf/hr) *		
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
11																
12																
Average																
Confidence Interval																
Accuracy																

* Make sure that RM and M data are on a wet basis.

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Figure 2 (cont'd): Relative accuracy determination (moisture and flow monitors).

Run No.	Date and time	NO_x RM data		NO_x system		
		NO_x	O_2/CO_2	RM	M	Diff
		( ) [a]	%	lb/mmBtu		
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Average						
Confidence Interval						
Accuracy						

[a] Specify units; ppm, lb/dscf, mg/dscm

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Figure 2 (cont'd): Relative accuracy determination (NO_x/diluent combined system).

APPENDIX B - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

1. Quality Control Program

Each owner or operator of an affected unit shall develop and implement a quality control program for the overall continuous emission monitoring system and its components. As a minimum, each quality control program must include a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities.

1.1 Calibration Error Test Procedures. Identify calibration error test procedures peculiar to the continuous emission monitoring system that may require variance from the procedures in Appendix A of this part (e.g., how gases shall be injected, adjustments of flow rates and pressures, length of time for injection of calibration gases, steps for obtaining calibration error, and when calibration adjustments should be made).

1.2 Calibration Adjustments. Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases and reference signals both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of the continuous emission monitoring system.

1.3 Preventive Maintenance. Identify procedures, including those specified by the manufacturers, needed to maintain the continuous emission monitoring system in proper operating condition. Include provisions for maintaining an inventory of spare parts.

1.4 Audit Procedures. Identify procedures and details peculiar to the installed continuous emission monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.5 Recordkeeping and Reporting. Describe procedures that will be used to implement the recordkeeping and reporting requirements in § 75.22 and § 75.23 of the regulation.

2. Quality Assurance Procedures

2.1 Daily Assessments

2.1.1 ***Calibration Error Tests for Pollutant Concentration and Diluent Gas Monitors.*** Test, record, and compute the calibration error of each pollutant concentration and diluent gas monitor at least once daily (approximately every 24 hr) at two concentrations: (1) low-level - zero to 20 percent of span, and (2) high-level - 80 to 100 percent of span. Perform daily calibration error tests in accordance with the procedures and equations in Sections 6 and 7 of Appendix A of this part and use only Protocol 1, NIST/EPA-approved certified reference material, or standard reference material gases. Do not make

calibration adjustments for low-level concentration measurements before completion of the high-level concentration calibration error checks. Perform daily calibration error tests for both ranges of a dual-range monitor.

2.1.2 ***Calibration Error or Electronic Drift Test for Flow Monitors.*** Perform manufacturer-recommended zero and calibration procedures on each flow monitor daily, or more frequently if recommended by the manufacturer. Record flow monitor output before and after any adjustments. Set instrument span so that the average volumetric flow lies between 40.0 and 75.0 percent of span. Whenever the monthly average volumetric flow falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the average volumetric flow is within the cited ranges.

Test, record, and quantify the calibration error of each flow monitor that performs daily calibration error tests (approximately every 24 hours) at two gas flow rates: (1) low-level - the minimum safe and stable operating level, and (2) high-level - the maximum normal operating level. Daily calibration error tests for flow monitors must provide a check of the entire measurement system from the probe tip through the data acquisition and handling system.

Test, record, and quantify the electronic drift of each flow monitor that does not perform daily calibration error tests at two electronic signal levels: (1) 45 to 75 percent

of span, and (2) 80 to 100 percent of span. Daily electronic drift tests for flow monitors must provide a check of all electronic components of the flow monitor.

2.1.3 *Recalibration.* The calibration must, at a minimum, be adjusted whenever the daily calibration error exceeds the limits of the applicable performance specification for the pollutant concentration monitor, diluent gas monitor, or flow monitor in Appendix A of this part.

2.1.4 *Out-of-Control Period.* An out-of-control period occurs when the calibration error or electronic drift exceeds twice the applicable specification (i.e., when the calibration error of a pollutant concentration monitor exceeds 5.0 percent, the calibration error of a diluent gas monitor exceeds 1.0 percent, or the calibration error or electronic drift of a flow monitor exceeds 6.0 percent). The out-of-control period begins with the hour of the failed calibration error or electronic drift test and ends with the hour of the satisfactory calibration error or electronic drift test following recalibration or corrective action.

2.1.5 *Data Recording.* Record and tabulate all calibration error and electronic drift test data according to month, day, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) the unadjusted concentration

or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment.

2.1.6 ***Interference Check.*** For ultrasonic and differential pressure flow monitors, perform automatic timed periodic back purging (simultaneously on both sides of the probe), or equivalent method of sufficient force and frequency to keep the transceiver surface/sample port, and the probe and lines, respectively, free of obstructions. Inspect and clean the probe of thermal flow monitors at a frequency (daily if necessary) that ensures that the probe remains clean at all times.

An out-of-control period occurs whenever an interference is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour following removal of the interference.

2.2 Quarterly Assessments

2.2.1 ***Three-Point Calibration Error Test.*** Perform a three-point calibration error test for each pollutant concentration and diluent gas monitor at least once during each calendar quarter (approximately every 3 months) in accordance with the following procedures.

Challenge each pollutant concentration or diluent gas monitor with Protocol 1, NIST/EPA-approved certified reference material, or standard reference material calibration gases at the three concentrations specified in

Section 5.2 in Appendix A of this part. Perform separate calibration error tests for each range of a dual-range monitor.

Introduce the calibration gas at the probe. Operate each monitor in its normal sampling mode, i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. Challenge the monitor three times, but not in succession, at each concentration. For each concentration, use the average of the three responses to determine the calibration error. Use separate audit gas cylinders for each concentration.

2.2.2 *Interference Checks.* Perform a leak check and pressure transducer check on each differential pressure flow monitor at least once during each calendar quarter.

2.2.3 *Relative Accuracy Test Audits for Flow Monitors.* Perform a relative accuracy test audit for each flow monitor that does not perform daily calibration error tests at least once during each calendar quarter in accordance with the procedures specified in Section 6.6 of Appendix A of this part. (Quarterly test audits shall be performed at normal operating load and shall be no less than two months apart). However, a relative accuracy test audit may be performed during the second quarter following a relative accuracy test audit instead of the next consecutive quarter under the following conditions: (1) prior to January 1, 2000, when the

relative accuracy is 10.0 percent or less during the previous audit; and (2) on and after January 1, 2000, when the relative accuracy is 7.5 percent or less during the previous audit. Using the data from the relative accuracy test audit, calculate relative accuracy and bias for each flow monitor in accordance with the procedures and equations specified in Section 7 of Appendix A of this part.

A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required for less frequent relative accuracy test audits. Whenever two trials are performed, however, the results of the second (later) trial must be used in calculating relative accuracy and bias.

2.2.4 *Out-of-Control Period.* An out-of-control period occurs under any of the following conditions: (1) the calibration error at any of the three concentrations or flow rates in the quarterly three-point calibration error test exceeds twice the applicable specification in Section 2.3 of Appendix A of this part, or (2) prior to January 1, 2000, the relative accuracy of the flow monitor exceeds 15.0 percent, or (3) on and after January 1, 2000, the relative accuracy of the flow monitor exceeds 10.0 percent. The out-of-control period begins with the hour of the failed three-point calibration error test or relative accuracy test audit and ends with the hour of a satisfactory three-point

calibration error test or relative accuracy test audit following corrective action and/or monitor repair.

2.2.5 *Bias Adjustment Factor.* If a flow monitor fails the bias test specified in Section 7.6 of Appendix A of this part, the owner or operator shall use the bias adjustment factor given by Equation 7-6 to adjust the monitored data. This adjustment factor shall be applied prospectively to the flow monitor data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.3 Semiannual Assessments

2.3.1 *Relative Accuracy Test Audit.* Perform a component and system relative accuracy test audit semiannually and no less than 4 months apart for each SO_2 pollutant concentration monitor, flow monitor that performs daily calibration error tests, and NO_x continuous emission monitoring system, and, beginning January 1, 2000, combined SO_2-flow monitoring system.

Relative accuracy test audits may be performed on an annual basis in the fourth quarter following a relative accuracy test audit rather than on a semiannual basis in the second quarter under any of the following conditions: (1) the relative accuracy during the previous audit for an SO_2 pollutant concentration monitor or NO_x continuous emissions monitoring system is 7.5 percent or less; (2) prior to January 1, 2000, the relative accuracy during the previous

audit for a flow monitor is 10.0 percent or less; (3) on and after January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 7.5 percent or less. A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits. Whenever two trials are performed, however, the results of the second (later) trial must be used in calculating relative accuracy and bias.

2.3.2 *Out-of-Control Period.* An out-of-control period occurs under any of the following conditions: (1) the relative accuracy of an SO_2 pollutant concentration monitor or a NO_x continuous emission monitoring system exceeds 10.0 percent; (2) prior to January 1, 2000, the relative accuracy of a flow monitor exceeds 15.0 percent; or (3) on and after January 1, 2000, the relative accuracy of a flow monitor exceeds 10.0 percent. The out-of-control period begins with the hour of the failed relative accuracy test audit and ends with the hour of a satisfactory relative accuracy test audit following corrective action and/or repair of the monitor or monitoring system.

2.3.3 *Bias Adjustment Factor.* If an SO_2 pollutant concentration monitor, flow monitor, or NO_x continuous emission monitoring system fails the bias test specified in Section 7.6 of Appendix A of this part, the owner or operator shall use the bias adjustment factor given by

Equation 7-6 to adjust the monitored data. This adjustment factor shall be applied prospectively to the monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.4 Annual Assessments

2.4.1 ***Three-Level Relative Accuracy Test Audit for Flow Monitors.*** Perform relative accuracy test audits for each flow monitor at each of three gas flow rates (or unit operating levels): (1) the minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These test audits shall be performed while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel and must be completed within a 7-day period.

Using the data from the relative accuracy test audits, calculate monitor relative accuracy at each of the three flow rates (operating levels) and bias at the normal operating level in accordance with the procedures and equations specified in Section 7 of Appendix A of this part.

2.4.2 ***Relative Accuracy Test Audit for Combined SO_2-Flow Monitoring System.*** Beginning January 1, 2000, at least once every four calendar quarters, perform relative accuracy

test audits for each combined SO_2-flow monitoring system at each of three gas flow rates (or unit operating levels): (1) the minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These combined system test audits shall be performed concurrently with the test audits for the SO_2 pollutant concentration monitor and the flow monitor while the unit (or units, if more than one unit exhausts into the stack or duct) is burning primary fuel. The test audits must be completed within a 7-day period.

Using the data from the relative accuracy test audits, calculate the relative accuracy of the combined SO_2-flow monitoring system at each of the three flow rate (operating levels) and bias at the normal operating level in accordance with the procedures and equations specified in Section 7 of Appendix A of this part.

2.4.3 ***Out-of-Control Period.*** An out-of-control period occurs under any of the following conditions: (1) prior to January 1, 2000, the relative accuracy of a flow monitor at any of the three operating levels exceeds 15.0 percent; (2) on or after January 1, 2000, the relative accuracy of a flow monitor at any of the three operating levels exceeds 10.0 percent; or (3) on and after January 1, 2000, the relative

accuracy of a combined SO_2-flow monitoring system exceeds 10.0 percent at any of the three operating levels. The out-of-control period begins with the hour of the failed three-level relative accuracy test audit and ends with the hour of a satisfactory three-level relative accuracy test audit following corrective action and/or repair of the monitor or monitoring system.

2.4.4 ***Bias Adjustment Factor.*** If a flow monitor fails the bias test specified in Section 7.6 of Appendix A of this part, the owner or operator shall use the bias adjustment factor give by Equation 7-6 of Appendix A to adjust the monitored data. This adjustment factor shall be applied prospectively to the monitor data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.4.5 ***Other Audits.*** Affected units may be subject to unannounced relative accuracy test audits at any time. If a monitor or monitoring system fails the relative accuracy test during the unannounced audit, the monitor or monitoring system shall be considered to be out of control beginning with the date and time of the unannounced audit and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an unannounced audit, the owner or operator shall use the bias adjustment factor given by Equation 7-6 in Appendix A of this part to adjust the

monitored data. This adjustment factor shall be applied from the date and time of the unannounced audit until the date and time of a relative accuracy test audit that does not show bias.

APPENDIX C - MISSING DATA STATISTICAL ESTIMATION PROCEDURES

1. Parametric Monitoring Procedure for Missing SO_2 Concentration Data

1.1 Applicability. The owner or operator of any affected unit equipped with flue gas SO_2 emission controls and inlet and outlet SO_2 pollutant concentration monitors may apply to the Administrator for approval and certification of a parametric method for calculating substitute data for missing data periods. Such method may be used to parametrically estimate the removal efficiency of the SO_2 emission controls which, with the monitored SO_2 inlet concentration data, may be used to estimate the average concentration of SO_2 emissions discharged to the atmosphere. Such method may be used subsequent to approval by the Administrator for filling in missing SO_2 concentration data when data from the outlet SO_2 pollutant concentration monitor have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 days.

1.2 Demonstration Requirements. Continuously monitor, determine, and record hourly averages for the parameters specified below. At least four evenly spaced data points are required for a valid hourly average, except during periods of calibration, quality assurance, maintenance or repair activities, during which two data points per hour are sufficient.

1.2.1 Wet Flue Gas Desulfurization System (Wet Scrubber).

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Feed rate of makeup slurry to each scrubber module (gal per min).

1.2.1.3 Percent solids in slurry.

1.2.1.4 pH of the solids slurry in each scrubber module.

1.2.1.5 Pressure differential across each scrubber module (inches of water column).

1.2.1.6 Power load of unit (MWe).

1.2.1.7 Average sulfur content of fuel combusted each day (lb/mmBtu).

1.2.2 Dry Flue Gas Desulfurization System (Dry Scrubber).

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Feed rate of makeup slurry to each scrubber module (gal per min).

1.2.2.3 Percent solids in slurry.

1.2.2.4 Dew point approach temperature for each scrubber module (degrees Fahrenheit).

1.2.2.5 Pressure differential across each scrubber module (inches of water column).

1.2.2.6 Power load of unit (MWe).

1.2.2.7 Average sulfur content of fuel combusted each day (lb/mmBtu).

1.2.3 If a technology other than conventional wet or dry scrubbing is selected for flue gas desulfurization, then appropriate parameters will be determined at the discretion of the Administrator on a case-by-case basis.

1.2.4 Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 emission controls under varying unit operating loads. Equation 2 in § 75.12(d) of this part may be used to estimate the percent removal efficiency of the SO_2 emission controls.

1.2.5 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

$$M_o = I_c (1-E) \qquad \text{(Eq. 1-1)}$$

where

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in Section 1.2.4.

1.2.6 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, the maximum inlet SO_2 concentration for the corresponding unit load recorded during the previous 30 days shall be used to substitute for the inlet SO_2 concentration in Equation 1-1.

1.2.7 The owner or operator shall apply to the Administrator for approval and certification of the

parametric substitution procedure for filling in missing SO_2 concentration data using the established criteria and information identified above. Such procedure shall not be used until approved by the Administrator.

2. Parametric Monitoring Procedure For Missing NO_x Emission Rate Data

2.1 Applicability. The owner or operator of an affected unit equipped with post-combustion NO_x emission controls and inlet and outlet NO_x continuous emission monitoring systems (NO_x pollutant concentration monitor and diluent gas monitor) may apply to the Administrator for approval and certification of a parametric method for calculating substitute data for missing data periods. Such method may be used to parametrically estimate the removal efficiency of the post-combustion NO_x emission controls which, with monitored NO_x inlet emission rate data, may be used to estimate the average emission rate of NO_x discharged to the atmosphere. Such method may be used subsequent to approval by the Administrator for filling in missing NO_x emission rate data when data from the outlet NO_x continuous emission monitoring system have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 days.

2.2 Demonstration Requirements

2.2.1 Continuously monitor, determine, and record hourly averages for the parameters specified below. At

least four data points are required for a valid hourly average, except during periods of calibration, quality assurance, maintenance or repair activities, during which two data points per hour are sufficient.

2.2.1.1 Inlet air flow rate to the unit (scfh).

2.2.1.2 Excess oxygen concentration of flue gas at stack outlet (percent).

2.2.1.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

2.2.1.4 Temperature of flue gas at outlet of the unit (degrees Fahrenheit).

2.2.1.5 Other parameters of the post-combustion NO_x emission controls specific to the emission reduction process.

2.3 Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the post-combustion NO_x emission controls under varying unit operating loads.

2.4 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

$$M_o = I_c (1-E) \qquad \text{(Eq. 2-1)}$$

where

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in Section 2.3.

2.5 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, the maximum inlet NO_x emission rate for the corresponding unit load recorded during the previous 30 days shall be used to substitute for the inlet NO_x emission rate in Equation 2-1.

2.6 The owner or operator shall apply to the Administrator for approval and certification of the substitute procedure for filling in missing NO_x emission rate data using the established criteria and information identified above. Such procedure shall not be used until approved by the Administrator.

3. Load-Based Procedure for Missing Flow Rate and NO_x Emission Rate Data

3.1 Applicability. This procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow (scfh) and NO_x emission rate (lb/mmBtu).

3.2 Procedure

3.2.1 Establish 13 operating load ranges defined in terms of percent of the maximum integrated hourly gross load of the unit, in gross megawatts (MWge) as shown in Table C-1.

Table C-1. Definition of Operating Load Ranges for Load-Based Substitution Data Procedure

Operating Load Range	Percent of Maximum Integrated Hourly Gross Load (%)
1	1 - 20
2	21 - 40
3	41 - 50
4	51 - 55
5	56 - 60
6	61 - 65
7	66 - 70
8	71 - 75
9	76 - 80
10	81 - 85
11	86 - 90
12	91 - 95
13	96 - 100

3.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor and the NO_x continuous emission monitoring system and continuing during each consecutive 365 days of operation of the monitor and monitoring system thereafter, calculate and record the following information for each hour of unit operation.

3.2.2.1 A number, 1 through 13, that identifies the operating load range corresponding to the integrated hourly gross load of the unit recorded for that hour.

3.2.2.2 A running average of the hourly flow rates recorded by the flow monitor, in scfh, for all hours the unit operated within the identified load range during the previous 365 days of operation of the flow monitor.

3.2.2.3 The 90th percentile value of hourly flow rates, in scfh, within the identified operating load range

during the previous 365 days of operation of the flow monitor.

3.2.2.4 The 90th percentile value of hourly flow rates, in scfh, within the identified operating load range during the previous 30 days of operation of the flow monitor.

3.2.2.5 A running average of the hourly NO_x emission rate, in lb/mmBtu, for all hours of operation within the identified operating load range during the previous 365 days of operation of the NO_x continuous emissions monitoring system.

3.2.2.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu, within the identified operating load range during the previous 365 days of operation of the NO_x continuous emissions monitoring system.

3.2.2.7 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu, within the identified operating load range during the previous 30 days of operation of the NO_x continuous emissions monitoring system.

3.2.3 When a bias adjustment is necessary for the flow monitor and/or the NO_x continuous emission monitoring system, use the adjusted monitor or monitoring system data in all determinations of averages and 90th percentile values within a load range.

3.2.4 Use the calculated averages and 90th percentile values to substitute for missing flow rate and NO_x emission

rate data according to the procedures in § 75.12 and § 75.13 of this part.

4. Sulfur Content-Based Procedure for Missing SO_2 Concentration Data

4.1 Applicability. This procedure may be used in accordance with the provisions of this part to provide substitute data for SO_2 concentration (ppm).

4.2 Procedure

4.2.1 Sample (as-fired after the bunker), analyze, and record the percent of sulfur by weight in the fuel combusted once each 6 hours. For coal, collect a sample in accordance with ASTM D2234-89, "Standard Test Methods for Collection of a Gross Sample of Coal" using Type I, Condition B or C sampling, and perform the analysis in accordance with ASTM D3176-89, "Standard Method for Ultimate Analysis of Coal and Coke" or ASTM D3177-89, "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke" (incorporated by reference in § 75.9). For oil, perform the analysis in accordance with ASTM D129, ASTM D1552, ASTM D2622, or ASTM D4294 (incorporated by reference in § 75.9).

4.2.2 Establish 25 sulfur content ranges to include values from zero to greater than 6 percent sulfur content in the fuel combusted by the unit, where sulfur content is defined in terms of the percent sulfur by weight measured in the fuel. Define each sulfur content range to span 0.25 percent sulfur as shown in Table C-2.

TABLE C-2. DEFINITION OF SULFUR CONTENT RANGES FOR SULFUR CONTENT-BASED SUBSTITUTION DATA PROCEDURE

Sulfur Content Range	Percent of Sulfur Measured in Fuel (%)
1	0.00 - 0.25
2	0.26 - 0.50
3	0.51 - 0.75
4	0.76 - 1.00
5	1.01 - 1.25
6	1.26 - 1.50
7	1.51 - 1.75
8	1.76 - 2.00
..	.... - ....
24	5.76 - 6.00
25	>6.00

4.2.3 Beginning with the first hour of unit operation after installation and certification of the SO_2 pollutant concentration monitor and continuing during each consecutive 365 days thereafter, calculate and record the following information for each 6-hr period of unit operation.

4.2.3.1 A number, 1 through 25, that identifies the sulfur content range corresponding to the percent sulfur measured in the fuel for the 6-hr period. Include each of the hourly SO_2 concentrations recorded by the SO_2 pollutant concentration monitor during the 6-hr period in the identified sulfur content range for the purpose of calculating 90th percentile values.

4.2.3.2 The 90th percentile value of the hourly SO_2 concentrations, in ppm, within the identified sulfur content range during the previous 365 days of operation.

4.2.3.3 The 90th percentile value of the hourly SO_2 pollutant concentrations, in ppm, within the identified sulfur content range during the previous 30 days of operation.

4.2.4 When a bias adjustment is necessary for the SO_2 pollutant concentration monitor, use the adjusted monitor data in all determinations of 90th percentile values within a sulfur content range.

4.2.5 Use the calculated 90th percentile values to substitute for missing SO_2 concentration data according to the procedures in § 75.11 of this part. Whenever a sulfur content range has fewer than 20 hourly values of SO_2 concentration recorded by the SO_2 pollutant concentration monitor, use the next higher sulfur content range that has at least 20 values for each substitution involving 90th percentile calculations (unless there is no higher range that has at least 20 values).

4.2.6 To identify the appropriate sulfur content range for each hour of missing data, use the measured percent sulfur by weight in the fuel taken for that hour or, if no sample was taken during the missing hour, use the average of the measured percent sulfur by weight in the fuel for the 6-hr sample immediately before and the 6-hr sample immediately following the missing hour.

APPENDIX D - OPTIONAL SO_2 EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

1. Applicability

This procedure may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from: (1) gas-fired units that use fuel oil (including diesel fuel) as the only backup fuel where oil firing provides less than 10.0 percent of the annual heat input to the unit; or (2) oil-fired units that use natural gas as the only other fuel where oil firing provides 10.0 percent or more of the annual heat input to the unit.

2. Procedure

2.1 When the unit is combusting oil, measure and record the flow of oil consumed on an hourly basis. The flow of oil must be measured with an in-line fuel flowmeter and the data automatically recorded. Measure the flow of all oil entering the unit. Any pipe returning fuel to a pipe that provides oil to the unit requires an in-line fuel flowmeter.

2.1.1 Each fuel flowmeter used to meet the requirements of this protocol shall meet a relative accuracy specification of 2.0 percent as measured under laboratory conditions by the manufacturer or by the owner or operator.

2.1.2 Recalibrate each fuel flowmeter at least annually or more frequently if required by manufacturer specifications to meet the requirements of this protocol.

2.2 Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 Perform oil sampling every day the unit is combusting oil. Use the standard method described in Section 2.2.1.1 below for oil-fired units and either the standard method or the exception method described in Section 2.2.1.2 below for gas-fired units.

2.2.1.1 *Standard Method for Oil Sampling.* Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM 4177, "Standard Method for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.9), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample compositing period may not exceed 24 hr.

2.2.1.2 *Exception.* For a gas-fired unit, representative, as-fired oil samples may be taken manually every 24 hr according to ASTM D4057, "Standard Method for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.9), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating SO_2 emissions under Section 2.9.

2.2.2 Split and label each daily oil sample. Maintain a portion of each daily sample throughout the calendar year

(at least 200 cc) for not less than 6 months after December 31 of that year.

2.2.3 Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129, ASTM D1552, ASTM D2622, or ASTM D4294 (incorporated by reference under § 75.9).

2.3 Where the flowmeter records volumetric flow rather than mass flow, analyze daily oil samples to determine the density or specific gravity of the oil.

2.3.1 Determine the density or specific gravity of the oil sample in accordance with ASTM D941-88, ASTM D1217-86, ASTM D1481-86, ASTM D1480-86, ASTM D1298-85, or ASTM D4052-86 (incorporated by reference under § 75.9).

2.3.2 Convert oil volume to oil mass using ASTM D1250-80 (Reapproved 1984), "Standard Petroleum Measurement Tables" (incorporated by reference under § 75.9).

2.3.3 Calculate hourly oil mass using hourly oil flow measurements and the density or specific gravity of the daily oil sample.

2.4 Analyze daily oil samples to determine the heat content of the fuel.

2.4.1 Determine oil heat content in accordance with ASTM D240-87 or D2382-88 (incorporated by reference under § 75.9).

2.4.2 Calculate the hourly heat input to the unit from oil by multiplying the heat content of the daily oil sample by the hourly oil mass.

2.5 Results from the daily oil sample analysis must be available the day after the sample is composited or taken.

2.6 When data from a daily oil sample analysis are missing or invalid, substitute the highest measured sulfur content or oil density recorded during the previous 365 days.

2.7 When data from the fuel flowmeter are missing or invalid for less than 24 hr, substitute for each hour in the missing data period the average hourly oil flow rate recorded by the fuel flowmeter during the previous 365 days at the same unit load (in MWe) recorded for the missing hour. If no data are available at the same unit load, use the average hourly oil flow rate recorded at the closest, higher unit load.

2.8 When data from the fuel flowmeter are missing or invalid for more than 24 hr, substitute for each hour in the missing data period the second highest hourly oil flow rate measured by the fuel flowmeter during the previous 365 days.

2.9 Calculate total SO_2 mass emissions for each hour by multiplying the mass of oil consumed in lb/hr times the percentage of sulfur in oil by weight times 2.0.

2.9.1 Use the following equation to calculate SO_2 mass emissions per hour (in lb/hr).

$$M_{SO2} = 2.0 \times M_{oil} \times \%S_{oil}/100.0 \qquad \text{(Eq. 2-1)}$$

where

M_{SO2} = Hourly mass of SO_2 emitted, lb/hr.

M_{oil} = Mass of oil consumed per hr, lb/hr.

$\%S_{oil}$ = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of g-mol SO_2/g-mol S.

2.9.2 Where the flowmeter records volumetric flow rather than mass flow, use the following equation to calculate the mass of oil consumed (in lb/hr).

$$M_{oil} = V_{oil} \times D_{oil} \qquad \text{(Eq. 2-2)}$$

where

M_{oil} = Mass of oil consumed per hr, lb/hr.

V_{oil} = Volume of oil consumed per hr, measured in scf, gal, or m^3.

D_{oil} = Density of oil, measured in lb/gal, lb/scf, or lb/m^3.

2.9.3 Calculate and record total daily SO_2 mass emissions by summing the hourly SO_2 mass emissions for each hour during that day when the unit combusted any oil.

2.9.4 Calculate and record total quarterly SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that quarter when the unit combusted any oil.

2.9.5 For purposes of determining compliance with allowances held, calculate and record the total SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that year when the unit combusted any oil.

APPENDIX E - CONVERSION PROCEDURES

1. Applicability

Each owner or operator of an affected unit shall use the procedures in this appendix to convert measured data from the monitor or continuous emission monitoring system into the appropriate units required by the regulation in this part.

2. Procedures

2.1 SO_2. Use the following procedures to compute the hourly emission rates of SO_2 in lb/hr.

2.1.1 When measurements of both SO_2 pollutant concentration and flow rate are on the same moisture basis, use the following equation to compute SO_2 hourly emission rates (in lb/hr).

$$E_h = K\ C_h\ Q_h \qquad \text{(Eq. 2-1)}$$

where

E_h = Hourly emission rate of SO_2, lb/hr.

K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_h = Hourly average pollutant concentration of SO_2, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate, stack moisture basis, scfh.

2.1.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute SO_2 hourly emission rates (in lb/hr).

$$E_h = K\ C_{hp}\ Q_{hs}\ (1 - B_{we}) \qquad \text{(Eq. 2-2)}$$

where

E_h = Hourly emission rate of SO_2, lb/hr.

K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_{hp} = Hourly average pollutant concentration, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate, scfh as measured (wet).

B_{ws} = Hourly average stack moisture content, volume fraction.

2.1.3 Round all SO_2 emission rates to the same number of significant digits that are identified by the regulation (in lb/hr), but in no case less than the nearest 10 lb/hr. When hourly SO_2 emission rates are less than 1,000 lb/hr, round the emission rates to the nearest 1 lb/hr.

2.2 NO_x. Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Measurements of NO_x and diluent (O_2 or CO_2) concentrations must be performed on the same moisture (wet or dry) basis.

2.2.1 When the NO_x continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = CF[20.9/(20.9-\text{percent } O_2)] \qquad \text{(Eq. 2-3)}$$

where E, C, F, and percent O_2 are defined in Section 2.2.3. When measurements are performed on a wet basis, use the equations in 40 CFR Part 60, Appendix A, Method 19.

2.2.2 When the NO_x continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

$$E = CF_c[100/\text{percent } CO_2] \qquad \text{(Eq. 2-4)}$$

where E, C, F_c, and percent CO_2 are defined in Section 2.2.3.

2.2.3 Use the definitions listed below to derive values for the parameters in Equations 2-3 and 2-4.

2.2.3.1 E = pollutant emissions, lb/mmBtu.

2.2.3.2 C = pollutant concentration, lb/dscf, determined by multiplying the average concentration (ppm) for each 1-hr period by 1.19×10^{-7} lb/dscf per ppm.

2.2.3.3 Percent O_2, percent CO_2 = oxygen or carbon dioxide volume (expressed as percent).

2.2.3.4 F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows.

2.2.3.4.1 For anthracite coal as classified according to ASTM D388-90 (incorporated by reference under § 75.9), F = 10,100 dscf/mmBtu and F_c = 1,970 scf CO_2/mmBtu.

2.2.3.4.2 For subbituminous and bituminous coal as classified according to ASTM D388-90 (incorporated by reference under § 75.9), F = 9,780 dscf/mmBtu and

F_c = 1,800 scf CO_2/mmBtu.

2.2.3.4.3 For liquid fossil fuels including crude, residual, and distillate oils, F = 9,190 dscf/mmBtu and F_c = 1,420 scf CO_2/mmBtu.

2.2.3.4.4 For gaseous fossil fuels, F = 8,710 dscf/mmBtu. For natural gas, propane, and butane fuels, F_c = 1,040 scf CO_2/mmBtu for natural gas, 1,190 scf CO_2/mmBtu for propane, and 1,250 scf CO_2/mmBtu for butane.

2.2.3.4.5 For bark, F = 9,600 dscf/mmBtu and F_c = 1,920 scf CO_2/mmBtu. For wood residue other than bark, F = 9,240 dscf/mmBtu and F_c = 1,830 scf CO_2/mmBtu.

2.2.3.4.6 For lignite coal as classified according to ASTM D388-77 (incorporated by reference under § 75.9), F = 9,860 dscf/mmBtu and F_c = 1,910 scf CO_2/mmBtu.

2.2.3.5 Equation 2-5 may be used in lieu of the F or F_c factors specified in Section 2.2.3.4 to calculate an F factor (dscf/mmBtu) on a dry basis or an F_c factor (scf CO_2/mmBtu) on either a dry or wet basis. (Consult the Administrator for a method to calculate an F factor on a wet basis).

$$F = \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV} \times 10^6$$

(Eq. 2-5)

$$F_c = \frac{321 \times 10^3 (\%C)}{GCV}$$

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2.2.3.5.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176 (solid fuels) or computed from results using D1945-81 or D1946-90 (gaseous fuels) as applicable. (These three methods are incorporated by reference under § 75.9.)

2.2.3.5.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D2015-85 for solid fuels and D1826-88 for gaseous fuels, as applicable. (These two methods are incorporated by reference under § 72.9).

2.2.3.5.3 For affected units that combust both fossil and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

2.2.3.6 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by Section 2.3.4 shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \qquad F_c = \sum_{i=1}^{n} X_i (F_c)_i \qquad (Eq.2\text{-}6)$$

where

X_i = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).

F_i or $(F_c)_i$ = Applicable F or F_c factor for each fuel type determined in accordance with Section 2.2.3.4.

n = Number of fuels being combusted in combination.

2.2.4 Use the following equations to calculate the NO_x emission rate for each calendar quarter (Eq. 2-7) and the annual average emission rate (Eq. 2-8) in lb/mmBtu.

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n} \qquad (Eq.2\text{-}7)$$

where

E_q = Quarterly NO_x emission rate, lb/mmBtu.

E_i = Hourly NO_x emission rate, lb/mmBtu.

n = Number of hourly rates available in the preceding quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_q}{m} \qquad (Eq.2\text{-}8)$$

Where

E_a = Annual NO_x emission rate, lb/mmBtu.

E_q = Quarterly NO_x emission rate, lb/mmBtu.

m = Number of quarters for which E_q are available.

2.2.5 Round all NO_x emission rates to the nearest 0.001 lb/mmBtu.

2.3 CO_2. Use the following procedures to compute daily, quarterly, and annual CO_2 emissions in tons.

2.3.1 For an affected unit using a continuous emission monitoring system for the measurement of CO_2 emissions where CO_2 concentration is measured on a wet basis, use the

following equation to calculate hourly CO_2 emission rates (in lb/hr).

$$E_h = K\ C_h\ Q_h \qquad \text{(Eq. 2-9)}$$

where

E_h = Hourly emission rate of CO_2, lb/hr.

K = 1.140×10^{-7} for CO_2, (lbs/scf)/ppm.

C_h = Hourly average CO_2 concentration, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate, stack moisture basis, scfh.

Where CO_2 concentration is measured on a dry basis, use Equation 2-2 above to calculate the hourly CO_2 emission rate (in lb/hr) with a K-value of 1.14×10^{-7} (lb/scf)/ppm.

2.3.2 For an affected unit using a continuous emission monitoring system for the measurement of CO_2 emissions, use the following equation to calculate total CO_2 emissions for each calendar quarter in proportion to the recorded hourly CO_2 emissions.

$$E_{CO_2} = E_R \times \frac{H_U}{H_R} \qquad \text{(Eq. 2-10)}$$

where

E_{CO_2} = Total emissions of CO_2 for calendar quarter, tons.

E_R = Total emissions of CO_2 recorded by the CO_2 continuous emission monitoring system for calendar quarter, tons.

H_U = Total unit operating hours for calendar quarter, hr.

H_R = Total unit operating hours for which the CO_2 continuous emission monitoring system recorded data for calendar quarter, hr.

2.3.3 For an affected unit estimating CO_2 emissions in lieu of continuous monitoring, use the following equation to calculate daily CO_2 emission rates from fuel combustion (in tons/day).

$$W_{CO_2} = \frac{[MW_C + MW_{O_2}] \times W_C}{MW_C} / 2{,}000 \qquad \text{(Eq. 2-11)}$$

where

W_{CO_2} = CO_2 emitted from combustion, tons/day.

MW_C = Molecular weight of carbon (12.0).

MW_{O_2} = Molecular weight of oxygen (32.0)

W_C = Carbon burned, lb/day, determined using fuel analysis by ASTM D3178-(89) for coal; or determined by the percentage of carbon in oil from the ultimate analysis of oil, or computed based upon ASTM D3238-(85) and either ASTM D2502-(87) or ASTM D2503-(82) for oil; or computed based on ASTM D1945-(81) or ASTM D1946-(90) for gas; and fuel feed rates from company records for all fuels.

Sum the daily CO_2 emissions to obtain total CO_2 emissions for each calendar quarter and annual CO_2 emissions.

2.3.4 If the affected unit is equipped with a wet limestone flue gas desulfurization system, a fluidized bed with limestone as the sorbent material, or other emission control system that generates CO_2, use the following equation to calculate daily CO_2 emissions from the emission control system (in tons/day).

$$SE_{CO2} = W_{CaCO3} \times F_u \times [MW_{CO2}/MW_{CaCO3}] \quad \text{(Eq. 2-12)}$$

where

SE_{CO2} = CO_2 emitted from sorbent, tons/day.

W_{CaCO3} = $CaCO_3$ used, tons/day.

F_u = Sorbent utilization factor, 1.07 (the calcium to sulfur stoichiometric ratio). A value of 1.07 is used unless a different factor is calculated by the emissions control vendor or the owner or operator based on operational parametric conditions, and approved by the Administrator.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_{CaCO3} = Molecular weight of calcium carbonate (100).

2.3.5 For an affected unit equipped with an emissions control system that generates CO_2, use the following equation to obtain total daily CO_2 emissions (in tons/day) by adding the estimates of daily CO_2 emissions from fuel combustion and from the sorbent.

$$W_t = W_{CO2} + SE_{CO2} \quad \text{(Eq. 2-13)}$$

where

W_t = Estimated total CO_2 emissions, tons/day.

W_{CO2} = CO_2 emitted from fuel combustion, tons/day.

SE_{CO2} = CO_2 emitted from sorbent, tons/day.

Sum the daily CO_2 emissions to obtain total CO_2 emissions for each calendar quarter and annual CO_2 emissions.

2.4 Heat Input. Use the following procedures to compute heat input to an affected unit (in mmBtu).

2.4.1 Calculate and record heat input to an affected unit from any fuel other than natural gas on an hourly basis and from natural gas for each shipment delivered.

2.4.2 For an affected unit that has a flow monitor and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input (in mmBtu).

2.4.2.1 For CO_2 diluent monitors that measure CO_2 concentration on a wet basis, use the following equation:

$$HI = Q_w \times (1/F_c) \times (\%CO_{2w}/100) \qquad \text{(Eq. 2-14)}$$

where

HI = Hourly heat input, mmBtu.

Q_w = Hourly volumetric flow rate, wet basis, scfh.

F_c = Carbon-based F-factor, listed in Section 2.2.3.4 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$ = Hourly concentration of CO_2, percent wet basis.

2.4.2.2 For CO_2 diluent monitors that measure CO_2 concentration on a dry basis, use the following equation:

$$HI = Q_w \times (1-B_{ws})/F_c \times (\%CO_{2d}/100) \qquad \text{(Eq. 2-15)}$$

where

HI = Hourly heat input, mmBtu.

Q_w = Hourly volumetric flow rate, wet basis, scfh.

F_c = Carbon-based F-factor, listed above in 2.2.3.4 of this Appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2, percent dry basis.

B_{wa} = Moisture fraction of gas in the stack.

2.4.2.3 For O_2 diluent monitors that measure O_2 concentration on a set basis, use the following equation:

$$HI = Q_w \times (1/F_d) \times [20.9(1-B_{ws}) - \%O_{2w}] /20.9 \qquad \text{(Eq. 2-16)}$$

where

HI = Hourly heat input, mmBtu.

Q_w = Hourly volumetric flow rate, wet basis, scfh.

F_d = Dry basis F-factor, listed above in 2.2.3.4 of this Appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$ = Hourly concentration of O_2, percent wet basis.

B_{ws} = Moisture fraction of the stack gas.

2.4.2.4 For O_2 diluent monitors that measure O_2 concentration on a dry basis, use the following equation.

$$HI = [Q_w \times (1-B_{ws})/F_d] \times [(20.9-\%O_{2d})/20.9] \quad \text{(Eq. 2-17)}$$

where

HI = Hourly heat input, mmBtu.

Q_w = Hourly volumetric flow, wet basis, scf.

F_d = Dry basis F-factor, listed above in 2.2.3.4 of this appendix for each fuel, dscf/mmBtu.

B_{ws} = Moisture fraction of the stack gas.

$\%O_{2d}$ = Hourly concentration of O_2, percent dry basis.

2.4.3 Use the procedures specified in § 75.13(e) of this part to provide substitute data whenever a valid hour of flow data has not been obtained and recorded.

2.4.4 Whenever a valid hour of diluent (O_2 or CO_2) concentration has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded diluent gas (O_2 or CO_2) percentage concentration for the hour immediately before and the hour immediately following the missing data period.

2.4.5 For an affected unit that does not have a flow monitor and is using the procedures specified in Appendix D

of this part to monitor SO_2 emissions, use the following procedures to calculate hourly heat input in mmBtu.

2.4.5.1 Use the following equation to calculate hourly heat input when the unit is combusting oil.

$$HI_o = M_o \times GCV_o/1,000,000 \qquad \text{(Eq. 2-18)}$$

where

HI_o = Hourly heat input from oil, mmBtu.

M_o = Mass of oil consumed per hour, as determined using procedures in Appendix D of this part, i lb, tons, or kg.

GCV_o = Gross calorific value of oil, as measured daily by ASTM D240-87 or D2382-88, Btu/unit mass.

2.4.5.2 Use the following equation to calculate the heat input from each shipment of natural gas.

$$HI_g = (Q_g \times GCV_g)/1,000,000 \qquad \text{(Eq. 2-19)}$$

where

HI_g = Heat input of shipment of natural gas, mmBtu.

Q_g = Flow or amount of natural gas in shipment, scf.

GCV_g = Gross calorific value of natural gas, as measured for the shipment by ASTM D1826-88, Btu/scf.

PART 77-EXCESS EMISSIONS

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APPENDIX A TO PART 77—EXCESS EMISSIONS OFFSET PLAN FORMS
APPENDIX B TO PART 77—METHOD FOR ADJUSTING EXCESS EMISSIONS PENALTY RATE
APPENDIX C TO PART 77—LOCK BOX ADDRESSESS

AUTHORITY: 42 U.S.C. 7651

§ 77.0 Applicability.

(a) *General.* This part sets forth the Acid Rain excess emissions offset planning and offset penalty requirements pursuant to Section 411 of the Clean Air Act, 42 U.S.C. § 7401, et seq, as amended by Pub. L. 101-549 (November 15, 1990) (the Act). These requirements shall apply to the affected units and affected sources, and to the owners, operators, and designated representative of each affected unit or source under the Acid Rain program, as specified in 40 CFR 72.7 and 72.21.

(b) *Requirements and Prohibitions of Designated Representatives, Owners, and Operators.* Whenever any standard, requirement, or prohibition in this part or in 40 CFR Parts 70-78 applies to an affected unit or an affected source, or to the designated representative of an affected unit or affected source, the standard, requirement, or prohibition shall also apply to and be binding on each and every owner and operator of the affected unit or source (as applicable), each of whom shall be liable for any violation of such standard, requirement, or prohibition.

(c) Nothing in this part shall limit or otherwise affect the application of Sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended.

§ 77.1 Definitions.

For purposes of this part, the terms shall have the same meaning as that given in the Act, in 40 CFR Parts 72-78, and in this section, as follows:

Acid Rain compliance option means one of the following methods of compliance used by an affected unit under this part as described in a compliance plan submitted and approved in accordance with Subpart D of this part:

(1) Standard sulfur dioxide compliance method: having total emissions in any calendar year that are not greater than the allowances held, as of the allowance transfer deadline, in the unit's compliance subaccount for that year in accordance with a plan submitted and approved under § 72.40(b);

(2) Standard nitrogen oxides compliance method: emitting nitrogen oxides from an affected unit during a calendar year in an amount not greater than allowed by the applicable emissions limitation for the unit, pursuant to 40 CFR Part 76, in accordance with a plan submitted and approved under § 72.40(b);

(3) Compliance with a substitution plan submitted and approved in accordance with § 72.41;

(4) Compliance with a Phase I extension plan submitted and approved in accordance with § 72.42;

(5) Compliance with a reduced utilization plan submitted and approved in accordance with § 72.43;

(6) Compliance with a repowering extension plan submitted and approved in accordance with § 72.44;

(7) Compliance with a nitrogen oxides emissions averaging plan submitted and approved in accordance with § 72.46;

(8) Compliance with a nitrogen oxides alternative emissions limitation plan submitted and approved in accordance with § 72.47;

(9) Compliance with a nitrogen oxides compliance deadline extension plan submitted and approved in accordance with § 72.48;

(10) Compliance with a new unit plan submitted and approved in accordance with § 72.45;

(11) Compliance with an opt-in plan submitted and approved in accordance with § 72.49; or

(12) Compliance with a common-stack plan submitted and approved in accordance with § 72.50.

Acid Rain permit or permit means a permit, or the Acid Rain portion of a permit under 40 CFR Parts 70 or 71, including an approved compliance plan, issued by the Administrator or other permitting authority pursuant to this part and 40 CFR Parts 73-78 after completion of all administrative review.

Acid Rain program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to Title IV of the Act under 40 CFR Parts 72-78.

Act means the Clean Air Act, 42 U.S.C. § 7401, et seq., as amended by Pub. L. No. 101-549 (November 15, 1990).

Administrative permit amendment means a revision of an Acid Rain permit pursuant to § 72.303.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Affected source means a source that includes one or more affected units.

Affected unit means a unit, or a source that opts-in under 40 CFR Part 74, that is subject to any emission reduction requirement or limitation under the Acid Rain program.

Allowance means an authorization, allocated by the Administrator under the Acid Rain program to emit, during or after a specified calendar year, up to one ton of sulfur dioxide.

Allowance Tracking System means the system by which the Administrator issues, records, and tracks allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, which is the last day on which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Approved compliance plan means a compliance plan, and any revision thereto, that has been approved as part of an Acid Rain permit by the Administrator or the permitting authority in accordance with this part.

Calendar year means January 1 through December 31, inclusive.

Certificate of representation means the completed and signed submission, using the standard form required by § 72.20, for certifying the appointment of a designated representative for an affected source, an affected unit, or a group of identified affected units.

Compensating unit means a unit that is not otherwise an affected unit during Phase I, which is designated as an affected unit during Phase I for the purposes of providing electrical generation to make up for reduced utilization at one or more other Phase I affected units, in accordance with § 72.43.

Compliance plan means the permit document, submitted in accordance with Subparts C and D of this part, certifying that the source will comply with all applicable requirements under the Acid Rain program and including a schedule of compliance and description of the Acid Rain compliance options by which each unit at the source will meet the applicable emissions limitation requirements of Title IV of the Act.

Compliance subaccount means an affected unit's allowance tracking system subaccount in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances for the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances for the preceding calendar year.

Consumer Price Index (CPI) means the United States government's primary indicator of the monetary inflation rate as published monthly by the U.S. Department of Labor, Bureau of Labor Statistics Consumer Price Index Branch, in the CPI Detailed Report and in the Monthly Labor Review. For purposes of this part, the Administrator will use the Consumer Price Index for all urban consumers for the US City Average, for all Items on the Official Reference Base (CPI-U), or if such index is no longer published, such other index as the Administrator in his discretion determines meets the requirements of the Clean Air Act Amendments of 1990. For the purposes of this part, the CPI-U is based on the twelve month period ending August 31.

Designated representative means the natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with 40 CFR Part 72, Subpart B, to represent and legally bind each owner and operator, as a matter of Federal law, in all matters pertaining to the Acid Rain program. Except in § 72.20(c), the term designated representative shall also mean any natural person authorized in accordance with § 72.20(c) of 40 CFR Part 72 as an alternate designated representative. Whenever the term responsible official is used in 40 CFR Part 70 or 71 or in a State operating permit program approved pursuant to Title V of the Act and 40 CFR Part 70, it shall be deemed to refer to the designated representative as defined here in so far as Acid Rain program actions, standards, requirements, or prohibitions are concerned.

Determination of completeness means a finding by a permitting authority in accordance § 72.72 or § 70.5(c) with regard to an Acid Rain permit program application specifying that the application contains all the information needed to begin processing the application, consistent with the criteria in Subpart G of this part.

Emissions means the quantity of an air pollutant emitted from an affected unit, as measured, recorded, and reported to the Administrator or a State by the designated representative and determined by the Administrator, in accordance with the emissions monitoring requirements of 40 CFR Part 75.

Emissions limitation means

(1) For the purposes of sulfur dioxide emissions, the tonnage equivalent of:

(a) The allowances allocated by the Administrator to a unit for use in a calendar year, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of Title IV of the Act and the Acid Rain program, or with the Acid Rain permit issued by the permitting authority;

(b) As amended by allowance transfers to or from the compliance subaccount for that unit.

(2) For purposes of nitrogen oxides emissions, the limitation established pursuant 40 CFR Part 76, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of Title IV of the Act and the Acid Rain program, or with an Acid Rain permit issued by the permitting authority.

EPA means the United State Environmental Protection Agency or, for purposes of 40 CFR Part 73, any person who by delegation or contract is managing and conducting the auctions and direct sales provided in Part 73 on behalf of EPA.

Excess emissions means:

(1) Any tonnage emissions of sulfur dioxide by an affected unit during a calendar year that exceeds the sulfur dioxide allowances recorded in the unit's compliance subaccount; and

(2) Any tonnage emissions of nitrogen oxide by an affected unit during a calendar year that exceed the emissions limitation applicable to the affected unit as specified in 40 CFR Part 76 and the affected unit's permit.

Offset period means the calendar year, or such other period, as determined by the Administrator in accordance with 40 CFR Part 77, following a calendar year in which an affected unit had excess emissions, during which excess emissions offsets are required to be achieved.

Offset plan means a plan submitted and approved pursuant to 40 CFR Part 77 for offsetting excess emissions that have occurred at an affected unit in any calendar year.

Owner means any of the following persons, each of which is required to be identified in a certificate of representation under 40 CFR Part 72, Subpart B:

(1) Any holder of any portion of the legal or equitable title to an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any utility or industrial customer that purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in Section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or operator means any person who is an owner or who operates, controls, or supervises an affected unit or a source of which an affected unit is a part, and shall include but not be limited to any holding company, operating company, utility system, designated representative, or plant manager of an affected unit or affected source.

Permitting authority means either of the following:

(1) The Administrator in the case of EPA implementation of the Acid Rain permit program; or

(2) The State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under Title IV and V of the Act and 40 CFR Part 70 and Part 72, Subpart I.

Person means an individual corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

Phase I means the Acid Rain program compliance period beginning January 1, 1995 and ending December 31, 1999.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Act, including any applicable Acid Rain permit requirement.

Serial number means the unique identification number assigned to each allowance by EPA, pursuant to § 73.34(c).

Source means any institutional, commercial, or industrial structure, installation, plant, or building that emits or has the potential to emit any air pollutant regulated under Title IV of the Act. For purposes of Section 502(c) of the Act, a source, including a source with multiple units, shall be considered a single facility.

State means one of the 48 contiguous States and the District of Columbia., and includes all non-federal authorities, including local agencies, interstate associations, tribal authorities, and state-wide agencies with approved permit programs under 40 CFR Part 70. The term State also encompasses those Native American governing bodies that the Administrator has determined, pursuant to Section 301(d) of the Act, to treat as States.

Substitution unit means an affected unit that is listed in 40 CFR Part 72, Appendix B and is designated as a Phase I affected unit in a substitution plan under § 72.41.

Sulfur dioxide emissions limitation requirements means the limitation specified for an affected unit in Sections 403, 404, or 405 of the Act or in the unit's permit.

Ton or Tonnage means any ton or fraction of a ton of emissions. For the purpose of determining compliance with the allowance requirements of the Acid Rain program, any fraction of a ton shall be deemed to equal one ton and require one allowance.

Unit means a fossil-fuel fired combustion device that serves a generator.

Utilization means the heat input for a unit.

§ 77.2 Sulfur dioxide excess emissions offset planning.

(a) *Applicability.* The owners and operators of any affected unit that emits sulfur dioxide in any calendar year in an amount that exceeds the affected unit's Acid Rain program sulfur dioxide emissions limitation requirement for that year, based on the number of allowances held in the unit's Allowance Tracking System account as provided in 40 CFR Part 73, shall compensate for such excess emissions during the offset period specified by the Administrator in accordance with this section, by an amount equal to or in excess of the tons of excess emissions that occurred during that year.

(b) *Deadline.* Not later than 60 days after the end of any calendar year during which excess emissions of sulfur dioxide occurred at an affected unit, the designated representative for the affected unit shall submit a proposed excess emissions offset plan to the Administrator, to the EPA Regional Office for the State where the source is located, to the permitting authority for the State in which the source is located, and to each State located within a 50-mile radius of an affected source. All submissions shall be made as provided in 40 CFR 72.4.

(c) *Multi-Unit Plans - General Rule.* Except as provided in paragraph (d) of this section, the designated representative for two or more affected units with excess emissions shall submit a separate excess emissions offset plan for each affected unit with

excess emissions. The multi-unit plan shall consist of one SF# 772 for each unit in the plan.

(d) *Multi-Unit Plans - Exception.* The designated representative for two or more affected units with excess emissions governed by a common stack plan approved pursuant to 40 CFR 72.50, shall submit one excess emissions offset plan for those affected units with excess emissions.

(e) *Contents of Plan.* Each proposed excess emissions offset plan submitted pursuant to this part shall be submitted on SF# 772 in Appendix A of this part, and shall:

(1) Be signed by the designated representative of the unit(s) governed by the plan;

(2) Specify the name, title, phone number, facsimile number, mailing address, and Acid Rain program identification number of the designated representative for the affected unit with excess emissions;

(3) Specify the name, location, mailing address, and Acid Rain program identification number of the affected unit with excess emissions;

(4) Include a certification that the affected unit had excess emissions for the calendar year:

(i) Specifying the number of tons of excess emissions emitted by the affected unit during the calendar year;

(ii) Describing how and why the excess emissions occurred; and

(iii) Describing any corrective actions that were taken by the owners and operators to prevent or minimize the extent of the excess emissions;

(5) Specify the proposed offset methodology, and a schedule for achieving the offsets, as follows:

(i) Each offset plan shall include a description of the measures that are proposed to be taken to offset the excess emissions including:

(A) The number of allowances required to be deducted from the unit's Allowance Tracking System account to offset the excess emissions; and

(B) A schedule of compliance with appropriate increments of progress for reducing emissions of sulfur dioxide; for deducting allowances to offset the excess emissions from the Allowance Tracking System account of the unit or units responsible under the plan for achieving the offsets, including the serial number of the allowances and specification of when the deduction should occur; for obtaining additional allowances necessary; and for taking corrective actions.

(ii) Each offset plan shall include a certification that no allowance will be transferred during the offset period from the Allowance Tracking System account for the affected unit responsible for the offsets that might cause any further excess emissions at the unit.

(iii) If the designated representative proposes to offset excess emissions using the standard offset method (i.e., deducting the entire amount of allowances equal to the tonnage of excess emissions from the unit's Allowance Tracking System

compliance subaccount for the following calendar year), the offset plan shall so state.

(iv)(A) If the designated representative proposes to offset excess emissions occurring during Phase I by relying on one or more Acid Rain compliance options authorized under 40 CFR Part 72, Subpart D (e.g., 40 CFR 72.43, reducing utilization or shutting down the affected unit responsible for the excess emissions and offsets), the offset plan shall include the appropriate standard form for the Acid Rain compliance option plan chosen, as provided in 40 CFR Part 72, Subpart D.

(B) Each offset plan shall include a demonstration that the reductions achieved by relying on one or more Acid Rain compliance options of 40 CFR Part 72, Subpart D is equal to the reductions required by a standard excess emissions offset plan, in accordance with paragraph (e)(5)(iii) of this section.

(v) If the compliance option chosen involves multiple units, the offset plan shall include:

(A) A designation of any compensating or substitution unit(s);

(B) A schedule specifying deadlines for, e.g., reducing utilization of the unit responsible for the excess emissions, and for the load shifting; and

(C) A certificate of representation establishing each designated representative's authority with regard to each unit covered by the multi-unit plan.

(vi) If the designated representative proposes to offset excess emissions by installing a technological means of pollution control (e.g., high efficiency scrubber, repowering or other clean coal technology), the excess emissions offset plan shall:

(A) Specify increments of progress for installing and commencing operation of equipment; and

(B) Include a showing of technical adequacy.

(vii) Each offset plan shall include a demonstration that the schedule for achieving the offsets is as expeditious as practicable, taking into account electric reliability.

(6) List and describe the provisions of the affected unit's permit and approved compliance plan that would be revised by the proposed offset plan if approved;

(7) Include a schedule for the submission of progress reports, as follows:

(i) The offset plan shall require that the designated representative submit quarterly progress reports, submitted with the reports due under 40 CFR 72.401(b), commencing with the first calendar quarter following the date in which an excess emissions offset plan is due under subsection (b), until the quarter in which the offsets are achieved, due within 30 days after the end of the previous calendar quarter, which shall include:

(A) A description of the work accomplished;

(B) A demonstration that interim milestones were achieved;

(C) A summary of remaining work to be performed; and

(D) Proposed adjustments, if any, to the schedule.

(ii) The offset plan shall require that the designated representative submit a final report and supporting documentation

with the annual report required by 40 CFR Parts 72, 73, and 75, for the year during which all required offsets are achieved in full, which shall include:

(A) A description of the work performed in accordance with the offset plan;

(B) The date that the offsets were achieved;

(C) The number of tons of offsets achieved; and

(D) Documentation that the offsets were achieved.

(iii) The offset plan shall require that each report be signed by the designated representative, be submitted pursuant to this section, and contain the following certification:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

(f) A designated representative may identify by serial number the allowances to be deducted from the compliance subaccount for purposed of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made by submission of the Compliance Deduction Form, provided in 40 CFR Part 73 with the offset plan, or by electronic methods as the Administrator shall prescribe in the future.

§ 77.3 Administrator's action on offset plans.

(a) *Determination of Completeness.* (1) A designated representative shall be deemed to have submitted a complete excess emissions offset plan if the plan includes all applicable information required in § 77.2(e).

(2) No offset plan shall be considered complete unless it is submitted on standard forms in Appendix A of this part or through the Acid Rain Program Electronic Permitting Program System, as established by the Administrator.

(3) The Administrator shall determine whether the offset plan submitted by the source is complete within 30 days of receipt by the U.S. EPA Regional Office for the Region in which the source is located. The offset plan shall be deemed to be complete by operation of law if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt.

(b) *Effect of a Determination of Completeness.* (1) If a designated representative has submitted a timely and complete excess emissions offset plan on a timely basis, but the Administrator has not yet made a decision on such plan, each affected unit covered by the offset plan shall be deemed to be in compliance with the prohibition in paragraph (m)(1)(i) of this section.

(2) A complete offset plan shall be binding on the designated representative, owners, and operators of the affected units at the source, and shall be enforceable against the affected source until the Administrator makes a decision on the plan.

(c) *Supplemental Information.* (1) The Administrator may require, by issuing a notice for supplemental information, submission of any additional information necessary to issue an offset plan that complies with all the requirements of this part and 40 CFR Parts 70-76 and 78.

(2)(i) The designated representative shall submit the required information within 30 days of receiving a notice for supplemental information from the Administrator unless the Administrator allows for additional time in writing as reasonable for the designated representative to collect and submit the required information, not to exceed 4 months from the date the excess emissions offset plan was first submitted to the Administrator.

(ii) A failure to submit the supplemental information within the required time period shall result in a denial of the proposed offset plan. Such denial shall be considered a decision of the Administrator for purposes of any appeal pursuant to 40 CFR Part 72, Subpart H.

(d) *Proposed Excess Emissions Offset Plan.* (1) After the Administrator receives all supplemental information requested by notice, the Administrator shall issue a proposed excess emissions offset plan for the affected source.

(2) The proposed offset plan shall be based on the information submitted by the designated representative for the affected source and such other relevant information.

(3) The Administrator shall develop an administrative record for the proposed offset plan, and such record shall include:

(i) Documents submitted by the source under § 77.2(e); and

(ii) Other documents relied on by the Administrator to develop the proposed offset plan, including any records of discussions or conferences with the source or other interested persons regarding the offset plan.

(4) The Administrator shall include in the administrative record for any offset decision:

(i) The offset decision;

(ii) The administrative record for the proposed offset plan;

(iii) Copies of all written public comments submitted on the proposed offset plan;

(iv) The record of any public hearing on the proposed offset plan;

(v) Any response to public comments submitted on the proposed offset plan as required by subsection (h) of this section, including any documents cited in the response; and

(vi) Any data, reports, or other materials submitted to, or generated by, the Administrator, during the public comment period that were considered by the Administrator in making a decision.

(5) The Administrator is required to act on a proposed excess emissions offset plan within six months of receipt.

(e) *Opportunities for Public Comment on Proposed Offset Plans.*

(1) *Generally.* (i) The Administrator shall give public notice of the following:

(A) Any proposed offset plan and its availability for public review and comment;

(B) Opportunity to request a public hearing on a proposed offset plan pursuant to subsection (g) of this section, and

(C) Any scheduled hearing granted pursuant to subsection (g) of this section.

(ii) Any public notice of a proposed offset plan given under this part may be for one or more proposed offset plans.

(2) *Timing.* Public notice under this part shall provide for:

(i) A 30-day public comment period, beginning from the date of publication of the notice of a proposed offset plan; and

(ii) An opportunity to request a public hearing on the proposed offset plan, including a scheduled date and place for the hearing if requested, to occur not earlier than 15 days after the notice is given.

(3) *Methods.* The Administrator shall give the public notice of the proposed offset plan required by this section, as follows:

(i) Actual notice shall be given to the following persons (except to the extent any such person has waived his or her right to receive such notice for any class or category of an offset plan action);

(A) The designated representative;

(B) The State or local air pollution agency and the State ratemaking authority (if any) with jurisdiction over the affected source governed by the proposed offset plan;

(C) In accordance with Title V of the Act, the State or local air pollution agency for any contiguous State whose air quality may be affected by the affected source that is the subject of the proposed offset plan, or for any State located within a 50-mile radius of the affected source; and

(ii) Notice by publication in the FEDERAL REGISTER and by advertisement in the area affected by the proposed offset plan.

(4) *Contents.* All public notices issued under this part shall contain the following information:

(i) Name, and address, of the EPA office processing the offset plan for which the notice is being given;

(ii) Name, address, telephone and facsimile number of the designated representative for the affected source;

(iii) Identification of each affected unit at the source covered by the proposed offset plan as follows; name (plant, unit), address;

(iv) A brief description of the action proposed to be taken; including, for proposed offset plans:

(A) The amount of emissions that must be offset in the source's offset plan;

(B) Any alternative methods of compliance which are proposed to be approved to meet the required offset; and

(C) The period of time during which the offset is proposed to occur, if greater than one year.

(v) The address and office hours of a public location where the offset plan administrative record provided under paragraph (d)(3) of this section is available for public inspection; and a statement that all information submitted by the designated representative and not protected as confidential pursuant to Section 114(c) of the Act is available for public inspections as part of the offset plan administrative record;

(vi) Name, address, telephone and facsimile number of the EPA office from whom interested persons may obtain further information;

(vii) A brief description of the public comment procedures, including:

(A) Explanation of the purpose of the public comment opportunity;

(B) The time allowed for public comments;

(C) Where public comments should be sent;

(D) Required formats and contents for public comment;

(E) The location, date, time, and procedures of any scheduled public hearing; and

(F) Any other procedures by which the public may participate.

(5) *Extensions and Reopenings of the Public Comment Period.* On the Administrator's own motion, or on the request of any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where it reasonably appears that doing so will expedite the decision-making process. Notice of any such extension or reopening shall be give pursuant to this section.

(f) *Public comments.*

(1) *General.* (i) Any person may submit comments on an offset plan.

(ii) Comments shall be submitted during the public comment period. Comments received after the public comment period has closed will not be considered.

(iii) Comments shall be submitted in duplicate.

(iv) The submission shall clearly indicate the proposed offset plan to which the comments apply.

(v) The submission shall clearly indicate the name of the commenter, and where appropriate, the affiliation of the commenter.

(2) *Contents.* Comments may be made on any aspect of the proposed offset plan or proposed offset plan modification.

(i) Comments will be considered when making a decision on the offset plan.

(ii) Comments will not be considered if they concern the contents of the source's permit. Comments specifically concerning the issuance of the proposed offset plan, such as requests for a public hearing on such offset plan, will be considered.

(iii) Commenters who do not wish to raise issues on the proposed offset plan, but who wish to be notified of any subsequent offset plan actions, may so indicate during this public comment period or at any other time.

(g) *Opportunity for Public Hearing.* (1) During the public comment period provided under subsection (e) of this section, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the nature of the issues proposed to be raised in the hearing.

(2) The Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that:

(i) A request for such has been made that raises significant issues affecting the terms and conditions of the offset plan and such hearing would contribute to the decision on the offset plan; or

(ii) A hearing might clarify one or more issues raised by the proposed offset plan.

(3) Public notice of the scheduling of a public hearing shall be given as specified in subsection (e) of this section.

(4) During a public hearing under this section, any person may submit oral or written comments concerning the proposed offset plan. The Administrator may set reasonable limits on the time allowed for oral statements, shall require the submission of written summaries of each oral statement, and may extend the public comment period by so stating during the hearing.

(5) The Administrator shall assure that a record is made of the hearing, which shall be made part of the offset administrative record provided under paragraph (d)(3) of this section.

(h) *Response to Comments.* (1) The Administrator shall consider comments received during the public comment period and shall respond in writing to such comments when issuing the offset decision.

(2) The response to comments shall:

(i) Identify any offset plan provision which has been changed in the offset decision in response to comments made, and the reasons for the change; and

(ii) Briefly describe and respond to comments on the proposed offset plan.

(3) Any documents cited in the response to comments shall be included in the administrative record, or their location shall be cited, if readily obtainable.

(i) *Issuance and Effective Date of Excess Emissions Offset Plans.* (1) After the close of the public comment period, the Administrator shall:

(i) Act on the proposed excess emissions offset plan by either:

(A) Approving the excess emissions offset plan as submitted,

(B) Approving the excess emissions offset plan, in whole or in part, with any appropriate revisions;

(C) Approving the excess emissions offset plan, with expeditious and enforceable deadlines included in the plan for the conditions to be met not later than the end of the year; or

(D) Disapproving the excess emissions offset plan and either:

(1) Deducting allowances, or

(2) Issuing such order as is necessary to achieve the offsets.

(ii) Specify as part of the action an excess emissions offset period for achieving, in full, the emissions reductions required by the plan.

(iii) Give actual notice of the decision to the designated representative for the affected source, and to any persons who submitted comments during the public comment period or who are entitled to actual notice under paragraph (e)(3) of this section. The Administrator shall also give notice of the decision in the FEDERAL REGISTER.

(2) Any offset decision shall be issued and become final agency action 60 days after notice of the offset decision is published in the FEDERAL REGISTER, unless an appeal is filed pursuant to 40 CFR Part 72, Subpart H.

(3) The term of every offset plan shall be for the remainder of the year in which the source is required to have an offset plan, or for such larger period as is approved in the offset plan.

(j) Upon approval of the proposed offset plan by the Administrator, the offset plan shall be deemed a condition of the operating permit for the unit without further review or revision of the permit.

(k) *Deduction of Allowances.* The Administrator shall deduct allowances, in accordance with the approved excess emissions offset plan, equal to the tons of excess emissions.

(1) The allowances shall be deducted in the year following the year when the excess emissions occurred, unless the Administrator approves a longer offset period.

(2) If an approvable offset plan is not timely submitted in accordance with this section, the Administrator shall deduct allowances from the annual allocations that would otherwise be made to the unit which had the excess emissions from the unit's Allowance Tracking System account in the year following the year in which excess emissions occurred.

(3) The Administrator may make a determination that allowance deductions occur over a specified period greater than 1 year provided the designated representative for the unit or units makes a showing, to the Administrator's satisfaction, that deducting the entire amount of the allowances required to offset the excess emissions during the following calendar year will interfere with electric reliability.

(l) *Binding Effect of Offset Plan.* (1) Upon the issuance of a determination of completeness by the Administrator as provided in subsection (a) of this section, the proposed offset plan shall be binding on the designated representatives and the owners and operators of the unit(s) governed by the plan and shall temporarily supersede any inconsistent provisions of the permit and approved compliance plan for the affected source. The proposed offset plan shall, thereafter, remain in effect until the Administrator acts on the proposed excess emissions offset plan as provided in this section.

(2) Upon issuance of a determination of completeness by the Administrator as provided in subsection (a) of this section, the plan shall be deemed to be incorporated into the permit without

further review or revision as an administrative permit amendment in accordance with 40 CFR 72.303. The Administrator's action on the plan shall be deemed a permitting decision, shall also be incorporated into the permit as an administrative amendment, and shall be subject to the appeals provisions of 40 CFR Part 72, Subpart H and Section 307 of the Act.

(m) *Prohibitions.* It shall be a violation of this part and of the Act for the designated representative of an affected unit liable for excess emissions offsets under this part and Section 411 of the Act, to fail to:

(1) Submit:

(i) A complete and approvable proposed excess emissions offset plan in a timely manner; and

(ii) Any progress reports required by this part, in a timely manner;

(2) Comply with the terms of a proposed or approved excess emissions offset plan; or

(3) Otherwise offset excess emissions as required by this part.

(n) Any failure to comply with any requirement of this part shall be a separate enforceable violation of the Act.

(o) Each day after the 60-day deadline for submitting the excess emissions offset plan, or after a reporting deadline, that the designated representative for the affected unit fails to submit a complete excess emissions offset plan shall be deemed a separately enforceable violation of the Act.

§ 77.4 Excess emissions penalties.

(a) In the event excess emissions of sulfur dioxide or nitrogen oxides occur at an affected unit during any calendar year, the designated representative of the affected unit shall submit, without demand, payment of an excess emissions penalty in accordance with this section. The designated representative, and the owners and operators of the unit with excess emissions shall be held strictly liable for the obligation to automatically pay without delay any penalty due under this part. In the case of excess emissions such payment must be received no later than 60 days after the end of any calendar year during which excess emissions occurred at an affected unit, subject to the interest obligation accruing from January 1, 1991, specified in subsection (c).

(b)(1) The designated representative responsible for submitting the penalty shall be responsible for correctly calculating the penalty.

(2) The excess emissions penalty shall be determined using the following formula:

$$EEP = AEEPR \times Q$$

where:

EEP is the excess emissions penalty,

AEEPR is the adjusted excess emissions penalty rate determined in accordance with the method specified in Appendix B of this part, and

Q is the number of tons of excess emissions.

(3) Round EEP to the nearest dollar after completing the calculation in paragraph (b)(2) of this section.

(c) In the event an excess emissions penalty due under this part is not paid in a timely manner, in accordance with subsections (a) and (b) of this section, the total excess emissions penalty shall be calculated to include interest, accruing from January 1 until the date on which the penalty payment is submitted, as follows:

(1) The interest rate for delayed payment (i) shall be equal to the coupon issue yield equivalent (as determined by the Secretary of Treasury) of the average accepted auction price for the last auction of 52 week U.S. Treasury bills settled for the week immediately prior to January 1 of the year the penalty is due.

(2) The total penalty, with accrued interest shall be determined using the following formula:

(i) $$EEP_i = EEP \times (1 + i)^n$$

where:

EEP_i is the total excess emissions penalty with accrued interest;

EEP is the excess emissions penalty (as calculated in paragraph (b) of this section);

i is the interest rate, as calculated in accordance with paragraph (c)(1) of this section; and

n is the number of months subsequent to January 1 of the year that payment is due where the first day of each month shall increase the value of n (January 31, n=1; February 28/29, n=2; March 30, n=3).

(ii) Round EEP_i to the nearest dollar after completing the calculation in paragraph (c)(2)(i) of this section.

(d) Any excess emissions penalty shall be due and payable automatically without demand to the Administrator as follows:

(1) Payments of penalties less than $25,000 shall be made by cashier's or certified check, made payable to the U.S. Treasurer, and sent to the lock box for the EPA Regional Office for the State where the affected unit is located, at the address specified in Appendix C of this part; and

(2) Payments of penalties of $25,000 or more shall be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York, using SF# 774 in Appendix A of this part.

(3) A written confirmation of payment shall be sent to the Administrator, using SF# 774A in Appendix A of this part.

(e) It shall be a violation of the Act for the designated representative of an affected unit liable for penalty payments under this part to fail to:

(1) Correctly determine the penalty amount; or

(2) Pay the penalty as required by this part.

(f) Any failure of the designated representative of an affected unit liable for excess emissions penalties under this part to comply with any requirement of this section, including any failure to pay an excess emissions penalty, shall be deemed a separately enforceable violation of the Act.

(g) Any excess emissions penalty due and payable under this paragraph shall not affect the liability of the affected unit's designated representative, owner or operator, for any additional fine, penalty, or assessment for the same violation authorized under any other section of the Act.

(h) Excess emissions in any calendar year resulting directly from an order issued in that year pursuant to Section 110(f) of the Act, shall not be subject to the penalty payment requirements of this section; provided that the designated representative of any unit subject to such order shall advise the Administrator within 30 days of issuance of the order that the order will result in such excess.

§ 77.5 Other.

The addresses for submissions, Federal authority, State authority, signatory requirements, recordkeeping, availability of information, and computation of time are provided as follows:

(a) Addresses for Submissions. (1) All submissions required by this part that must be sent to U.S. Environmental Protection Agency headquarters shall be addressed to the Chief, Permits and Technologies Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

(2) All submissions required by this part that must be sent to EPA regional offices shall be addressed to the appropriate region as follows:

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont) -- Director, Air Pesticides and Toxics Management Division, U.S. Environmental Protection Agency,John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands) -- Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) -- Director, Air, Radiation and Toxics Management Division, U.S. Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee) -- Director, Air, Pesticides, and Toxics Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, N.E., Atlanta, Georgia 30365.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin) -- Director, Air and Radiation Division, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas) -- Director, Air, Pesticides, and Toxics Division, U.S. Environmental Protection Agency, 1445 Ross Avenue, Dallas, Texas 75202.

Region VII (Iowa, Kansas, Missouri, Nebraska) -- Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, Missouri 66101.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming) -- Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, Colorado 80295.

Region IX (Arizona, California, Guam, Hawaii, Nevada) -- Director, Air and Toxics Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94105.

Region X (Alaska, Idaho, Oregon, Washington) -- Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101.

(3) All submissions required by this part that must be sent to a State permitting authority with an approved permit program under this part and 40 CFR Part 70 shall be addressed to the applicable permitting authority as provided in 40 CFR Part 70, and to the following State air pollution agencies:

State of Alabama, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of California, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 614 H Street, N.W., Washington D.C. 20001.

State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.

State of Iowa, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of Maryland, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th floor, Lansing, Michigan 48926.

State of Minnesota, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of Mississippi, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of Missouri, Department of Natural Resources, P. O. Box 1368, Jefferson City, Missouri 65101.

State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of Nebraska, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.

State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of New Hampshire, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of New Jersey, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.

State of New Mexico, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of New York, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.

State of North Carolina, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

State of Ohio, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.

State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of Oregon, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.

Commonwealth of Pennsylvania, Department of Environmental Resources, 105 S. Second Street, P.O. Box 2357, Harrisburg, Pennsylvania 17120.

State of Rhode Island, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of Tennessee, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.

State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.

State of Washington, Department of Ecology, Olympia, Washington 98504.

State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.
State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

(4) For all submissions required by this part to be submitted to a State, an EPA Regional office, or EPA Headquarters, copies shall also be sent to the State, to the appropriate EPA Regional office, and to EPA Headquarters.

(b) *Federal Authority.* Under authority of Sections 114 and 301 of the Act, the Administrator reserves the right to:

(1) Secure information needed for the purpose of developing or implementing any standard, requirement, or prohibition under the Act, or 40 CFR Parts 70-76 and 78 or of determining whether any person is in violation of any standard, requirement, or prohibition of the Act, this part, or 40 CFR Parts 72-76 and 78;

(2) Make inspections, conduct tests, examine records, and require the designated representative, the owner, or the operator of an affected unit to submit information reasonably required for the purpose of developing or implementing any standard, requirement, or prohibition under this part, and 40 CFR Parts 72-76 and 78; and

(3) Call witnesses and compel the production of documents.

(c) *State Authority.* Consistent with Section 116 of the Act, the provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from adopting and enforcing any other air quality requirement applicable to an affected source or unit; *provided* that such requirement is not less stringent than, and does not alter any requirement applicable to such unit or source prescribed under this part; and *provided*, further, that such requirement if articulated in an operating permit, is expressed in a portion of the permit separate from the portion containing the Acid Rain program requirements. Nothing in this section shall authorize a State permitting authority to modify or alter any Acid Rain program requirement except as provided in Title IV and elsewhere in this part.

(d) *Signatory Requirements.* (1) All Acid Rain program submissions required to be made on behalf of affected sources and affected units pursuant to this part and 40 CFR Parts 70-76 and 78, including the submissions specified in 40 CFR 72.21, shall be made by the designated representative for the source's owners and operators by certified mail. In each submission, the designated representative shall sign and certify:

(i) That the procedure specified in the representation agreement, pursuant to 40 CFR 72.20, for obtaining the authorization of the owners and operators to take such action has been complied with; and

(ii) The following statement: I certify under penalty of law that I have personally examined, and am familiar with, the information submitted in this document and all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the

information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

(2) The permitting authority shall only act upon submissions that have been signed, certified and filed by the duly authorized designated representative for the affected units at the source.

(e) *Recordkeeping.* Records and reports required to be maintained, issued to any person or submitted to the Administrator, a State air pollution control agency, or a permitting authority pursuant to this part, shall be kept on file at the source for a period of 5 years. This period may be extended for cause at anytime prior to the end of the 5 years in writing by the Administrator or the permitting authority.

(f) *Availability of Information.* The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by 40 CFR Part 2.

(g) *Computation of Time.* (1) Any time period scheduled to begin on the occurrence of a date, act, or event shall begin on the day the act or event occurs.

(2) Any time period scheduled to begin before the occurrence of a date, act, or event shall be computed so that the period ends on the day before the act or event occurs.

(3) If the final day of any time period falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(4) Whenever a party or interested person has the right, or is required, to act within a prescribed period after service of notice or other document upon him or her by mail, 3 days shall be added to the prescribed time.

Appendix A to Part 77—Excess Emissions Offset Plan Forms

1. Excess Emissions Offset Planning Form 772

2. Excess Emissions Penalty Forms 774 and 774A

FORM 772

Excess Emissions Offset Planning

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

~~1200~~ 787

DRAFT 772
Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP Identification Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Excess Emissions Offset Planning

Follow Instructions for Form 772.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name	C. Year of Excess Emissions

D. Excess Sulfur Dioxide Emissions *(tons)*

☐ E. Attached is a description of reasons for the excess emissions and of corrective actions taken.

II. SULFUR DIOXIDE EXCESS EMISSIONS OFFSET PLAN

☐ A. This unit proposes to offset excess emissions by using the following methods:

- ☐ 1. Substitution Plan
- ☐ 2. Reduced Utilization Plan
- ☐ 3. Deducting Allowances
- ☐ 4. Installing pollution control technology

B. Attached are:

- ☐ 1. Proposed schedule of compliance for reducing Sulfur Dioxide emissions or obtaining additional allowances.
- ☐ 2. Demonstration that compliance options will achieve reductions.
- ☐ 3. A list of provisions of the current approved compliance plan for this unit that would be revised by the proposed offset plan.

III. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. **Sulfur Dioxide.** The Sulfur Dioxide emissions limitation during the offset period shall be as stated in the approved offset plan.
2. **Nitrogen Oxides.** The Nitrogen Oxides emissions limitations shall be as stated in the source permit for this unit.

B. Recordkeeping Requirements

The unit shall comply with the recordkeeping requirements in the permit for this unit.

C. Reporting/Compliance Certification Requirements

1. The Designated Representative shall submit quarterly progress reports, submitted with the reports due under Section 72.401(b), commencing with the first calendar quarter following the date on which an excess emission offset plan is due until the quarter in which the offsets are achieved. Each report shall be due within 30 days after the end of the previous calendar quarter, and shall contain all information required by 40 CFR Section 77.2.
2. The Designated Representative shall submit a final report with the annual report required by 40 CFR Parts 72, 73, and 75 for the year during which all required offsets are achieved in full, and shall contain all information required by 40 CFR Section 77.2.

D. Prohibitions

1. It shall be a violation for an allowance to be transferred during the offset period from the Allowance Tracking System account for the affected unit responsible for the offsets that might cause further excess emissions at the unit.
2. It shall be a violation for the Designated Representative to fail to submit any plans or reports required under 40 CFR Section 77.2 in a timely manner, to fail to comply with the terms of an approved plan, or to otherwise fail to offset emissions as required by 40 CFR Part 77.2.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Received: _____
2. Date of Initial Review: _____ By: _____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: _____
3. Date of Final Approval: _____ By: _____
4. Date Notice Sent: _____ By: _____

Comments:

FORM #772
EXCESS EMISSIONS OFFSET PLANNING

INTRODUCTION

Clean Air Act Section 411(b) and the regulations implementing that section at 40 CFR §§77.2 and 77.3 require that any affected unit that emits sulfur dioxide in excess of the unit's emissions limitation or of the allowances held for the unit in a given year must offset the excess emissions by an equal tonnage amount in the following year. The Designated Representative is required to submit to the Permitting Authority a plan to achieve the required offsets within 60 days after the end of the year in which the excess emissions occurred

INSTRUCTIONS

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. UNIT IDENTIFICATION

A and B. Enter the unit Acid Rain Program Identification Number and the short name for the unit given in the Acid Rain permit application at Part I, Sections A and B.

C. Indicate the year in which excess emissions occurred for which you are submitting this proposed plan.

D. Enter the number of excess tons of emissions being reported on this form.

E. Indicate that you have attached a description of why the excess emissions occurred, (e.g., emissions reductions equipment failed to perform as expected, utilization was increased, etc.), and of the corrective action taken during the year of the excess emissions to prevent or minimize the excess.

II. SULFUR DIOXIDE EXCESS EMISSIONS OFFSET PLAN

A. Proposal to Offset Omissions

For excess emissions that occur during Phase I, the unit has the option to offset those emissions by the following methods:

1. The unit can shift the emissions reduction requirement that the offsets represent to another affected unit, including a substitute unit under a substitution plan filed on SF# [7241].

2. The unit can offset the emissions by reducing utilization, in which case the unit must file a reduced utilization plan on SF#[7243].

(The components of and requirements for both of these plans are listed in the instructions package for the Acid Rain Program application forms, available from your EPA Regional Office or EPA Headquarters.)

3. The unit can offset emissions by deducting from the unit's Allowance Tracking System compliance subaccount for the following year the number of allowances equal to the tons of excess emissions.

4. The unit can offset emissions by installing control equipment that reduces emissions at the unit to a level that will meet the emissions limitations required under the permit, and will compensate for the additional emissions reductions required by the offset.

NOTE: If the excess emissions will be offset using only the standard offset method (i.e., deducting the entire amount of allowances equal to the tonnage of excess emissions from the unit's Allowance Tracking System Compliance subaccount for the following calendar year), mark only A 3 above.

B. You must attach the following to make the offset plan complete:

1. A schedule of compliance for reducing SO_2 emissions or obtaining additional allowances. This schedule must include the number of allowances required to be deducted from the unit's allowance tracking system account and the appropriate increments of progress for the following: reducing sulfur dioxide emissions; deducting offset allowances (include serial number of allowance) from the unit or units responsible under the plan for achieving the offsets; obtaining additional allowances; and, taking corrective action.

2. A demonstration that the reductions achieved by relying on one or more Acid Rain compliance options of 40 CFR Part 72, Subpart D is equal to the reductions required by a standard excess emissions offset plan, in accordance with paragraph §77.2(e)(5)(iii).

3. A list and description of the provisions of the current compliance plan that would be revised by the proposed offset plan. A proposed offset plan will be subject to public comment. An approved offset plan will be an administrative amendment of the permit and will not be subject to further review.

III. STANDARD PROVISIONS AND PROHIBITIONS

Part III does not require that you supply any information. Note, however, that during the offset period, the Designated Representative is prohibited from submitting an allowance transfer from the Allowance Tracking System account for the affected unit responsible for the offsets if that transfer might cause further excess emissions at the unit.

IV. CERTIFICATION

The proposed Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instruction Package for more information about the legal effect of certification.

FORMS 774 and 774A

Excess Emissions Penalty

Form 774

Excess Emissions Penalty

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 774A

Funds Transfer Deposit

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

1203790

DRAFT 774

Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Excess Emissions Penalty

Follow Instructions for Form 774.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name	C. Year

II. EXCESS EMISSIONS PENALTY CALCULATIONS

A. Total Excess Emissions:

☐ 1. This unit reported excess tons of Sulfur Dioxide totalling

☐ 2. This unit reported excess tons of Nitrogen Oxides totalling

3. Total excess tons →

B. Penalty Calculation:

1. Total excess tons *(enter A.3.)*

2. Excess emissions penalty rate (EEPAR)

3. **TOTAL PENALTY DUE** *($)* →

C. Late Payment Calculation:

1. Excess emissions penalty

2. Late payment penalty rate

3. Late payment penalty →

III. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Original Received: _____

2. Date of Initial Review: _____ By: _____

☐ Approved ☐ Disapproved

Explain: _____

_____

LOCKBOX COPY

1. Date Received at EPA Regional Office: _____ By: _____

2. Date Received at EPA Accounting Office: _____ By: _____

~~1204~~ 791

DRAFT 774A

Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Funds Transfer Deposit

Reserved for instructions

ID	TYPE
XXXXXXXX	10

AMOUNT

$

SENDER

RECEIVER TREAS NYC/ EPA

THIRD PARTY INFORMATION

FORMS #774 and 774A
EXCESS EMISSIONS PENALTY FORM

INTRODUCTION

Clean Air Act §411 and the regulations implementing that section at 40 CFR §77.4 provide that the designated representative for a unit that emits NO_x in excess of the unit's emissions limitation or emits SO_2 in excess of the allowances held for the unit shall be liable for the payment of an excess emissions penalty. The Designated Representative is responsible for calculating the penalty, and must submit the penalty without demand within sixty (60) days after the end of the calendar year in which the excess emissions occurred.

INSTRUCTIONS FOR FORM #774
EXCESS EMISSIONS PENALTY FORM

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. IDENTIFICATION

A. Enter the Acid Rain Program Identification Number and short name for the unit given in the Acid Rain permit application at Part I, Sections A and B (SF# 7231A).

B. Indicate the year for which the penalty is being submitted, i.e., the year in which the excess emissions occurred.

II. EXCESS EMISSIONS PENALTY CALCULATION

A. List the tons of excess emissions for the reporting year. This information will be in the Electronic Emissions Tracking system. For the figures entered in 1 and 2, any fraction of a ton is rounded up to equal a ton.

1. Check this box if the unit had excess SO_2 emissions and enter amount.

2. Check this box if the unit had excess NO_x emissions and enter amount.

B. Penalty Calculation

1. Enter excess tons figure from A 3.

2. Enter the Adjusted Excess Emissions Penalty Rate (AEEPR) figure. To calculate this rate, see 40 CFR Part 77, Appendix B.

3. Enter product, which is the penalty due.

C. Late Payment Penalty

If you submit this payment beyond the allowance transfer deadline that occurs after the end of the calendar year for which you are reporting excess emissions, you will be responsible for submitting an additional penalty, calculated as follows:

1. Enter Excess Emissions Penalty figure from B 3.

2. Enter the sum of one plus the interest rate raised to the nth power $[1 + (i)]^n$, where "i" is the interest rate and "n" is the number of months that have elapsed since the due date. See 40 CFR §77.4(c)(2) to calculate this factor.

3. Enter the product of C 1 multiplied by C 2, rounded to the nearest dollar.

The original of this form must be submitted to the Permitting Authority. Payments for penalties less than $25,000 should be made by cashier's or certified check payable to "Treasurer, United States of America, Acid Deposition Excess Emission Penalty." A copy of the form and these payments should be sent to the lockbox for the EPA Regional Office for the State where the affected unit is located, at the address specified in Figure 2 at Section III of the Forms Instruction Package.

Payments for penalties of $25,000 or more shall be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York, using SF#[774A].

III. CERTIFICATION

The proposed Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

INSTRUCTIONS FOR FORM #774A
FUNDS TRANSFER DEPOSIT

NOTE: the nine digit identifier under "ID", the "Type" number, and the eight digit receiver code will be preprinted by EPA on final form.

To submit penalty payments of $25,000 or greater, the designated representative must use a funds transfer deposit form. The designated representative must fill in the amount of the penalty in the appropriate space, and must indicate in the third party information space (in 200 characters or less)

- the name of the payer; and
- the purpose of the payment.

The payer must present the form to the bank and request a funds transfer. If the payer's bank is not a member of the Federal Reserve system, the information on this form must be provided by the payer's bank to its corresponding FRS member bank before the transfer can be made. The bank should transmit the funds over the Federal Reserve Communication System (FEDWIRE) to the Federal Reserve Bank in New York.

APPENDIX B TO PART 77—METHOD FOR ADJUSTING EXCESS EMISSIONS PENALTY RATE

1.0 Applicability

1.1 This Appendix establishes the method for adjusting the Acid Rain excess emissions penalty rate annually for inflation in accordance with Section 411(c) of the Act.

2.0 Principle

2.1 Each year the statutory base excess emissions penalty rate ($2000 per ton) shall be adjusted for inflation using the Consumer Price Index (CPI).

2.2 By October 15 of each year, the Administrator will publish the CPI - adjusted excess emissions penalty rate (AEEPR) for that year using the formula specified in 3.0, below.

2.3 The CPI for 1990 was 124.6.

3.0 Adjusted Excess Emissions Penalty Rate (AEEPR) Calculation.

3.1 The AEEPR can be determined using the following formula:

$$AEEPR = EEPAR \times 2000$$

3.2 The EEPAR can be determined using the following formula:

$$EEPAR = 1 + \{ [CPI(year) - CPI(1990)] \div CPI(1990) \}$$

3.3 The EEPAR is then rounded to the nearest thousandths place.

3.4 Multiply EEPAR by the $2000 statutory base penalty to derive AEEPR.

4.0 Example

4.1 Calculate the adjusted excess emissions penalty rate for excess emissions that occur in 1997, assuming that the CPI on the date of enactment was 124.6 and the CPI for 1997 is 143.5.

4.2 (a) Subtract 124.6 (CPI 1990) from 143.5 (CPI 1997).

$$143.5 - 124.6 = 18.9$$

(b) Divide this difference by 124.6 (CPI 1990)

$$18.9 \div 124.6 = 0.15168539326...$$

(c) Add one to this quotient.

$$1 + 0.1516853926... = 1.15168539326...$$

(d) Round this sum to the nearest thousandths place.

$$1.15168539326... \approx 1.152$$

(e) 1997 EEPAR = 1.152

(f) Multiply 2000 by the EEPAR.

$$AEEPR = \$2000 \times 1.152 = \$2304$$

4.3 This example is an estimate. The actual excess emissions penalty adjusted rate for 1997 is not yet known and may differ.

APPENDIX C TO PART 77—LOCK BOX ADDRESSES

[to be added]

THE WHITE HOUSE
WASHINGTON

Date: 10-29

TO: JEFF HOLMSTEAD

FROM: JAMES A. FITZHENRY
Associate Director
Office of Cabinet Affairs
Room 239, OEOB, x2800

106 OEOB

☐ Action

☐ Comment

☒ FYI

☐ Other

TALKING POINTS TO FOLLOW

Environmental Protection Agency
Public Affairs (A-107)

EPA

Environmental News

ACID RAIN

TUESDAY, OCTOBER 29, 1991

EPA ANNOUNCES PLANS TO CUT ACID RAIN EMISSIONS IN HALF

Dave Ryan (202) 260-2981

The U.S. Environmental Protection Agency today proposed innovative, market-based rules to cut annual emissions of sulfur dioxide (SO2) 10 million tons by the year 2000 -- virtually halving 1980 utility emissions of this major contributor to acid rain. The reduction will come primarily from electric utilities, which account for 70 percent of the nation's SO2 emissions. To preserve the reduction, EPA will set a permanent national cap on annual SO2 utility emissions of just under nine million tons.

"Today's proposal breaks new ground in harnessing the power of the marketplace to improve the environment," said EPA Administrator William K. Reilly. "Market incentives and tradeable allowances will be used to cut acid rain emissions. The Bush administration believes that the economic incentives in this rule have significant advantages over traditional 'command and control' regulations in bringing about the most cost-effective pollution reductions possible."

The SO2 reduction will be accomplished in two phases: Phase I begins in 1995 and affects 110 of the biggest power plants, mostly coal-burning utilities in 21 eastern and midwestern states; Phase II, which begins at the turn of the century, further reduces emissions for the 110 large plants and sets equally stringent restrictions on about 700 smaller plants.

To achieve the emission reductions, EPA is proposing a market-based "allowance" trading system. This innovative approach was the centerpiece of the clean air legislative package proposed by President Bush in 1989, and adopted as part of the Clean Air Act Amendments of 1990.

One allowance gives a utility unit the authority to emit one ton of SO2 during or after a given year. Under the proposal, EPA would allocate allowances to existing utility units based on a

formula consisting of a specified emission rate multiplied by the unit's average fuel consumption from 1985 - 1987. A fundamental requirement of the proposal is that a utility unit must hold enough allowances to cover its total annual SO2 emissions.

Allowances, once allocated, are transferrable, allowing market forces to set their price. If a facility reduces its SO2 emissions below its level of allowances -- in other words, does better than it has to under the law -- it will have left-over emission credits it can sell to another utility or can bank for future use. By allowing utilities which can achieve emission reductions at lower costs to sell excess allowances to utilities with higher control costs, total emission reductions can be achieved in the most cost-effective manner.

Today's proposal supplements rules proposed last May, under which EPA would set aside, for EPA-sponsored auctions and direct sales, up to 2.8 percent of the total allowances that would otherwise be available to existing utility sources each year. Any private citizen, broker, utility or environmental group may acquire allowances from auctions and direct sales and profit from the trading system. One important aspect of the auctions and sales is that they will provide an opportunity for new utilities to purchase allowances. New utilities are not automatically allocated allowances under the new Clean Air Act.

As a result of these proposals, allowances will be bought, sold or banked like other commodities. EPA is encouraged by the fact that a number of utilities have already begun discussions among themselves on allowance trading. The Chicago Board of Trade recently expressed its interest in developing a "futures" market in allowances.

The key to the market-based allowance system is the ability to monitor emission reductions accurately. Today's proposal requires utilities to install and operate highly accurate, continuous emission monitoring systems and report results to EPA every three months. This ensures plant compliance and instills confidence in the market-based approach by certifying the existence and quantity of the allowances being traded.

In addition, the proposed rules provide great flexibility in permit requirements, allowing each source to tailor its emission reduction strategy to suit its specific needs. For instance, to reduce SO2 emissions a plant may switch from high-sulfur coal to cleaner-burning low-sulfur coal, or shift some of its energy production capacity from dirtier units to cleaner ones.

Finally, the proposal calls for an excess emissions penalty of $2000 for every ton of SO2 emissions that exceed a plant's allowances. This penalty, which EPA estimates to be two to three times the estimated value of an allowance, will provide a strong incentive for self-enforcement.

-more-

As a result of compliance with the proposal, EPA expects utility rates after the year 2000 to rise by a national average of .5 to 1.2 percent.

EPA Assistant Administrator for Air William G. Rosenberg praised the Acid Rain Advisory Committee, an independent advisory group which includes representatives from utilities, environmental groups, public utility commissions, state air agencies, academia and the pollution control equipment industry, for playing a significant role in crafting today's proposal in a manner likely to be acceptable to a wide spectrum of interests.

"We formed the Acid Rain Advisory Committee last year to promote collaboration and consensus-building in implementing the acid rain provisions of the new Clean Air Act," Rosenberg said. "The Committee convened six public meetings attended by hundreds of participants who provided valuable advice. Their input has unquestionably helped EPA propose a more cost-effective, workable approach.

"In addition," Rosenberg continued, "The Office of the Vice President helped bring all the involved agencies of government together to close on this rule. Their efforts in ensuring we meet the statutory deadlines of the Act were essential."

Today's proposal will appear soon in the Federal Register.

For those seeking technical information only, please contact Mia Zmud, EPA/OAIAP/Acid Rain Division (ANR-445), 401 M St., S.W., Washington, D.C. 20460, or phone 202-260-2550.

R-203 # # #