BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund to customers $143 million

DOCKET NO. 060658
Submitted for filing: January 16, 2007

DIRECT TESTIMONY
OF JOHN W. DEAN
ON BEHALF OF
PROGRESS ENERGY FLORIDA

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IN RE: PETITION ON BEHALF OF CITIZENS OF THE STATE OF FLORIDA TO REQUIRE PROGRESS ENERGY FLORIDA, INC. TO REFUND CUSTOMERS $143 MILLION

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DIRECT TESTIMONY OF

JOHN W. DEAN

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John W. Dean, and my business address is P.O. Box 1935, Frederick, Maryland 21702-0935.

Q. By whom are you employed and in what capacity?

A. I am the President of JD Energy, Inc.

Q. What do you do?

A. I direct JD Energy publications on various topics, including SO_2 and NOx emission allowance price forecasting and environmental policy analysis. JD Energy publishes Emission Allowance Price Forecasts (EAPFs), which provide monthly, quarterly, and annual price information and projections for both SO_2 and NOx allowances. I also participated in the publication of several Background Papers on topics such as the relationship between emission allowance and coal prices, as well on SO_2 equipment cost assumptions.

Q. What is the purpose of your testimony?

A. I will address the testimony of OPC's expert, Robert Sansom, regarding the sulfur dioxide ("SO_2") allowance savings realized by switching to a 50/50 blend of Powder River Basin ("PRB") coal with bituminous coal. Because PRB coal has less sulfur than bituminous coal, burning PRB coal can reduce the emissions of SO_2, which may reduce the number of allowance credits needed for each unit. My testimony analyzes whether, if Mr. Sansom's allegations as to what PEF should have been burning at Crystal River Units 4 and 5 ("CR4" and "CR5") are correct, Mr. Sansom has appropriately calculated the alleged SO_2 damages. My testimony will explain how Mr. Sansom, by relying on a generic and dated model, has over-estimated the SO_2 savings that burning a PRB coal blend would generate. In addition, because Mr. Sansom has not properly accounted for contract issues during 2000 and 2001 and for transportation issues during 2005, both of which would reduce the amount of PRB coal PEF could have received to burn at CR4 and CR5, my testimony will also provide the correct amount of SO_2 allowance savings that could have potentially been realized for the years 2000, 2001, and 2005.

Q. Please describe your education background and professional experience.

A. I received a Bachelors of Science degree from Georgetown University in Economics and Government in 1969. In 1975, I received a Masters degree in International Economic Relations from the University of Maryland. I have been the President of JD Energy, Inc. from December 1987 to the present. From 1982-1986, I served as Director of Coal Service, Data Resources, Inc., where I conducted major studies on various topics related to electric utilities, including the financial and energy impacts of the passage of the acid rain legislation. I also worked in various positions from 1977-1981 at the U.S. Department of Energy (DOE), including Deputy Director (Supervisory Industrial Economist) of the Division of Coal and Alternate Fuel Regulation. While at the DOE, I supervised preparation of fuel, financial, engineering, and environmental analyses used to assess coal use in utility and industrial sectors. From 1974-1977, I was the Director (Economist) of the Industrial Division in the Office of Coal Utilization at the U.S. Federal Energy Administration (FEA). In that position I supervised a staff of sixteen people in the preparation of site-specific fuel, engineering, and environmental analyses to determine the financial and economic feasibility of coal conversion.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring the following exhibits, which were created by me or under my direction.

- Exhibit No. __ (JWD-1), which is a composite exhibit of two graphs depicting the prices for SO_2 allowances for the years 1993-2005;
- Exhibit No. __ (JWD-2), which is Mr. Sansom's response to Interrogatory Number 18, showing the steps of his SO_2 damages calculations;
- Exhibit No. __ (JWD-3), which is a composite exhibit of excerpts from the voluminous Chapter of the AP-42 Manual upon which Mr. Sansom relies (the entire Chapter can be reviewed at www.epa.gov);
- Exhibit No. __ (JWD-4), which is a chart showing the corrected mathematical calculations of Mr. Sansom's SO_2 allowance damages;

- Exhibit No. __ (JWD-5), which is a composite exhibit of portions of the voluminous background document to the AP-42 Manual (the entire background document can reviewed at www.epa.gov);
- Exhibit No. __ (JWD-6), which is the Introduction to the AP-42, Volume I, Fifth Edition;
- Exhibit No. __ (JWD-7), which is a composite exhibit of portions of the voluminous related Emission Inventory Improvement Program ("EEIP") document to the AP-42 Manual (the entire EEIP document can be reviewed at www.epa.gov);
- Exhibit No. __ (JWD-8), which is a chart showing the calculation of SO_2 allowance damages without the ash savings;
- Exhibit No. __ (JWD-9), which is a chart showing the calculation of SO_2 allowance damages with the adjusted PRB tonnage amounts for 2000, 2001, and 2005;
- Exhibit No. __ (JWD-10), which is a chart showing the calculation of SO_2 allowance damages taking into account all adjustments.

All of these exhibits are true and correct.

Q. Please summarize your testimony.

A. PRB coal emits less SO_2 when burned, as compared to bituminous coal, which would reduce the number of SO_2 allowances that a company would need to use or purchase. The SO_2 allowance price market is characterized by its volatility. While prudent utilities consider the price of SO_2 allowances when making fuel decisions, no utility would or should rely solely on price forecasts of SO_2 allowances to make major decisions.

Mr. Sansom, in calculating the alleged number of SO_2 allowances that the Company could have saved by switching to a 50/50 blend, relies on the AP-42 Manual to determine the additional SO_2 that will be retained in the ash when burning PRB coal. The AP-42 Manual, however, is too generic and unreliable to be used as a basis for calculating the amount of damages relating to a specific boiler or set of boilers. Therefore Mr. Sansom has over-estimated the alleged number of SO_2 allowances by using an unreliable source.

In addition, as testified to by Jamie Heller, Mr. Sansom does not calculate the correct amount of PRB coal that PEF could have burned at CR4 and CR5 during the years 2000, 2001, and 2005. For 2000 and 2001, due to contractual obligations for bituminous coal, PEF could not have purchased as much PRB coal. Mr. Sansom also does not correctly account for the transportation problems with the PRB coal in 2005 and therefore the amount of PRB coal that PEF could have bought that year should be reduced. The reduced PRB for these three years results in a reduction in the alleged SO_2 allowances that would have been saved.

Taking these factors into account results in a reduction of Mr. Sansom's calculated alleged SO_2 damages from $17,928,717 to $15,015,204.

II. GENERAL OVERVIEW OF SO_2 MARKET

Q. Please explain the development of the SO_2 market.

A. In 1990, amendments to the Clean Air Act ("CAA"), which included the Acid Rain Legislation or Title IV, were passed by Congress. This comprehensive legislation provided for national regulation of SO_2 emissions from existing sources of SO_2, including existing coal-fired power plants, in an attempt to reduce SO_2 emissions. The CAA amendments introduced SO_2 reductions in two phases. Phase I was introduced in 1995, and it applied SO_2 limits to the 103 highest SO_2-emitting power plants in the country. Phase II did not begin until 2000, when virtually all units with a capacity of more than 25 MW of power were required to comply with Title IV.

A major result of the CAA amendments was the creation of a cap and trade system for SO_2 emission allowance credits. Trading under the Title IV amendments began in about 1993, just before Phase I was implemented. Pursuant to the CAA amendments, each year the Environmental Protection Agency ("EPA") allocates a certain number of SO_2 allowances for each electric power plant covered by the legislation. This number is determined based upon the plant's historical use of the unit. One allowance permits the holder of that allowance to emit one ton of SO_2. The allowances can be used, traded, or they can be banked, meaning that an allowance purchased in a particular year does not necessarily have to be used in that year but can be used in a subsequent year. To comply with the CAA amendments, the plant must provide the EPA with an adequate number of allowances to account for the number of tons of SO_2 it has emitted that particular year.

So each plant has two choices. It can take measures to reduce its SO_2 emission by, for example, installing a scrubber, which keeps almost all of the SO_2 from being emitted into the air, or by burning lower-sulfur coal. The plant could then take the SO_2 credits allocated to it by the EPA and sell them to other power plants. In the alternative, the plant could choose to not reduce its SO_2 emissions and rather purchase additional SO_2 allowances from those plants that have taken other measures to reduce SO_2 emissions. This creates a market for SO_2 allowances. Anyone, including brokers and individuals, can buy and sell SO_2 allowances. So the market is not limited just to power plant owners and operators.

Q. **How are prices for SO_2 allowances determined?**

A. When the market first came about, the process for determining market prices was more difficult than it is now. At first, the market was not as transparent because of limited information provided by a few brokers and the only real tracking system for allowances was maintained by the EPA. This system, known as the Allowance Tracking System, only required companies to report allowances when they were transferred. There was, and still is, no requirement to report the sale or purchase of allowances. Today, though, there is more market transparency because: 1) a wider spectrum of organizations, which include brokers and press reports, now publish a greater array of information on trading; and 2) a higher volume of trades are occurring on a consistent basis. Market prices are determined by tracking the various reports of the number of allowances traded and the prices. Market forecasting also includes an analysis of future events, like government actions, to determine how the market is likely to change.

Q. **Is the SO_2 market similar to the stock market?**

A. In some ways, it is like a stock market. Allowances are traded much like stocks, and the SO_2 allowance market, like the stock market, is volatile and responds to very short-term events. However, the SO_2 allowance market is even more unpredictable in its price fluctuations than the stock market. This is due in large part to the fact that the SO_2 allowance market is still a very thinly-traded market. One or two players can make trades on the SO_2 market and have a dramatic impact on the prices. It is impossible to predict when such individual trades will occur.

Q. **Can you provide any other examples to show how the SO_2 market is volatile?**

A. Yes, as another example, in 1999, the EPA issued a series of notices of violation to a large number of power companies for alleged violations of New Source Review. New Source Review is a CAA requirement that ensures that air quality is not significantly degraded from the addition of new and modified factories, industrial boilers and power plants. The violations were issued because power plants had allegedly made certain significant modifications to the plants without first obtaining a permit. Once the EPA issued these notices, the market value of allowances crashed, from approximately $200/ton down to $130/ton. The price decreased rapidly, because many companies were afraid that the EPA's crack-down on violations of New Source Review would force plants to install scrubbers, thereby eliminating the need to purchase allowances. I am not aware of any market forecasting companies that predicted this sharp dip in allowance prices preceding the news that the notices of violation would be issued.

The volatility of the SO_2 allowance market can be seen in Exhibit No. __ (JWD-1). Page 1 of this exhibit reflects a graph depicting the prices for SO_2 allowances for the years 1993-2005. This graph depicts the large, and unexpected, price jump in SO_2 prices that occurred in 2005, when prices on some days were more than $1600/ton. Even though the line on the price of SO_2 allowances up until 2004 appears relatively flat, the price for these years does fluctuate $100-$200/ton. To more accurately reflect the volatility of the SO_2 allowance prices during these years, I have included, on page 2 of Exhibit No. __ (JWD-1), a second graph that charts prices from 1993-2003. This second graph shows that SO_2 allowance prices have always fluctuated.

Q. **How have other owners of SO_2 sources reacted to this volatile market?**

A. Most owners of SO_2 sources generally consider it much too risky to make major decisions based solely on the price of SO_2 allowances in the market. In fact, my company, JD Energy, regularly does forecasts of SO_2 allowance prices, and the process is extremely difficult. The price is impacted by regulatory and political factors at the local, state, regional, as well as the federal levels, that are hard to predict. Given the unpredictability, it is unwise for a utility to make decisions on coal procurement based solely on the expected prices of SO_2 allowances. While SO_2 allowance prices should certainly be a factor in the decision, the utility must take into consideration the market's volatility and risk.

III. EMISSION DIFFERENCES BETWEEN SUB-BITUMINOUS AND BITUMINOUS COALS

Q. **Please explain the differences between PRB (sub-bituminous) coal, and bituminous coal, in terms of SO_2 emissions.**

A. PRB, a sub-bituminous coal, generally contains a lower sulfur content than bituminous coal. On average, PRB coal, with a heating value of approximately 8800 Btu/lb., generally contains about 0.6 pounds of SO_2 per million Btu (MMBtu). Comparatively, bituminous coal contains anywhere from about 0.8 to 6.0 pounds per

MMBtu. The Central Appalachian coal in question with regards to CR Units 4 and CR5 contains about 1.0 to 1.2 pounds per MMBtu. When coal is burned in a plant, a certain amount of SO_2 is released through the stack into the air. One would expect that PRB coal would emit less SO_2 than bituminous coal, given its lower sulfur content. In addition, due to the ash and alkaline characteristics of sub-bituminous coal, burning a sub-bituminous coal will probably result in more SO_2 being captured in the coal ash than would be captured in bituminous coal ash. In other words, even less SO_2 is emitted into the air when burning sub-bituminous coal. I will refer to this as increased SO_2 ash savings.

Q. How can the reduction in SO_2 emissions that is realized when burning sub-bituminous coal be quantified?

A. The best way to calculate the difference in SO_2 emissions between burning sub-bituminous versus bituminous coal is to actually evaluate the stack emissions emitted from the actual boiler for which the reduction is to be calculated. Where an actual burn is not feasible, the calculation is relatively straightforward based on the coal's heating value and sulfur content. First the difference in average SO_2 emissions, expressed in pounds per MMBtu, of the two types of coal is calculated. This reduced value is then multiplied by the total MMBtu of coal that would be displaced by the lower SO_2-emitting coal on an annual basis at the unit. The result is the amount of reduction in SO_2 emissions for burning the sub-bituminous coal.

Q. How do you account for the increased SO_2 ash savings that are realized when burning sub-bituminous coal?

A. It is rather difficult to calculate, with any sort of precision, the increased amount of SO_2 ash savings. The amount of SO_2 ash savings realized when burning sub-bituminous coal is boiler-specific. It is difficult to use averages of other units and boilers to approximate the additional SO_2 ash savings. Short of actually measuring the decreased SO_2 emitted when actually burning sub-bituminous coal in a particular unit, there is no scientifically reasonable method to calculate the amount of SO_2 ash savings.

IV. CALCULATION OF DAMAGES

Q. Have you reviewed Mr. Sansom's calculation of the damages regarding the SO_2 allowances?

A. Yes, I have reviewed his calculations and his workpapers provided to explain his calculations.

Q. Can you explain how Mr. Sansom has calculated the damages?

A. Yes. To better explain, I have attached, as Exhibit No. __ (JWD-2), Mr. Sansom's response to Interrogatory Number 18, in which Mr. Sansom provides a chart to show the steps of his SO_2 damages calculations. First, in column 1, he provides his calculation of the average SO_2 content of coal deliveries to CR4 and CR5 according to FERC 423 data. Column 2 reflects his estimation of the SO_2 emission rate of PRB coal multiplied by 0.9. The 0.9 apparently reflects his assumption that sub-bituminous coal will result in 10% additional SO_2 ash savings, as compared to bituminous coal. By subtracting column 2 from column 1, Mr. Sansom, in column 3, provides his estimate of the savings in SO_2 emission that will result from burning sub-bituminous coal. Next, in column 4, Mr. Sansom provides, in MMBtu, the total amount of coal shipped to CR4 and CR5 multiplied by 0.4, representing the 40% of the shipments, in Btu's, that would be PRB coal in a 50/50 PRB/bituminous tonnage mix. By multiplying column 4 and column 3, and converting to tons, Mr. Sansom determines the excess tons of SO_2, which is also the number of allowances that would have allegedly been saved by PEF. Finally, he multiplies the number of allowances (in column 5) by the average market price of the allowances (column 6), to determine the yearly damages (column 7).

Q. What method has Mr. Sansom used to support his assumption that burning PRB coal will result in a 10% SO_2 ash savings?

A. According to OPC's response to Interrogatory Number 18, Mr. Sansom uses the EPA's AP-42 manual to determine the decreased emitted sulfur when burning PRB coal as compared to burning bituminous coal. Relevant excerpts from the Chapter of the AP-42 Manual upon which Mr. Sansom relies are found in Exhibit No. __ (JWD-3). Specifically, I assume Mr. Sansom is using the generic comment provided in footnote b to Table 1-1.3 of the AP-42 Manual (page 14 of Exhibit No. __ (JWD-3)), which states that 95% of bituminous coal is emitted as SO_2, compared to sub-bituminous coal, which retains about 10% more SO_2 in the ash.

Q. What is the AP-42 Manual?

A. The AP-42 Manual is published by the EPA and attempts to estimate the emissions factors for various pollutants, including those from burning different types of coal. An emission factor is a representative value that attempts to relate the quantity of a pollutant released into the atmosphere with an activity associated with the release of that pollutant. In other words, it is a way to estimate the amount of pollutant that will be emitted into the air while doing a certain activity. The AP-42 Manual includes emission factors for burning bituminous coal and burning sub-bituminous coal.

Q. Assuming that Mr. Sansom has properly relied upon the AP-42 Manual, has Mr. Sansom applied the AP-42 Manual methodology correctly?

A. No, Mr. Sansom makes several mathematical errors. First, he uses an incorrect percentage by relying on the general percentage difference of 10%, which is inferred from footnote b of Table 1-1.3 of the AP-42 Manual. By performing simple calculations using the data actually contained within the table itself, the actual difference in percentages of SO_2 remaining in the ash is 7.5%, not 10%. In other words, pursuant to the calculations contained in the AP-42 Manual, while a bituminous coal retains 5% of SO_2 in the ash, sub-bituminous coal retains 12.5% of the SO_2 in the ash. Mr. Sansom, by using the approximations contained in the footnote to the table, has overestimated the amount of SO_2 ash savings.

In addition, when Mr. Sansom calculates the difference between these two ash percentages, he makes a fundamental mathematical error. Rather than calculating 5% of the bituminous coal, then calculating the 15% of the ash for the portion that would be sub-bituminous coal, and then subtracting those two numbers, Mr. Sansom apparently simply subtracts the two percentages to get 10% in additional sulfur remaining in the ash. To be mathematically accurate, however, the percentages must first be applied and then the difference calculated.

Q. Have you calculated the differences the correct way?

A. Yes, I have prepared an exhibit that reflects both the correct 7.5% SO_2 ash savings figure, as well as the correct application of the percentages (i.e. first multiplying the percentages and then subtracting the two figures). In preparing these calculations, I also realized that, for the year 2002 data, Mr. Sansom made another error that reduced the number of allowances needed in that year. To be accurate, I calculated these numbers the correct way, even though that results in a higher amount of SO_2 damages for 2002. The results of these new calculations, along with the new number of allowances saved, are reflected in the attached Exhibit No. __ (JWD-4) to my testimony. To summarize the calculations, just by correcting Mr. Sansom's mathematical errors in applying the AP-42 Manual, the alleged SO_2 damages over the 2000-2005 period decrease from $17,928,717 to $16,791,995.

Q. You have commented on Mr. Sansom's application of the AP-42 Manual. Do you have any issues with Mr. Sansom relying on the AP-42 Manual at all?

A. Yes, I have several issues with Mr. Sansom using the AP-42 Manual to justify the calculation of damages. First, the manual is only a generic description of the differences between bituminous and sub-bituminous coals regarding several different emissions, including SO_2. The background document explaining the procedures for developing the AP-42 Model indicates that the emission factors generally represent a population average of facilities in the source category. The relevant portions of this background document are attached as Exhibit No. __ (JWD-5) to my testimony. In other words, the emission factors appear to be an average of a limited sampling of coal-burning facilities. The problem with reliance on an average of other facilities is that, as explained above, the ash content that results from burning various coal types can vary greatly among plants. The SO_2 ash savings determination is a boiler-specific calculation, and it cannot be readily ascertained from an average of data from other units. Further, the Introduction to the AP-42 itself recognizes that whenever the emission factors are used "one should be aware of their limitations in accurately representing a particular facility." See page 3 of Exhibit No. __ (JWD-6). And the disclaimer section of a related Emission Inventory Improvement Program ("EEIP") document indicates that "the choice of methods to be used to estimate emissions depends on how the estimates will be used and the degree of accuracy required. Methods using site-specific data are preferred over other methods." See attached Exhibit No. __ (JWD-7).

Q. What other problems exist with Mr. Sansom's reliance on the AP-42 Manual?

A. Emissions factors are only as valid as the underlying data from which they were derived. The chapter regarding differences in emissions between bituminous and sub-bituminous coals relies on test burns conducted at a very limited number of plants. The mean average from these test burns were used to calculate the emission factors. Such a small sample size does not result in meaningful data that can be used to accurately predict how the coals will react in a particular unit. Another problem with the sample size is that there is a wide variation in the results of each of those samples. Statistically speaking, if the samples that are tested result in a wide variation of output, they will result in a high standard deviation. This means that the data are far from the mean average, and thus the mean average is not a good representation of the data sources.

For example, according to the 1993 Background Document regarding the chapter on bituminous and sub-bituminous coal, the original emission factor for bituminous coal used in a PC-fired boiler, under the 1988 version of the AP-42, was 39S (with "S" being the percent of sulfur in the coal). The 1993 revision to this chapter of the AP-42 included data from two additional PC-fired units, which were tested to measure the emissions when burning bituminous coal. One of the units resulted in a factor of 37.43, which was the average of seven different runs completed at the unit. The other unit resulted in a factor of 38.78, which was the average of three runs at the unit.

It is important to note as well that this second unit was apparently burning sub-bituminous coal, because the coal had a stated heating value of 8,104 Btu and a 0.44 percent sulfur content. But the data from this unit was used to calculate the emission factor for bituminous coal. In any event, the average of these two units gives a factor of 38.1.

The authors of the AP-42 then apparently reviewed the prior 1988 data, which had set the emission factor at 39S, and revised the emission factor to 38S, based on the results of the two additional units. The relevant portions of this document can be found at pages 9 through 16 of the attached Exhibit No. __ (JWD-5). It is unclear whether the data from the two additional units was averaged with the data used in 1988, or whether the data from the additional units simply replaced the former data. What is clear from this data, however, is that the sample size is too limited and the resulting data is too variable to produce anything more than an approximation of emission rates.

What's more, the data from which these emission factors is rather dated. The last time additional data was added to the calculations for the SO_2 emission factor of bituminous coal was 1993, when the above-described data was included in the calculation. New data from units burning sub-bituminous coal was not provided in the 1993 update, so the last time the sub-bituminous coal emission factor was updated was in 1988. Coal quality has changed significantly since that time period, particularly for sub-bituminous coal. Even Mr. Sansom, in his testimony at page 13, recognizes that a different type of PRB coal was being mined starting in the late 1980s. This difference is another significant flaw in the underlying data. Coal quality differences could potentially result in varying reactions when burned in units.

Q. Are there any other reasons reliance on the AP-42 Manual to calculate SO2 ash savings is unreliable?

A. Yes, there are also issues with the accuracy of the data used in the 1988 version of the AP-42 Manual. The 1993 Background Document explains that certain "spot checking" of the prior data was conducted. In this spot check, one of the test reports checked had a "discrepancy" in the fuel analysis procedures. This test report, done at the "ALMA" site, produced data for both bituminous and sub-bituminous coal. Correcting the data for the bituminous coal data resulted in a change from 33S to 33.7S. But the author of the document concluded that this change was not significant enough to change the emission factor background data or change the emission factor itself. Likewise, with the sub-bituminous coal data, the author concluded that "making these corrections did not effectively change the site data point." See page 9 of Exhibit No. __ (JWD-5). These errors were found in a random spot check of only some of the data sources upon which the 1988 emission factors were calculated. Such errors call into question the accuracy of the data itself, as well as the methodology used to gather and analyze the data.

Q. If you were to calculate the SO_2 savings from burning sub-bituminous coal, would you rely on the AP-42 Manual to estimate the additional SO_2 retained in the ash?

A. No. As explained above, the AP-42 Manual is too generic and unreliable to be used as a basis for calculating the amount of damages relating to a specific boiler or set of boilers. In fact, when I advise clients as to whether to make a fuel switch, I do not include a calculation of the SO_2 savings kept in the ash. The actual amount of savings that will be experienced in each client's individual boiler can vary too much, and it would be speculative to artificially assign a percentage savings to the calculation. Mr. Sansom is attempting to use a document that is meant to be an approximation of what might occur when burning these coals in a very precise way. His reliance on this general information to support a calculation of damages is misplaced and inappropriate.

Q. Please explain how the emission factors in the AP-42 Manual are rated.

A. Each emission factor is assigned a letter ranking to judge the quality of the underlying data and how well the factor represents the emission source. An "A" rating is the best, while an "E" rating is the worst. An "A" rating indicates that the underlying data was taken from many randomly chosen sources in the industry population.

Q. What rating have the emission factors provide in Table 1-1.3 been assigned and does this rating affect your opinion as to their validity?

A. The emission factors in Table 1-1.3, upon which Mr. Sansom relies in his SO_2 ash savings calculation, do appear to have an "A" rating. This, however, does not change my opinion as to the validity of reliance on the emission factors to calculate SO_2 ash savings. As I explained above, the ash characteristics of burning various coals can vary greatly among individual boilers. While the impact of the lower sulfur content of each coal can be readily calculated, the SO_2 ash savings is too boiler-specific to be estimated, even using data from a number of other units. Furthermore, the emission factor was assigned its "A" rating at the time the emission factor was calculated. So the emission factor rating for bituminous coal was assigned in 1993, and the emission factor rating for sub-bituminous coal was assigned in 1988. Again, information this dated cannot be relied upon today for purposes of assessing damages. Indeed, the fact that so many years have passed, and much of the original background test data is no longer available, calls into question the accuracy of the emission factor rating.

Q. Are you disputing that burning sub-bituminous coal will result in more SO_2 being retained in the ash than with burning bituminous coal?

A. No, I acknowledge that an additional amount of SO_2 will likely be retained in the ash with sub-bituminous coal, as compared to bituminous coal. I cannot, however, within a reasonable degree of certainty, calculate what that percentage will be in a particular unit. In this case, Mr. Sansom is using the AP-42 Manual to prove that burning sub-bituminous coal at CR4 and CR5 will result in a specific percentage of SO_2 ash savings. Certainly, if sub-bituminous coal was burned at CR4 and CR5, I would expect there to be some unspecified higher SO_2 ash savings than with burning bituminous coal. But because the amount of that ash savings is subject to variation based on the nuances of the CR4 and CR5 units, it is inappropriate for Mr. Sansom to tack on additional SO_2 damages based on the average data from other units. Mr. Sansom's attempt to value the SO_2 ash savings is speculative. I would characterize his calculation as "back of the envelope" and not reliable enough to support damages to a reasonable degree of certainty.

Q. Have you calculated the amount of damages, without the speculative SO_2 ash savings calculations?

A. Yes, I have re-calculated the amount of damages by eliminating the additional SO_2 ash savings. The results of my calculations are reflected in the attached Exhibit No. __ (JWD-8) to my testimony. In this chart, I did not multiply the SO_2 content of the bituminous (column 1) or sub-bituminous (column 2) coals by any ash-related reduction formula. Rather, I subtracted the two SO_2 levels directly. The remaining calculations were performed the same way as the other tables. By calculating the damages without the speculative SO_2 ash savings, the amount of SO_2 damages are reduced from Mr. Sansom's original \$17,928,717 to \$15,989,653.

IV. MISCELLANEOUS ISSUES AND FURTHER ADJUSTMENTS

Q. Do you have any other adjustments to make to Mr. Sansom's alleged SO_2 damages?

A. Yes, based on the calculations done by Jamie Heller for various other issues which affect the amount of PRB coal that PEF could have burned at CR4 and CR5, I have made some other adjustments to the alleged SO_2 damages.

Q. Can you please explain these adjustments?

A. Yes, for the years 2000 and 2001, Mr. Heller has adjusted the amounts of PRB coal based on existing long-term contracts under which PEF was obligated to purchase a particular tonnage of bituminous coal for delivery by barge. These contract obligations displaced part of the PRB coal that Mr. Sansom alleges should have been burned at CR4 and CR5. Mr. Heller, taking these contract constraints into account, calculates that the PRB coal, as a percentage of Btu's, would have been 33.1% for 2000 and 34% for 2001.

Q. Does Mr. Heller make any other adjustments to the amount of PRB coal?

A. Yes. On page 53 of Mr. Sansom's testimony, Mr. Sansom acknowledges that transportation issues during 2005 decreased the amount of PRB tons that plants were able to receive. As a result, the plants were forced to replace the PRB coal with coal from other sources. Accordingly, Mr. Sansom makes a 7.5% downward adjustment to the number of PRB tons PEF should have burned at CR4 and CR5.

Mr. Heller, in his testimony, points out that, while Mr. Sansom claims to have made this 7.5% adjustment for 2005, Mr. Sansom in fact does not include this reduction in his damages calculations. Accordingly, Mr. Heller has calculated that the amount of PRB coal, as a percentage of Btu's of the total coal shipped to CR4 and CR5, would be reduced from 40% to 37% for 2005.

Q. **How, if at all, do the additional adjustments for 2000, 2001, and 2005, supported by Mr. Heller's testimony, affect the SO_2 damages calculations?**

A. If the actual PRB coal deliveries for the years 2000, 2001, and 2005 were less than Mr. Sansom assumed in that year, then PEF would have been burning more bituminous coal in its blend at CR4 and CR5. This necessarily would increase the amount of SO_2 emissions from CR4 and CR5, which decreases the level of allowance "savings" claimed by Mr. Sansom for each of those years.

Q. **Have you calculated the amount of damages based on Mr. Heller's revised PRB amounts for 2000, 2001, and 2005?**

A. Yes, I have adjusted the amounts of PRB coal for each of these years based on Mr. Heller's analysis. These calculations are reflected in the attached Exhibit No. __ (JWD-9) to my testimony. By adjusting the number of PRB tons for 2000, 20001, and 2005, and taking into account Mr. Sansom's mathematical errors, the amount of alleged SO_2 damages are reduced from Mr. Sansom's original $17,928,717 to $15,771,411.

Q. **So taking the mathematical errors, the removal of the ash savings, and the adjusted 2000, 2001, and 2005 supply numbers, into account, what is the final, reduced amount of alleged SO_2 damages?**

A. Factoring in all these issues, as explained in detail above, the final amount of alleged SO_2 damages are reduced from Mr. Sansom's original amount of $17,928,717 to

$15,015,204, as reflected in my attached Exhibit No. __ (JWD-10). This represents a total reduction of $2,913,513 in alleged SO_2 damages.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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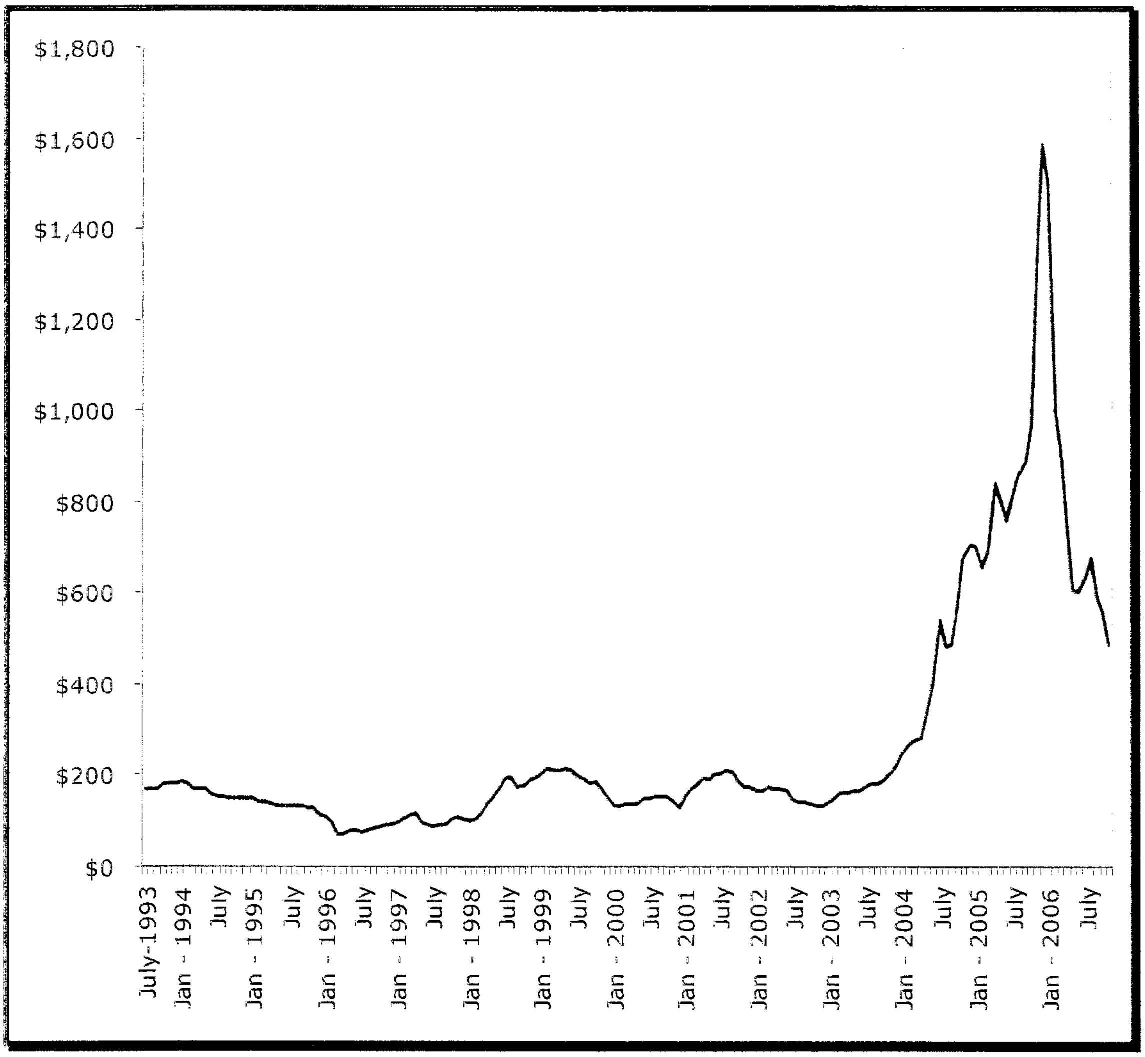
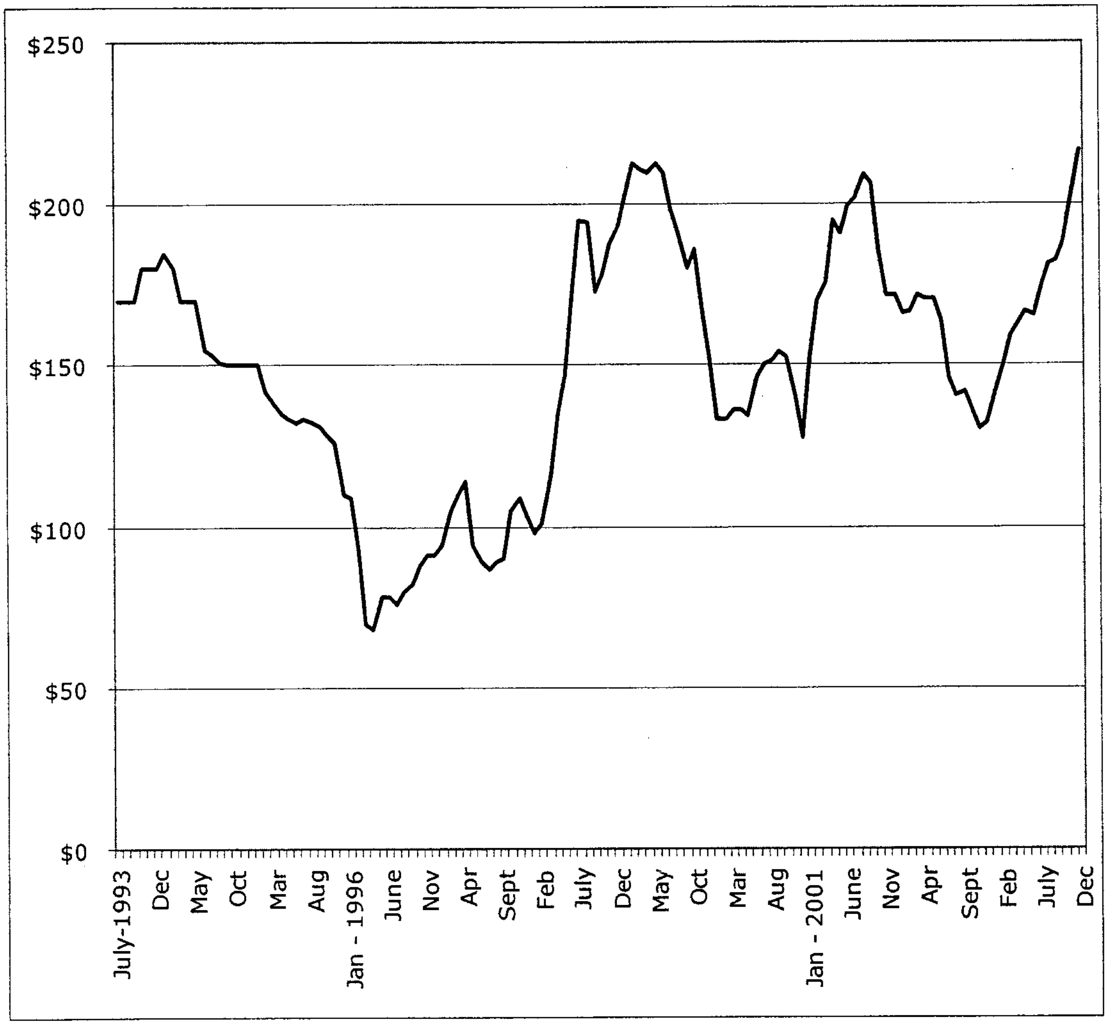
Progress Energy Florida
Exhibit No. ____ (JWD-1)
Page 1 of 2

SO2 ALLOWANCE PRICES, JULY 1993 - NOVEMBER 2006



DOCKET 060658
Progress Energy Florida
Exhibit No. ____ (JWD-1)
Page 2 of 2

SO2 ALLOWANCE PRICES, JULY 1993 - DECEMBER 2003



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Progress Energy Florida
Exhibit No. _____ (JWD-2)
Page 1 of 5

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund customers $143 million	DOCKET NO. 060658-EI

CITIZENS' ANSWERS TO PROGRESS ENERGY FLORIDA'S FIRST SET OF INTERROGATORIES TO OFFICE OF PUBLIC COUNSEL (NOS. 1-25)

1. Please refer to Mr. Sansom's testimony at page 14, lines 5-6, and Exhibit RS-7 and identify the specific document(s) used to develop Exhibit RS-7 and the price listed on page 14 at line 6.

ANSWER: The illustrative $5.00/ton used on p. 14 was intended to be and was comfortably above the then prevailing price for PRB coal, FOB mine, as reported in *Coal Daily*. See documents provided in response to interrogatory number 1, consisting of PRB mine prices, FOB mine, for various dates, as published in *Coal Daily*. See also documents incorporated by reference in RS-6.

18. Please refer to Exhibit RS-26 of Mr. Sansom's testimony and identify:

(a) each step of the calculation of the "Excess SO2 Allowance Cost" for each year from 2000 through and including 2005 for the "Excess SO2 Allowance Cost $" column in Exhibit RS-26;

Year	(1) # SO2 per MMBtu Bitum.	(2) # SO2 per MMBtu PRB x 0.9	(3) Δ SO2 per MMBtu	(4) MMBtu x 1,000	(5) Excess SO2 Tons	(6) SO2 Allowance Price $/Ton	(7) Excess SO2 Cost ($)
2000	1.12	0.54	0.58	36,317	10,619	141	1,497,278
2001	1.11	0.54	0.57	35,796	10,202	186	1,897,541
2002	1.12	0.54	0.58	37,753	9,277	152	1,410,049
2003	1.03	0.54	0.49	32,781	8,031	176	1,413,510
2004	1.04	0.54	0.50	37,980	9,495	442	4,196,799
2005	1.02	0.54	0.48	34,347	8,293	906	7,513,540

1. SO2 content of CR 4/5 deliveries to IMT from FERC 423 (see response to IR 5).
2. SO2/MMBtu of PRB coal to TECO ECT from 2000-2002 and 0.6# SO2/MMBtu thereafter times 90% to reflect higher percent removal in ash of SO2 in PRB coal (12.5%) vs. bituminous coal (2.5%). Using U.S. EPA AP-42, a 1.2# SO2 bituminous coal would emit 0.95 times 1.2 lbs. SO2/MMBtu or 1.14 lbs. SO2/ MMBtu and a 6.0 lbs. SO2/MMBtu subbituminous coal would emit 0.6 lbs. SO2/MMBtu times 0.85 or 0.51 lbs. SO2/MMBtu for a difference of 0.63 lbs. SO2/MMBtu.
3. Column (1) minus Column (2).
4. Total MMBtu shipped by rail to CR 4/5 and by water to IMT times 0.4 to reflect 50/50 blend on a tonnage basis.
5. Higher SO2 emissions without PRB: Column (3) times Column (4).
6. Cantor Fitzgerald Monthly Price Index at emissions trading.com.
7. Column (5) times Column (6).

(b) all assumptions made in the calculations for the "Excess SO2 Allowance Cost" identified in response to interrogatory number 18(a);

ANSWER: See IR 18(a) above.

(c) the sulfur content of the CAPP coal(s) used and the sulfur content of the PRB coal(s) used in the calculations of the "Excess SO2 Allowance Cost" and the source document(s) for the types of coals used in these calculations;

ANSWER: See IR 18(a) above.

(d) the "market value" numbers for the SO2 allowance used by Mr. Sansom in the calculation of the "Excess SO2 Allowance Cost" in Exhibit RS-26; and;

ANSWER: See IR 18(a) above.

(e) the source document(s) used for the calculations, assumptions, sulfur content, and market value of the SO2 allowances used in the calculations of the "Excess SO2 Allowance Cost" in Exhibit RS-26 and referred to in response to interrogatory number 18 (a) through 18 (d).

ANSWER: See IR 18(a) above.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Office of Public Counsel's Answers to Progress Energy Florida's First Set of Interrogatories has been furnished by electronic mail and U.S. Mail on this 20th day of November, 2006, to the following:

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1.1 Bituminous And Subbituminous Coal Combustion

1.1.1 General

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen, although no single parameter defines a rank. Typically, coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases.

Bituminous coals are by far the largest group and are characterized as having lower fixed carbon and higher volatile matter than anthracite. The key distinguishing characteristics of bituminous coal are its relative volatile matter and sulfur content as well as its slagging and agglomerating characteristics. Subbituminous coals have higher moisture and volatile matter and lower sulfur content than bituminous coals and may be used as an alternative fuel in some boilers originally designed to burn bituminous coals.[1] Generally, bituminous coals have heating values of 10,500 to 14,000 British thermal units per pound (Btu/lb) on a wet, mineral-matter-free basis.[2] As mined, the heating values of typical U.S. bituminous coals range from 10,720 to 14,730 Btu/lb.[3] The heating values of subbituminous coals range from 8,300 to 11,500 Btu/lb on a wet, mineral-matter-free basis[2], and from 9,420 to 10,130 Btu/lb on an as-mined basis.[3] Formulae and tables for classifying coals are given in Reference 2.

1.1.2 Firing Practices[4]

Coal-fired boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and the firing configuration (suspension, stoker, or fluidized bed). The most common heat transfer method for coal-fired boilers is the watertube method in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes.

Coal-fired watertube boilers include pulverized coal, cyclone, stoker, fluidized bed, and handfed units. In stoker-fired systems and most handfed units, the fuel is primarily burned on the bottom of the furnace or on a grate. In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. In pulverized coal-fired (PC-fired) boilers, the fuel is pulverized to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200-mesh sieve) and pneumatically injected through the burners into the furnace. Combustion in PC-fired units takes place almost entirely while the coal is suspended in the furnace volume. PC-fired boilers are classified as either dry bottom or wet bottom (also referred to as slag tap furnaces), depending on whether the ash is removed in a solid or molten state. In dry bottom furnaces, coals with high fusion temperatures are burned, resulting in dry ash. In wet bottom furnaces, coals with low fusion temperatures are used, resulting in molten ash or slag.

Depending upon the type and location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into two different firing types, including wall, and tangential. Wall-fired boilers can be either single wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed wall-fired, with burners mounted on two opposing walls. Tangential (or corner-fired) boilers have burners mounted in the corners of the furnace. The fuel and air are injected tangent to an imaginary circle in the plane of the boilers. Cyclone furnaces are often categorized as PC-fired systems even though the coal is crushed to a maximum size of about 4-mesh. The coal is fed tangentially, with primary air, into a horizonal cylindrical furnace. Smaller coal particles are burned in suspension while larger particles adhere to the molten layer of slag on the combustion chamber wall. Cyclone boilers are high-temperature, wet-bottom type systems.

Stoker-fired systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications. Most packaged stoker units designed for coal firing are small and can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. Underfeed stokers are generally either the horizontal-feed, side-ash-discharge type or the gravity-feed, rear-ash-discharge type. An overfeed stoker uses a moving grate assembly in which coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. In a spreader stoker, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, and air flow velocity. Generally, fuels with finer size distributions, higher volatile matter contents, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.

FBCs, while not constituting a significant percentage of the total boiler population, have nonetheless gained popularity in the last decade, and today generate steam for industries, cogenerators, independent power producers, and utilities. There are two major categories of FBC systems: (1) atmospheric, operating at or near ambient pressures, and (2) pressurized, operating from 4 to 30 atmospheres (60 to 450 pounds per square inch gauge). At this time, atmospheric FBCs are more advanced (or commercialized) than pressurized FBCs. The two principal types of atmospheric FBCs are bubbling bed and circulating bed. The feature that varies most fundamentally between these two types is the fluidization velocity. In the bubbling bed design, the fluidation velocity is relatively low in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ high fluidization velocities to promote the carryover or circulation of the solids. High-temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.

Small, coal-fired boilers and furnaces are found in industrial, commercial, institutional, or residential applications and are sometimes capable of being hand-fired. The most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox. Cast iron boilers are also sometimes available as coal-fired units in a handfed configuration. The HRT boilers are generally fired with gas or oil instead of coal. The boiler and furnace are contained in the same shell in a Scotch or shell boiler. Vertical firetube boilers are typically small singlepass units in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. A firebox boiler is constructed with an internal steel-encased, water-jacketed firebox. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers and employ mechanical stokers or are hand-fired.

1.1.3 Emissions[4]

Emissions from coal combustion depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance. The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Some unburned combustibles, including carbon monoxide (CO) and numerous organic compounds, are generally emitted even under proper boiler operating conditions.

1.1.3.1 Particulate Matter[4] -

PM composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment, and coal properties. Uncontrolled PM emissions from coal-fired boilers include the ash from combustion of the fuel as well as unburned carbon resulting from incomplete combustion. In pulverized coal systems, combustion is almost complete; thus, the emitted PM is primarily composed of inorganic ash residues.

Coal ash may either settle out in the boiler (bottom ash) or entrained in the flue gas (fly ash). The distribution of ash between the bottom ash and fly ash fractions directly affects the PM emission rate and depends on the boiler firing method and furnace type (wet or dry bottom). Boiler load also affects the PM emissions as decreasing load tends to reduce PM emissions. However, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

Soot blowing is also a source of intermittent PM emissions in coal-fired boilers. Steam soot and air soot blowing is periodically used to dislodge ash from heat transfer surfaces in the furnace, convective section, economizer, and air preheater.

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particles that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling train. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

1.1.3.2 Sulfur Oxides[4] -

Gaseous SO_x from coal combustion are primarily sulfur dioxide (SO_2), with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash.

1.1.3.3 Nitrogen Oxides[5-6] -

NO_x emissions from coal combustion are primarily nitric oxide (NO), with only a few volume percent as nitrogen dioxide (NO_2). Nitrous oxide (N_2O) is also emitted at a few parts per million. NO_x formation results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time.[7] Cyclone boilers typically have high conversion of nitrogen to NO_x Typically, only 20 to 60 percent of the fuel nitrogen is converted to NO_x. Bituminous and subbituminous coals usually contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion.

1.1.3.4 Carbon Monoxide -

The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces typically emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors. Combustion modification techniques and equipment used to reduce NO_x can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed.

1.1.3.5 Organic Compounds -

As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas.

Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). [8,9]

Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). Polycyclic organic matter is more prevalent in the emissions from coal combustion because of the more complex structure of coal.

1.1.3.6 Trace Metals-

Trace metals are also emitted during coal combustion. The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the metal itself;
- the concentration of the metal in the coal;
- the combustion conditions; and

- the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals become concentrated in certain particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not.[10] Various classification schemes have been developed to describe this partitioning behavior.[10-12] These classification schemes generally distinguish between:

- Class 1: Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.

- Class 2: Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.

- Class 3: Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 metals is directly related to control of total particulate matter emissions, while control of Class 2 metals depends on collection of fine particulate. Because of variability in particulate control device efficiencies, emission rates of these metals can vary substantially. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.1.3.7 Acid Gases-

In addition to SO_2 and NO_x emissions, combustion of coal also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

1.1.3.8 Fugitive Emissions -

Fugitive emissions are defined as pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer, or storage. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during fly ash transfer operations from silos to trucks or rail cars.

1.1.3.9 Greenhouse Gases[13-18] -

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during coal combustion. Nearly all of the fuel carbon (99 percent) in coal is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is entrained in bottom ash. CO_2 emissions for coal vary with carbon content, and carbon content varies between the classes of bituminous and subbituminous coals. Further, carbon content also varies within each class of coal based on the geographical location of the mine.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1575°F) and excess air is kept to a minimum (less than 1 percent). N_2O emissions for coal combustion are not significant except for fluidized bed combustion (FBC), where the emissions are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed.

Methane emissions vary with the type of coal being fired and firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.1.4 Controls[4]

Control techniques for criteria pollutants from coal combustion may be classified into three broad categories: fuel treatment/substitution, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel treatment primarily reduces SO_2 and includes coal cleaning using physical, chemical, or biological processes; fuel substitution involves burning a cleaner fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control employs a device after the combustion of the fuel and is applied to control emissions of PM, SO_2 , and NO_x for coal combustion.

1.1.4.1 Particulate Matter Control[4] -

The principal control techniques for PM are combustion modifications (applicable to small stoker-fired boilers) and postcombustion methods (applicable to most boiler types and sizes). Uncontrolled PM emissions from small stoker-fired and hand-feed combustion sources can be minimized by employing good combustion practices such as operating within the recommended load ranges, controlling the rate of load changes, and ensuring steady, uniform fuel feed. Proper design and operation of the combustion air delivery systems can also minimize PM emissions. The postcombustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more or the following particulate control devices:

- Electrostatic precipitator (ESP),
- Fabric filter (or baghouse),
- Wet scrubber,
- Cyclone or multiclone collector, or
- Side stream separator.

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes and should have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 micrometer) and coarse particles (greater than 10 micrometers). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of fabric filters is dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e. g., structure of fabric, fiber composition, and bag properties). Collection efficiencies of fabric filters can be as high as 99.9 percent.

Wet scrubbers, including venturi and flooded disc scrubbers, tray or tower units, turbulent contact absorbers, or high-pressure spray impingement scrubbers are applicable for PM as well as SO_2 control on coal-fired combustion sources. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range between 95 and 99 percent for a 2-micron particle.

Cyclone separators can be installed singly, in series, or grouped as in a multicyclone or multiclone collector. These devices are referred to as mechanical collectors and are often used as a precollector upstream of an ESP, fabric filter, or wet scrubber so that these devices can be specified for lower particle loadings to reduce capital and/or operating costs. The collection efficiency of a mechanical collector depends strongly on the effective aerodynamic particle diameter. Although these devices will reduce PM emissions from coal combustion, they are relatively ineffective for collection of particles less than 10 micron (PM-10). The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multicyclone and a small pulse-jet baghouse to more efficiently collect small-diameter particles that are difficult to capture by a mechanical collector alone. Most applications to date for side-stream separators have been on small stoker boilers.

Atmospheric fluidized bed combustion (AFBC) boilers may tax conventional particulate control systems. The particulate mass concentration exiting AFBC boilers is typically 2 to 4 times higher than pulverized coal boilers. AFBC particles are also, on average, smaller in size, and irregularly shaped with higher surface area and porosity relative to pulverized coal ashes. The effect is a higher pressure drop. The AFBC ash is more difficult to collect in ESPs than pulverized coal ash because AFBC ash has a higher electrical resistivity and the use of multiclones for recycling, inherent with the AFBC process, tends to reduce exit gas stream particulate size.

1.1.4.2 Sulfur Oxides Control[4] -

Several techniques are used to reduce SO_x emissions from coal combustion. Table 1.1-1 presents the techniques most frequently used. One way is to switch to lower sulfur coals, since SO_x emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur.

Post combustion flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. Particulate reduction of more than 99 percent is possible with wet scrubbers, but fly ash is often collected by upstream ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with FGD process reactions.[18] Also, the volume of scrubber sludge is reduced with separate fly ash removal, and contamination of the reagents and by-products is prevented.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible.

1.1.4.3 Nitrogen Oxide Controls[4] -

Several techniques are used to reduce NO_x emissions from coal combustion. These techniques are summarized in Table 1.1-2. The primary techniques can be classified into one of two fundamentally different methods—combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process, while postcombustion controls reduce NO_x emission after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air (LEA), burners out of service (BOOS), biased burner firing, overfire air (OFA), low NO_x burners (LNBs), and reburn. Postcombustion control methods are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). Combustion and postcombustion controls can be used separately or combined to achieve greater NO_x reduction from fluidized bed combustors in boilers.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. BOOS involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or OFA conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased burner firing involves more fuel-rich firing in the lower rows of burners than in the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. OFA can be applied for various boiler types including tangential and wall-fired, turbo, and stoker boilers and can reduce NO_x by 20 to 30 percent from uncontrolled levels.

LNBs limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone. The unique design of features of an LNB may create (1) a reduced oxygen level in the combustion zone to limit fuel NO_x formation, (2) a reduced flame temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet New Source Performance Standards (NSPS) limits. LNBs can be combined with OFA to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

Reburn is a combustion hardware modification in which the NO_x produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NO_x created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NO_x reduction of 50 to 60 percent from uncontrolled levels may be achieved.

SNCR is a postcombustion technique that involves injecting ammonia (NH_3) or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and then water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. Although there is currently very limited application of SCR in the U.S. on coal-fired boilers, NO_x reductions of 75 to 86 percent have been realized on a few pilot systems.

1.1.5 Emission Factors

Emission factors for SO_x, NO_x, and CO are presented in Table 1.1-3. Tables in this section present emission factors on both a weight basis (lb/ton) and an energy basis (lb/Btu). To convert from lb/ton to lb/MMBtu, divide by a heating value of 26.0 MMBtu/ton. Because of the inherently low NO_X emission characteristics of FBCs and the potential for in-bed SO_2 capture by calcium-based sorbents, uncontrolled emission factors for this source category were not developed in the same sense as with other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline (uncontrolled) if no additional add-on NO_x control system (such as ammonia injection) was operated.

For SO_2 emissions, a correlation was developed from reported data on FBCs to relate SO_2 emissions to the coal sulfur content and the calcium-to-sulfur ratio in the bed.

Filterable particulate matter and particulate matter less than, or equal to, 10 micrometers in diameter (PM-10) emission factors are presented in Table 1.1-4. Condensable particulate matter emission factors are presented in Table 1.1.5. Cumulative particle size distributions and particulate size-specific emission factors are given in Tables 1.1-6, 1.1-7, 1.1-8, 1.1-9, 1.1-10, and 1.1-11. Particulate size-specific emission factors are also presented graphically in Figures 1.1-1, 1.1-2, 1.1-3, 1.1-4, 1.1-5, and 1.1-6.

Controlled emission factors for PCDD/PCDF and PAHs are provided in Tables 1.1-12 and 1.1-13, respectively. Controlled emission factors for other organic compounds are presented in Table 1.1-14. Emission factors for hydrogen chloride and hydrogen fluoride are presented in Table 1.1-15.

Table 1.1-16 presents emission factor equations for nine trace metals from controlled and uncontrolled boilers. Table 1.1-17 presents uncontrolled emission factors for seven of the same metals, along with mercury, POM and formaldehyde. Table 1.1-18 presents controlled emission factors for 13 trace metals and includes the metals found in Tables 1.1-16 and 1.1-17. The emission factor equations in Table 1.1-16 are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate matter emission factors. Because these are the major parameters affecting trace metals emissions from coal combustion, it is recommended that the emission factor equations be used when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant, then the emission factors provided in Table 1.1-17 and 1.1-18 for the pollutant should be used.

Greenhouse gas emission factors, including CH_4, non-methane organic compounds (NMOC), and N_2O are provided in Table 1.1-19. In addition, Table 1.1-20 provides emission factors for CO_2.

1.1.6 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF home page (http://www.epa.gov/ttn/chief/).

Table 1.1-3. EMISSION FACTORS FOR SO_x, NO_x, AND CO FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, wall-fired[f], bituminous Pre-NSPS[g]	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	22	A	0.5	A
PC, dry bottom, wall-fired[f], bituminous Pre-NSPS[g] with low-NO_x burner	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	11	A	0.5	A
PC, dry bottom, wall-fired[f], bituminous NSPS[g]	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	12	A	0.5	A
PC, dry bottom, wall-fired[f], sub-bituminous Pre-NSPS[g]	1-01-002-22 1-02-002-22 1-03-002-22	35S	A	12	C	0.5	A
PC, dry bottom, wall fired[f], sub-bituminous NSPS[g]	1-01-002-22 1-02-002-22 1-03-002-22	35S	A	7.4	A	0.5	A
PC, dry bottom, cell burner[h] fired, bituminous	1-01-002-15	38S	A	31	A	0.5	A
PC, dry bottom, cell burner fired, sub-bituminous	1-01-002-35	35S	A	14	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO$_x$[b]		NO$_x$[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS[g]	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	15	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS[g] with low-NO$_x$ burner	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	9.7	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, NSPS[g]	1-01-002-12 1-02-002-12 1-03-002-16	38S		10	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, Pre-NSPS[g]	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	8.4	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, NSPS[g]	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	7.2	A	0.5	A
PC, wet bottom, wall-fired[f], bituminous, Pre-NSPS[g]	1-01-002-01 1-02-002-01 1-03-002-05	38S	A	31	D	0.5	A
PC, wet bottom, tangentially fired, bituminous, NSPS[g]	1-01-002-11	38S	A	14	E	0.5	A
PC, wet bottom, wall-fired sub-bituminous	1-01-002-21 1-02B002-21 1-03-002-21	35S	A	24	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Cyclone Furnace, bituminous	1-01-002-03 1-02-002-03 1-03-002-03	38S	A	33	A	0.5	A
Cyclone Furnance, sub-bituminous	1-01-002-23 1-02-002-23 1-03-002-23	35S	A	17	C	0.5	A
Spreader stoker, bituminous	1-01-002-04 1-02-002-04 1-03-002-09	38S	B	11	B	5	A
Spreader Stoker, sub-bituminous	1-01-002-24 1-02-002-24 1-03-002-24	35S	B	8.8	B	5	A
Overfeed stoker[i]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Hand-fed units	1-03-002-14	31S	D	9.1	E	275	E

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	C[j]	E	5.0	D	18	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	C[j]	E	15.2	D	18	D

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

[b] Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. For example, if fuel is 1.2% sulfur, then S = 1.2. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 22-23). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

Table 1.1-3. (cont.)

[c] Expressed as NO_2. Generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 6). To express factors as NO, multiply factors by 0.66. All factors represent emissions at baseline operation (i. e., 60 to 110% load and no NO_x control measures).

[d] Nominal values achievable under normal operating conditions. Values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

[e] Emission factors for CO_2 emissions from coal combustion should be calculated using lb CO_2/ton coal = 72.6C, where C is the weight % carbon content of the coal. For example, if carbon content is 85%, then C equals 85.

[f] Wall-fired includes front and rear wall-fired units, as well as opposed wall-fired units.

[g] Pre-NSPS boilers are not subject to any NSPS. NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are boilers constructed after August 17, 1971 and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978 and with a heat input rate greater than 250 MMBtu/hr.

[h] References 24-27.

[i] Includes traveling grate, vibrating grate, and chain grate stokers.

[j] SO_2 emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: lb SO_2/ton coal = $39.6(S)(Ca/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

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Mathematical Corrections to Sansom Exhibit RS-26

	(1)	(1A)	(2A)	(2B)	(3)	(4)	(5)	(6)	(7)	
Year	**#SO2 per MMBtu Bitum.**	**#SO2 per MMBtu Bitum. X .95**	**#SO2 per MMBtu PRB**	**#SO2 per MMBtu PRB x 0.875**	**#SO2 per MMBtu**	**MMBtu x 1000**	**Excess SO2 Tons**	**SO2 Allowance Price $/Ton**	**Excess SO2 Cost ($)**	
2000	1.12	1.064	0.6	0.525	0.54	36,317	9,787	141	1,380,028	
2001	1.11	1.055	0.6	0.525	0.53	35,796	9,477	186	1,762,720	
2002	1.12	1.064	0.6	0.525	0.54	37,753	10,174	152	1,546,514	
2003	1.03	0.979	0.6	0.525	0.45	32,781	7,433	176	1,308,224	
2004	1.04	0.988	0.6	0.525	0.46	37,980	8,792	442	3,886,228	
2005	1.02	0.969	0.6	0.525	0.44	34,347	7,625	906	6,908,281	$16,791,995

EMISSION FACTOR

DOCUMENTATION FOR

AP-42 SECTION 1.1

BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

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April 1993

1. INTRODUCTION

The document, "Compilation of Air Pollutant Emission Factors" (AP-42), has been published by the U.S. Environmental Protection Agency (EPA) since 1972. Supplements to AP-42 have been routinely published to add new emissions source categories and to update existing emission factors. An emission factor is an average value which relates the quantity (weight) of a pollutant emitted to a unit of activity of the source. In some cases, emission factors are presented in terms of an empirical formula to account for source variables. Emission factors are developed from source test data, material balance calculations, and engineering estimates. The uses for the emission factors reported in AP-42 include:

- Estimates of area-wide emissions;
- Emission estimates for a specific facility; and
- Evaluation of emissions relative to ambient air quality.

The EPA routinely updates AP-42 in order to respond to new emission factor needs of State and local air pollution control programs, industry, as well as the Agency itself. Section 1.1 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to bituminous and subbituminous coal combustion in stationary, external equipment.

The purpose of this EFD is to provide background information and to document the procedures used for the revision, update, and addition of emission factors for bituminous and subbituminous coal combustion. The scope of the present AP-42 Section 1.1 update is as follows:

- Update baseline, criteria emission factors with data identified since the prior updates;

- Modify equipment classifications to give separate treatment of tangentially-fired boilers and fluid bed combustors (FBCs);
- Extend emission factors to non-criteria species where data are available for volatile organic compounds (VOC) speciation, trace metals and other air toxics, and greenhouse gases [nitrous oxide (e.g., N_2O), carbon dioxide (CO_2)]; and
- Extend documentation and emission factor development for controlled operation to reflect advances in control development and the increased importance of emission controls for combustion sources.

Data from approximately 20 test reports were used to revise and update emission factors for existing source categories; determine new emission factors for additional non-criteria pollutants; and add FBC units as a new source category.

The update of Section 1.1 of AP-42 began with a review of the existing version of Section 1.1. Spot checks were made on the quality of existing emission factors by recalculating emission factors from selected primary data references contained in the background files. These recalculated emission factors were then compared against those in the existing version of AP-42.

An extensive literature review was undertaken to improve technology descriptions, update usage trends, and collect new test reports for criteria and non-criteria emissions. The new test reports were subjected to data quality review as outlined in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). Test reports containing sufficiently high quality data ratings were combined with existing data to revise emission factors or to produce new emission factors, as appropriate. When sufficient new data were obtained that were of higher quality than existing data, old lower-quality data were removed from the existing emission factor averages. In some cases, data sources and test reports were identified during the literature review but were not received in sufficient time to incorporate into emission factor development. This information has been placed in the background files for use in future updates.

Several new emission factors for non-criteria pollutants have been added. These new emission factors pertain to total organic compounds (TOC), speciated volatile organic compounds (speciated VOC), air toxics, N_2O, CO_2, and fugitive emissions. Additionally, in this revision, the information on control technologies for particulate matter (PM), PM less than 10 microns (PM-10), sulfur oxide (SO_x), and nitrogen oxides (NO_x) emissions has been revised and updated. Add-on controls for non-criteria pollutants are not covered here because these controls have not been demonstrated on commercial scale combustors for this source category. Finally, because fluidized bed combustion of coal is finding increased commercial application in industrial and utility systems, a new source category for this combustion configuration has been added.

Including the introduction (Chapter 1), this EFD contains five chapters. Chapter 2 provides an overall characterization of bituminous and subbituminous coal combustion usage. This includes a breakdown of coal application by industry, an overview of the different source categories, a description of emissions, and a description of the technology used to control emissions resulting from coal combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emissions data reports, and the quality rating system for both emission data and emission factors. Chapter 4 details pollutant emission factor development. It includes the review of specific data sets and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.1. Appendix A provides conversion factors and example calculations for emission factor development from test data. Appendix B contains an example of spot checking data from the fourth edition AP-42 primary references. Appendix C contains a marked-up copy of the 1988 AP-42 Section 1.1 indicating where changes have been made as a result of this update.

4. EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for bituminous and subbituminous coal combustion.

4.1 CRITERIA POLLUTANTS

4.1.1 Review of Previous AP-42 Data

The emission factor documentation files from the prior AP-42 updates of Section 1-1 were obtained and reviewed. The criteria emission factors were developed in 1981 and documented in Reference 1. The emission factors for particle sizing and particulate collection efficiencies by particle size were developed in 1984 in Reference 2. Initially, much of the documentation used in developing these prior emission factors were reviewed. The references included:

- The 61 primary references cited in the 1988 Section 1.1.;
- Secondary references from background files;
- Memoranda and emission factor worksheets from the prior updates.

The references used in developing the prior emissions factors were checked in several cases as a first-level quality check on the documentation. Table 4-1 lists several of the cases where the reference trail was spot checked. Several anomalies regarding reference documentation were revealed, but none which invalidated the quality of the results. A review of the 1988 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was done by selecting primary data references from the background files, reviewing data quality sampling and analytical procedures, determining completeness, and verifying that the site emission factors in the background files could be reconstructed and were accurate. Examples of spot-check data are presented in Appendix A.

Spot checks revealed that, in general, ample A-quality rated data points were available for the criteria pollutants or that most poor quality data had little affect on the published AP-42 emission factors. However, questions regarding the quality of the data used to calculate the emission factors were justified and point to a need to properly review references, assigned data quality ratings, and calculations, when developing improved emission factors for well-defined equipment categories.

4.1.2 Review of New Baseline Data

A total of 60 references were identified and reviewed during the literature search. These references are listed in the checklists added to the background files for this update to AP-42. The original group of 60 documents was reduced to a set of rated references utilizing the criteria outlined in Chapter 3. The following is a discussion of the data contained in each of the rated references.

Reference 3

This report covers the emissions of two hand-feed space heaters tested in cooperation with the Vermont Agency of Environmental Conservation. Oxygen, CO_2 and CO were measured by Orsat from a grab sample collected over the test duration. SO_2 and light hydrocarbons were analyzed from a grab sample in a gas chromatograph. Particulate measurement was made from front half catch of a Modified Method 5 (MM5) sampling train. Hazardous air pollutants (HAPs) were also reported. No original data sheets were found. Coal analysis was reported on a dry basis and higher heating value (HHV) was reported on dry ash free basis. Emissions were calculated in the report (p.15) but appear to be reported incorrectly. Particulate emissions were recalculated using the F-factor in 40 Code of Federal Regulations (CFR) Part 60 Appendix A, EPA Method 19. Data were assigned a rating of C.

Reference 4

This report covers the emissions of one 40,000 lb steam/hr (18,000 kg steam/hr) FBC for long term performance. Data were collected to support NSPS for small boilers. Oxygen, CO_2, SO_2, NO_x, and CO were analyzed by certified continuous emission monitors (CEMs). Test data for the thirty day testing period are presented in the report in molar concentration units. Data from February 28, 1986 were averaged to obtain NO_x and CO emission factors. Sulfur dioxide emissions were controlled by limestone addition to the FBC. No uncontrolled particulate data were found. Data were given a quality rating of B.

Reference 5

This is a compliance test report for PM, SO_2, and NO_x on a 100 MWe tangential-fired boiler for the Nebraska Department of Environmental Control in Lincoln, Nebraska. Particulate was sampled after an ESP and was not useful for uncontrolled emissions. Sampling was performed by EPA Methods 6 and 7. Emissions were given in lb/million Btu (MMBTU). Data were given a quality rating of A.

Reference 6

This is a compliance test report for SO_2 on a 145 MWe PC-fired unit manufactured by Riley Stoker Corporation. Sampling was performed by EPA Method 6 after an ESP. Emissions were given in lb/MMBTU. Data were given a quality rating of A.

Reference 7

This is a test report for short-term testing on seven separate boilers with different configurations over a five-day period. Emphasis of the report is on specific organic compounds; however, CEMs were used to monitor O_2, CO, and total hydrocarbons (THC) during test conditions. There was inadequate information in this report to determine reporting units and measurement method for THC. No CEM specifications or calibration procedures were found but method is fairly well established. Some sampling sites were located after ESPs but this was not expected to significantly alter CO emissions. Sulfur dioxide and NO_x data were available for one of the plants tested via plant-installed CEMs after an ESP. Data were given a quality rating of B.

Reference 8

This is a compliance test report for the Kansas Board of Public Utilities for two coal-fired cyclone boilers. Testing was done by EPA Method 6. Raw data were available but titrations were not checked. Sampling was conducted at the stack after a baghouse and ESP, respectively. A summary table listed emissions in lb/MMBTU based on Tabulated F-factor in 40 CFR Part 60 Appendix 19. Data were given a quality rating of A.

Reference 9

This is a compliance test report for the Kansas Board of Public Utilities on a PC-fired boiler. Insufficient detail for the unit was given to specify firing configuration; however, this information is not necessary for emission factor development at this time. Samples were taken both before and after an ESP to show removal efficiency. Unit was operating at nominally 90 percent of nameplate rating (145 MWe). Raw data were available. Emissions were presented in lb/MMBTU based on an F-factor derived from the fuel analysis. Data were given a quality rating of A.

Reference 10

This report is an EPA/Office of Air Quality Planning and Standards (OAQPS)/Emission Measurements Branch (EMB) document describing a test of Tennessee Eastman's Boiler 24 in Kingsport, Tennessee, in support of the industrial boiler NSPS. The tests were conducted to determine the effects of boiler load, O_2 and preheat on NO_x emissions. Continuous monitors were used to measure NO_x, CO and O_2; NO_x was also measured using EPA Method 7. Comparison of the two NO_x methods was acceptable and the average was used for emission factor calculation. Five of the nine runs were conducted at acceptable boiler loads (> 70 percent). The remaining runs at low load (approximately 55 percent) indicated a 20 percent reduction in NO_x emissions with little effect on CO levels. An A rating has been assigned to this data.

Reference 11

This report is an EPA/OAQPS/EMB document describing a test of an industrial boiler with stoker gas recirculation (SGR) at Upjohn Company's Kalamazoo, MI, facility. These tests were also in support of the industrial boiler NSPS. The effects of boiler load, O_2 and SGR on NO_x emissions were measured. Continuous monitors were used to measure NO_x, CO, and O_2. Nine of the ten runs were made at boiler loads of 75 to 100 percent with O_2 levels between 3.2 and 8.0 percent. These data were used in the emission factor calculations. The remaining run at 50-percent load showed no noted effect on NO_x or CO levels. An A rating has been assigned to this data.

Reference 12

This report is an EPA/OAQPS/EMB report describing a test of an industrial spreader stoker at the Burlington Industries facility in Clarksville, VA. These tests were conducted in support of the industrial boiler NSPS for PM. Nine runs were performed at various boiler loads using a slight variation of EPA Method 5 for the particulate measurements. The modification to the sampling method was in heating the filter box to 160°C (320°F). In a previous report comparing results using this variation to standard Method 5 data, this method produced particulate catches of 94 to 100 percent of Method 5 results. Five of the nine runs were used in the emission factor calculations. Three of the remaining runs were at one-third boiler load and one run exceeded the acceptable percent-isokinetic standard. A B rating was assigned to this data because of the method modification and wide variation in results.

Reference 13

Contains SO_2 and NO_x summary data for the Tennessee Valley Authority's (TVA) bubbling bed FBC (with and without fly ash reinjection) and Batelle's circulating bed FBC. Original test reports are referenced in the document and should be obtained in order to upgrade quality rating. Data were assigned a quality rating of D.

4.1.3 Compilation of Baseline Emission Factors

The references described above were used in updating the uncontrolled (baseline) emission factors for criteria pollutants. Computerized spreadsheets were set up to calculate new data points from the information contained in these references. Sections of the spreadsheets, pertaining to specific pollutants are shown as Tables 4-2 through 4-8.

The new data points were combined with the 1988 AP-42 Section 1.1 data points retained from spot checking to develop new emission factors. The various formulae and conversion factors used in the spreadsheet programs and in the calculation of new emission factors are shown in Appendix B.

4.1.3.1 SO_2 Emission Factors. The new SO_2 baseline data are summarized in Table 4-2. The following new data points were added to the emission factor database:

- Cyclone furnace: 3 points
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Pulverized coal, dry bottom, wall fired: 1 point
- Handfeed: 1 point
- Bubbling bed FBC: 6 points
- Circulating bed FBC: 1 point

The spot checks revealed only minor anomalies in the 1988 AP-42 emission factor calculations. One test report[14] appeared to have a discrepancy in the fuel analysis procedures. For the "ALMA" site, the facility data point was developed from the fuel sulfur content measured on a dried and pulverized (as-fired) basis, but with the as-received HHV. However, making this correction only changes the data point from 33S to 33.7S, where S is the percent sulfur in the fuel. Also, for the subbituminous coal testing at the same site, the coal sample averages did not match the emissions average periods. Again, however, making these corrections did not effectively change the site data point. Therefore, all previous SO_2 emission factor background data were retained in the current update effort.

For bituminous coal firing, three new data points were added for cyclone boilers, and one data point each was added for PC wall-fired and tangential-fired boilers. Of the three cyclone boiler tests, data from two tests were rated E because the calculated emission factors were above the theoretical maximum value of 40S; the remaining cyclone boiler test produced a B-rated emission factor of 31.5S. Test data from the two PC-fired boilers were rated A and B. The average of the emission factors from these two tests was 38.1S. These data, when combined with a 1984 review[89] of the 1982 emission factor development effort and data base, justify a revision of the SO_x emission factor from 39S to 38S for PC-fired, cyclone, spreader stoker, and overfeed stoker boilers.

One new data point from Reference 1 was obtained for a small 2.9 KW (10,000 Btu/hr) hand-fired unit. However, this data point was assigned a C rating and, at a value of 52.4S, was significantly different from the existing average emission factor of 31S for underfeed and hand-fired units. Therefore, the existing AP-42 emission factor was retained.

No new data for subbituminous coal firing were identified during this update. Therefore, the existing emission factor of 35S for PC, cyclone, and spreader and overfeed stokers was retained.

New emission factors were developed for FBCs which have been included in this update of AP-42 as a new source category. As discussed in Chapter 2, a correlation was developed with the coal sulfur content and the calcium-to-sulfur ratio in the bed. The data obtained from the FBC test reports are plotted against calcium-to-sulfur ratio (Ca/S) in Figure 4-1.

Four data points were obtained from Reference 4 showing the effect of available Ca/S ratio on SO_2 emissions. Reference 4 data were given an A rating. The FBC in Reference 4 is a bubbling bed FBC incorporating reinjection of fly ash captured in the first stage cyclone. Fly ash reinjection results increase in higher calcium utilization and lower SO_2 emissions.

Reference 13 presented summary data from both bubbling and circulating bed FBCs. These data were given D ratings because the report lacked sufficient background data to fully evaluate the source operation and test methodology. However, when plotted on Figure 4-1, the data point from the bubbling bed unit with fly ash reinjection matched the data from the similar FBC in Reference 2. Because of the limited number of FBC test data reports which were obtained for this update of AP-42, all these data points were used in developing the SO_2 emission factor correlation. The data from the bubbling bed unit without fly ash reinjection do not match the reinjection data and therefore were not considered in the correlation. Also, the data point from the circulating bed FBC plotted on Figure 4-1 follows the same trend as the bubbling bed units with fly ash reinjection. This behavior is not surprising because circulating bed units are essentially an extension of bubbling bed technology but with higher fluidizing velocities and a high ratio of fly ash reinjection.

All data shown in Figure 4-1 from the bubbling bed units with fly ash reinjection and the circulating bed unit were curve-fit to develop a correlation for the emission factor. The best-fit equation reflecting the SO_2 emissions performance of FBCs was:

$$\frac{lb\ SO_2}{ton\ coal} = 39.6(S)\left(\frac{Ca}{S}\right)^{-1.9}$$

where S is the weight percent sulfur in the coal and Ca/S is the molar calcium-to-sulfur ratio in the bed. This correlation was used for the SO_2 emission factor for both bubbling bed and circulating bed FBCs. An emission factor quality rating of D was given for bubbling bed units because of the limited number of facilities used to obtain the test data. An emission factor quality rating of E was given to the circulating bed units.

When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate FBC SO_2 emissions. In this case, the emission factor quality ratings should be E for both bubbling and circulating bed units.

4.1.3.2 <u>NO_x Emission Factors</u>. The new NO_x baseline data are summarized in Table 4-3. The following new data points were added to the emission factor database:

- Cyclone furnace: 1 point
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Handfed: 1 point

TABLE 4-1. BACKGROUND DOCUMENT CHECK

Pollutant	Configuration	References cited in 1988 AP-42 Section 1.1	Site No.	Emission factor	References spot checked
PM	PC dry bottom	15, 16, 17, 19, 21 EPA-650/7-80-171 (20)	17	10A	15, 17
PM	Handfired units				49, 50
SO_2	Bituminous emission-based	9, 16, 17, 18, 19, 21, 31, 37, 39, 41, 42, 43, 46, 51, 52, 55	49	39S	17, 18
SO_2	Bituminous retention-based	17, 18, 32, 33, 34, 35, 41, 42, 44, 45	11	39S	18
SO_2	Subbituminous	9, 17, 31, 53, 54	15	35S	17
NO_x	PC dry bottom	11, 14, 16, 17, 21, 56	28	21	17
NO_x	Handfired units				50
CO	Handfired units				50
VOC	PC dry bottom	58	17	.07	58
VOC	PC wet bottom				58
VOC	Cyclone, spreader stoker, overfeed stoker				58
VOC	Underfeed stoker				58
VOC	Handfired units				58, 50
CH_4	PC, Cyclone, Spreader Stoker, Overfeed Stoker	58	16	.03	58
CH_4	Underfeed Stoker				58
CH_4	Handfired Units				58, 50

A = weight percent ash in fuel
S = weight percent sulfur in fuel

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

					Fuel		Operation			SO_2 Emissions,			FBC control efficiency	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	Capacity	Units	Load Factor	ppm	lb/MMBtu	(lb/ton)/S	Ca/S, mole/mole	SO2, %
8	E	Cyclone	KAW Unit 1	3B	11496	2.68	400000	lb/hr	0.96		5.0700	43.50		
8	E	Cyclone	KAW Unit 1	1B	11629	2.63	400000	lb/hr	0.96		4.9700	43.95		
8	E	Cyclone	KAW Unit 1	3A	11496	2.68	400000	lb/hr	0.96		5.0700	43.50		
8	E	Cyclone	KAW Unit 1	2B	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
8	E	Cyclone	KAW Unit 1	1A	11629	2.63	400000	lb/hr	0.96		5.2100	46.07		
8	E	Cyclone	KAW Unit 1	2A	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
												44.65		
7	B	Cyclone	Plant 5	3	12121	1.81	584	MW	1.01	980.0	2.4880	33.32		
7	B	Cyclone	Plant 5	1	12121	1.81	584	MW	1.01	840.0	2.2153	29.67		
7	B	Cyclone	Plant 5	2	12121	1.81	584	MW	1.00	950.0	2.5064	33.56		
7	B	Cyclone	Plant 5	4	12121	1.81	584	MW	0.79	800.0	2.1263	28.48		
7	B	Cyclone	Plant 5	5	12121	1.81	584	MW	0.83	950.0	2.4119	32.30		
												31.47		
8	E	Cyclone	Quindaro #1	2A	11376	2.81	625000	lb/hr	0.74		5.7000	46.15		
8	E	Cyclone	Quindaro #1	2B	11376	2.81	625000	lb/hr	0.74		5.6800	45.99		
8	E	Cyclone	Quindaro #1	3A	11387	1.93	625000	lb/hr	0.75		5.6500	66.67		
8	E	Cyclone	Quindaro #1	1B	11309	2.76	625000	lb/hr	0.74		5.7200	46.87		
8	E	Cyclone	Quindaro #1	3B	11387	1.93	625000	lb/hr	0.75		5.7400	67.73		
8	E	Cyclone	Quindaro #1	1A	11309	2.76	625000	lb/hr	0.74		5.5400	45.40		
												53.14		
4	A	FBC-BB	Summerside	AVE	11770	5.96	50	MMBTU/hr	0.72		2.0300	8.02^a	2.70	0.73
4	A	FBC-BB	Summerside	AVE	11510	5.92	50	MMBTU/hr	0.73		0.4800	1.87^a	4.10	0.95
4	A	FBC-BB	Summerside	AVE	11760	5.90	50	MMBTU/hr	0.73	212.3	0.6981	2.78^a	3.40	0.93

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

					Fuel		Operation			SO_2 Emissions,			FBC control efficiency	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	Capacity	Units	Load Factor	ppm	lb/MMBtu	(lb/ton)/S	Ca/S, mole/mole	SO2, %
4	A	FBC-BB	Summerside	AVE	11430	5.20	50	MMBTU/hr	0.66		0.4000	1.76^{a}	6.00	0.96
13	D	FBC-BB	TVA 20MWe	2	13000	3.84	228	MMBTU/hr	0.66		0.1400	0.95^{a}	3.00	0.98
13	D	FBC-BB	TVA 20MWe	1	13000	4.46	228	MMBTU/hr	0.66		0.8600	5.61^{a}	3.00	0.87
13	D	FBC-C	BATTELLE	1	13000	1.50	50	MMBTU/hr			0.1200	2.08	4.50	0.95
3	C	Hand-Fed		Coal Stove	14118	0.77	0.01	MMBTU/hr		208.0	0.8957	32.69		
3	E	Hand-Fed		Modified Wood Stove	13421	0.79	0.01	MMBTU/hr		430.0	2.1201	72.07		
6	A	PC-fired	Quindaro #2	2B	11201	1.70	145	MW	0.83		2.9700	39.14		
6	A	PC-fired	Quindaro #2	2A	11201	1.70	145	MW	0.83		2.8600	37.69		
6	A	PC-fired	Quindaro #2	4A	11304	1.72	145	MW	0.83		2.8500	37.46		
6	A	PC-fired	Quindaro #2	4B	11304	1.72	145	MW	0.83		2.8900	37.99		
6	A	PC-fired	Quindaro #2	3A	11185	1.77	145	MW	0.83		2.9700	37.54		
6	A	PC-fired	Quindaro #2	1A	11230	1.80	145	MW	0.83		2.8100	35.06		
6	A	PC-fired	Quindaro #2	3B	11185	1.77	145	MW	0.83		2.9400	37.16		
												37.43		
5	A	PC-TFired		3	8104	0.44	100	MW	1.02		1.1000	40.52		
5	A	PC-TFired		2	8104	0.44	100	MW	1.02		1.0390	38.27		
5	A	PC-TFired		1	8104	0.44	100	MW	1.02		1.0200	37.57		
												38.79		

[a] SO_2 emissions controlled by the addition of sorbents (e.g., limestone) to the FBC.
S = weight percent sulfur in fuel

APPENDIX A

BACKGROUND FILE DATA SPOT CHECK SUMMARY

A review of the 1988 AP-42 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was sone by selecting primary data references from the background file, reviewing data quality sampling and analytical procedures, determining completeness, and verifyuing that the site emission factors in the background files could be reconstructed and were accurate. The results of these spot checks are summarized below; the reference numbers correspond to the 1988 AP-42 Section 1.1 reference list. Example spot check data are presented in Table A-1.

Reference 15

Contains six data points. States in the paper that a sampling was only for comparative purposes and emission shouldn't be taken as absolute. Couldn't get all representative sampling locations due to obstruction or bends. Able to recreate "background" data values in histogram.

Reference 17

Checked "ALMA" site. Particulate tests done with bituminous and subbituminous coal. Appears two values were averaged and entered in histogram twice.

Sulfur dioxide data are questionable because sulfur analysis was taken from samples after the blower but HHV is baseed on "as received" coal. Need to eliminate some anomalous data points. Requires minor adjustment to SO_2 histograms. Chedked "ALMA" site. Appears that emission factor was calculated from parametric test midifying combustion air. Normal operation should be used for emission factor indicating a revision of the histogram and emission factor.

Reference 18

Sample train was an unproven Method 5 midified to collect HAPs from utility boilers. Sulfur dioxide based on sulfur retention in bottom ash was acceptable. Carbon monoxide data were not of good quality but hadd not been used in the previous AP-42 update. Particulate data (uncontrolled) were colleced in an improper sampling location with poor flow distribution and significant swirl because it was only two diameters from the inlet breaching. Data should be rated as poor quality but calculated emission factor (96A) is very close to the AP-42 published average. therefore, inclusion or exclusion is not significant.

Reference 23

Particulate measurements were nade using currently unapproved APCO and ASME methods. Correlation between tow methods was not good; test conditions, methodologies, and data collected were not well-documented (no raw data sheets). Data quality should be reated no better than C. Calculations were correct.

INTRODUCTION

Emission factors and emission inventories have long been fundamental tools for air quality management. Emission estimates are important for developing emission control strategies, determining applicability of permitting and control programs, ascertaining the effects of sources and appropriate mitigation strategies, and a number of other related applications by an array of users, including federal, state, and local agencies, consultants, and industry. Data from source-specific emission tests or continuous emission monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions. However, test data from individual sources are not always available and, even then, they may not reflect the variability of actual emissions over time. Thus, emission factors are frequently the best or only method available for estimating emissions, in spite of their limitations.

The passage of the *Clean Air Act Amendments Of 1990* (*CAAA*) and the *Emergency Planning And Community Right-To-Know Act* (*EPCRA*) of 1986 has increased the need for both criteria and Hazardous air pollutant (HAP) emission factors and inventories. The Emission Factor And Inventory Group (EFIG), in the U. S. Environmental Protection Agency's (EPA) Office Of Air Quality Planning And Standards (OAQPS), develops and maintains emission estimating tools to support the many activities mentioned above. The AP-42 series is the principal means by which EFIG can document its emission factors. These factors are cited in numerous other EPA publications and electronic data bases, but without the process details and supporting reference material provided in AP-42.

What Is An AP-42 Emission Factor?

An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). Such factors facilitate estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i. e., a population average).

The general equation for emission estimation is:

$$E = A \times EF \times (1 - ER/100)$$

where:

E = emissions,
A = activity rate,
EF = emission factor, and
ER = overall emission reduction efficiency, %.

ER is further defined as the product of the control device destruction or removal efficiency and the capture efficiency of the control system. When estimating emissions for a long time period

(e. g., one year), both the device and the capture efficiency terms should account for upset periods as well as routine operations.

Emission factor ratings in AP-42 (discussed below) provide indications of the robustness, or appropriateness, of emission factors for estimating average emissions for a source activity. Usually, data are insufficient to indicate the influence of various process parameters such as temperature and reactant concentrations. For a few cases, however, such as in estimating emissions from petroleum storage tanks, this document contains empirical formulae (or emission models) that relate emissions to variables such as tank diameter, liquid temperature, and wind velocity. Emission factor formulae that account for the influence of such variables tend to yield more realistic estimates than would factors that do not consider those parameters.

The extent of completeness and detail of the emissions information in AP-42 is determined by the information available from published references. Emissions from some processes are better documented than others. For example, several emission factors may be listed for the production of one substance: one factor for each of a number of steps in the production process such as neutralization, drying, distillation, and other operations. However, because of less extensive information, only one emission factor may be given for production facility releases for another substance, though emissions are probably produced during several intermediate steps. There may be more than one emission factor for the production of a certain substance because differing production processes may exist, or because different control devices may be used. Therefore, it is necessary to look at more than just the emission factor for a particular application and to observe details in the text and in table footnotes.

The fact that an emission factor for a pollutant or process is not available from EPA does not imply that the Agency believes the source does not emit that pollutant or that the source should not be inventoried, but it is only that EPA does not have enough data to provide any advice.

Uses Of Emission Factors

Emission factors may be appropriate to use in a number of situations such as making source-specific emission estimates for areawide inventories. These inventories have many purposes including ambient dispersion modeling and analysis, control strategy development, and in screening sources for compliance investigations. Emission factor use may also be appropriate in some permitting applications, such as in applicability determinations and in establishing operating permit fees.

Emission factors in AP-42 are neither EPA-recommended emission limits (e. g., best available control technology or BACT, or lowest achievable emission rate or LAER) nor standards (e. g., National Emission Standard for Hazardous Air Pollutants or NESHAP, or New Source Performance Standards or NSPS). Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA. Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance.

Also, for some sources, emission factors may be presented for facilities having air pollution control equipment in place. Factors noted as being influenced by control technology do not necessarily reflect the best available or state-of-the-art controls, but rather reflect the level of (typical) control for which data were available at the time the information was published. Sources often are tested more frequently when they are new and when they are believed to be operating properly, and either situation may bias the results.

As stated, source-specific tests or continuous emission monitors can determine the actual pollutant contribution from an existing source better than can emission factors. Even then, the results will be applicable only to the conditions existing at the time of the testing or monitoring. To provide the best estimate of longer-term (e. g., yearly or typical day) emissions, these conditions should be representative of the source's routine operations.

A material balance approach also may provide reliable average emission estimates for specific sources. For some sources, a material balance may provide a better estimate of emissions than emission tests would. In general, material balances are appropriate for use in situations where a high percentage of material is lost to the atmosphere (e. g., sulfur in fuel, or solvent loss in an uncontrolled coating process.) In contrast, material balances may be inappropriate where material is consumed or chemically combined in the process, or where losses to the atmosphere are a small portion of the total process throughput. As the term implies, one needs to account for all the materials going into and coming out of the process for such an emission estimation to be credible.

If representative source-specific data cannot be obtained, emissions information from equipment vendors, particularly emission performance guarantees or actual test data from similar equipment, is a better source of information for permitting decisions than an AP-42 emission factor. When such information is not available, use of emission factors may be necessary as a last resort. Whenever factors are used, one should be aware of their limitations in accurately representing a particular facility, and the risks of using emission factors in such situations should be evaluated against the costs of further testing or analyses.

Figure 1 depicts various approaches to emission estimation, in a hierarchy of requirements and levels of sophistication, that one should consider when analyzing the tradeoffs between cost of the estimates and the quality of the resulting estimates. Where risks of either adverse environmental effects or adverse regulatory outcomes are high, more sophisticated and more costly emission determination methods may be necessary. Where the risks of using a poor estimate are low, and the costs of more extensive methods are unattractive, then less expensive estimation methods such as emission factors and emission models may be both satisfactory and appropriate. In cases where no emission factors are available but adverse risk is low, it may even be acceptable to apply factors from similar source categories using engineering judgment. Selecting the method to be used to estimate source-specific emissions may warrant a case-by-case analysis considering the costs and risks in the specific situation. All sources and regulatory agencies should be aware of these risks and costs and should assess them accordingly.

Variability Of Emissions

Average emissions differ significantly from source to source and, therefore, emission factors frequently may not provide adequate estimates of the average emissions for a specific source. The extent of between-source variability that exists, even among similar individual sources, can be large depending on process, control system, and pollutant. Although the causes of this variability are considered in emission factor development, this type of information is seldom included in emission test reports used to develop AP-42 factors. As a result, some emission factors are derived from tests that may vary by an order of magnitude or more. Even when the major process variables are accounted for, the emission factors developed may be the result of averaging source tests that differ by factors of five or more.

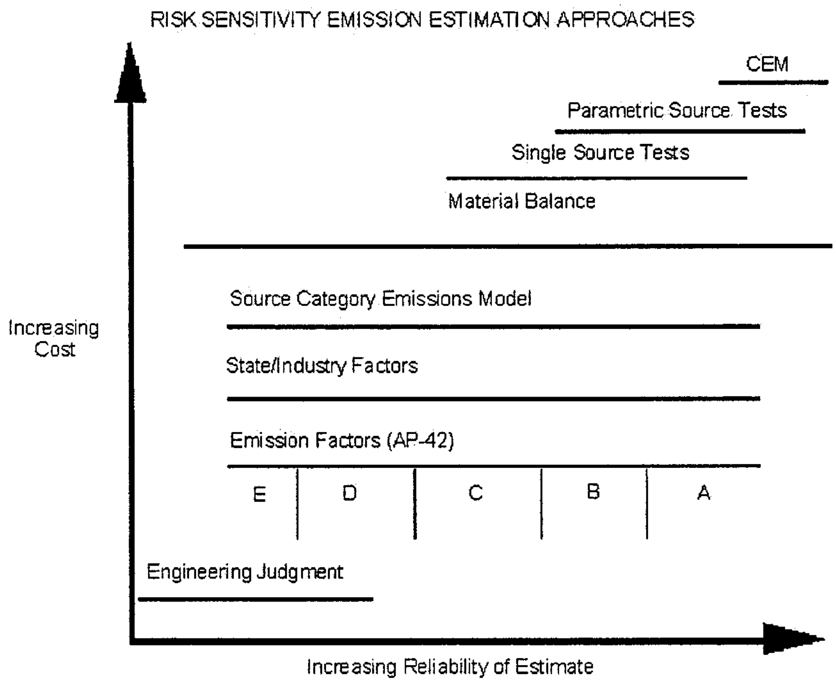

Figure 1. Approach to emission estimation.

Air pollution control devices also may cause differing emission characteristics. The design criteria of air pollution control equipment affect the resulting emissions. Design criteria include such items as the type of wet scrubber used, the pressure drop across a scrubber, the plate area of an electrostatic precipitator, and the alkali feed rate to an acid gas scrubber. Often, design criteria are not included in emission test reports (at least not in a form conducive to detailed analysis of how varying process parameters can affect emissions) and therefore may not be accounted for in the resulting factors.

Before simply applying AP-42 emission factors to predict emissions from new or proposed sources, or to make other source-specific emission assessments, the user should review the latest literature and technology to be aware of circumstances that might cause such sources to exhibit emission characteristics different from those of other, typical existing sources. Care should be taken to assure that the subject source type and design, controls, and raw material input are those of the source(s) analyzed to produce the emission factor. This fact should be considered, as well as the age of the information and the user's knowledge of technology advances.

Estimates of short-term or peak (e. g., daily or hourly) emissions for specific sources are often needed for regulatory purposes. Using emission factors to estimate short-term emissions will add further uncertainty to the emission estimate. Short-term emissions from a single specific source often vary significantly with time (i. e., within-source variability) because of fluctuations in process operating conditions, control device operating conditions, raw materials, ambient conditions, and other such factors. Emission factors generally are developed to represent long-term average emissions, so testing is usually conducted at normal operating conditions. Parameters that can cause short-term fluctuations in emissions are generally avoided in testing and are not taken into account in test evaluation. Thus, using emission factors to estimate short-term emissions will cause even greater uncertainty. The AP-42 user should be aware of this limitation and should evaluate the possible effects on the particular application.

To assess within-source variability and the range of short-term emissions from a source, one needs either a number of tests performed over an extended period of time or continuous monitoring data from an individual source. Generally, material balance data are not likely to be sufficient for assessing short-term emission variability because the accuracy of a material balance is greatly reduced for shorter time intervals. In fact, one of the advantages of a material balance approach is that it averages out all of the short-term fluctuations to provide a good long-term average.

Pollutant Terminology And Conventions

The need for clearly and precisely defined terms in AP-42 should be evident to all. The factors in this document represent units of pollutants (or for ozone, precursors) for which there are National Ambient Air Quality Standards (NAAQS). These are often referred to as "criteria" pollutants. Factors may be presented also for HAPs ("hazardous" air pollutants designated in the *Clean Air Act*) and for other "regulated" and unregulated air pollutants. If the pollutants are organic compounds or particulate matter, additional species or analytical information may be needed for specific applications. It is often the case that the ideal measure of a pollutant for a specific application may not be available, or even possible, because of test method or data limitations, costs, or other problems. When such qualifications exist in AP-42, they will be noted in the document. If a pollutant is not mentioned in AP-42, that does not necessarily mean that the pollutant is not emitted.

Many pollutants are defined by their chemical names, which often may have synonyms and trade names. Trade names are often given to mixtures to obscure proprietary information, and the same components may have several trade names. For assurance of the use of the proper chemical identification, the Chemical Abstract Service (CAS) number for the chemical should be consulted along with the list of synonyms. Some pollutants, however, follow particular conventions when used in air quality management practices. The pollutant terminology and conventions currently used in AP-42 are discussed below.

Particulate Matter -

Terms commonly associated with the general pollutant, "particulate matter" (PM), include PM-10, PM-X, total particulate, total suspended particulate (TSP), primary particulate, secondary particulate, filterable particulate, and condensable particulate. TSP consists of matter emitted from sources as solid, liquid, and vapor forms, but existing in the ambient air as particulate solids or liquids. Primary particulate matter includes that solid, liquid, or gaseous material at the pressure and temperature in the process or stack that would be expected to become a particulate at ambient temperature and pressure. AP-42 contains emission factors for pollutants that are expected to be primary particulate matter. Primary particulate matter includes matter that may eventually revert to a gaseous condition in the ambient air, but it does not include secondary particulate matter. Secondary particulate matter is gaseous matter that may eventually convert to particulate matter through atmospheric chemical reactions. The term "total particulate" is used in AP-42 only to describe the emissions that are primary particulate matter. The term "Total PM-X" is used in AP-42 to describe those emissions expected to become primary particulate matter smaller than "X" micrometers (μm) in aerodynamic diameter. For example, "PM-10" is emitted particulate matter less than 10 μm in diameter. In AP-42, "Total Particulate" and "Total PM-X" may be divided into "Filterable Particulate", "Filterable PM-X", "Condensable Organic Particulate", and "Condensable Inorganic Particulate". The filterable portions include that material that is smaller than the stated size and is collected on the filter of the particulate sampling train.

Unless noted, it is reasonable to assume that the emission factors in AP-42 for processes that operate above ambient temperatures are for filterable particulate, as defined by EPA Method 5 or its equivalent (a filter temperature of 121°C (250°F). The condensable portions of the particulate matter consist of vaporous matter at the filter temperature that is collected in the sampling train impingers and is analyzed by EPA Method 202 or its equivalent. AP-42 follows conventions in attempts to define Total Particulate and its subcomponents, filterable particulate, condensable particulate, and PM-10 and their interrelationships. Because of test method and data limitations, this attempt may not always be successful, and some sources may not generate such components.

Because emission factors in AP-42 are usually based upon the results of emission test reports, and because Method 202 was only recently developed, AP-42 emission factors often may adequately characterize only in-stack filterable PM-10. Recent parts of the AP-42 series have used a clearer nomenclature for the various particulate fractions. It is reasonable to assume that, where AP-42 does not define the components of particulate clearly and specifically, the PM-10 factor includes only the filterable portion of the total PM-10. Therefore, an evaluation of potential condensable particulate emissions should be based upon additional data or engineering judgment.

As an additional convention, users should note that many hazardous or toxic compounds may be emitted in particulate form. In such cases, AP-42 factors for particulate matter represent the total, and factors for such compounds or elements are reported as mass of that material.

Organic Compounds -

Precursors of the criteria pollutant "ozone" include organic compounds. "Volatile organic compounds" (VOC) are required in a State Implementation Plan (SIP) emission inventory. VOCs have been defined by EPA (40 CFR 51.100, February 3, 1992) as "any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric chemical reactions". There are a number of compounds deemed to have "negligible photochemical reactivity", and these are therefore exempt from the definition of VOC. These exempt compounds include methane, ethane, methylene chloride, methyl chloroform, many chlorofluorocarbons, and certain classes of perfluorocarbons. Additional compounds may be added to the exempt list in the future.

Though the regulatory definition of VOC is followed in ozone control programs, the exempt organic compounds are of concern when developing the complete emission inventory that is needed for broader applications. Therefore, this document strives to report the total organic emissions and component species, so that the user may choose those that are necessary for a particular application. In many cases, data are not available to identify and quantify either all the components (such as some oxygenated compounds that are not completely measured by many common test methods), the total organics, or other variations of the quantities desired. In such cases, the available information is annotated in an effort to provide the data to the user in a clear and unambiguous manner. It is not always possible to present a complete picture with the data that are available.

The term "total organic compounds" (TOC) is used in AP-42 to indicate all VOCs and all exempted organic compounds including methane, ethane, chlorofluorocarbons, toxics and HAPs, aldehydes, and semivolatile compounds. Component species are separately identified and quantified, if data are available, and these component species are included in TOCs. Often, a test method will produce a data set that excludes methane. In such cases, the term total nonmethane organic compound (TNMOC) may be used. Here, methane will be separately quantified if the data are available. Factors are nominally given in terms of actual weight of the emitted substance. However, in some cases where data do not allow calculation of the result in this form, factors may be given "as methane", "as propane", etc. Once the species distribution is determined, actual mass can be calculated based on molecular weight of each compound represented. In an AP-42 table giving organic emission factors, the ideal table headings would be:

TOC	Methane	Ethane	VOC	Other Species

Many organic compounds are also HAPs. Where such species can be quantified, an emission factor representing their individual mass will be presented. This quantity will also be included in the total VOC and/or TOC factors, as appropriate. To avoid double counting regarding permit fees, etc., this fact should be taken into consideration.

Sulfur Dioxide -

The primary product from combustion of sulfur is sulfur dioxide, SO_2. However, other oxidation states are usually formed. When reported in this document, these compounds are jointly referred to as SO_x, or oxides of sulfur. SO_2 means sulfur dioxide, and SO_x means the combination of all such emissions reported on the basis of the molecular weight of SO_2.

Oxides Of Nitrogen -

The primary combustion product of nitrogen is nitrogen dioxide, NO_2. However, several other nitrogen compounds are usually emitted at the same time (nitric oxide or NO, nitrous oxide or N_2O, etc.), and these may or may not be distinguishable in available test data. They are usually in a rapid state of flux, with NO_2 being, in the short term, the ultimate product emitted or formed shortly downstream of the stack. The convention followed in AP-42 is to report the distinctions wherever possible, but to report total NO_x on the basis of the molecular weight of NO_2.

Lead -

Lead is emitted and measured as particulate and often will be reported for a process both separately and as a component of the particulate matter emission factor. The lead may exist as pure metal or as compounds. The convention followed in AP-42 is that all emissions of lead are expressed as the weight of the elemental lead. Lead compounds will also be reported on the basis of the weight of those compounds if the information is available.

Toxic, Hazardous, And Other Noncriteria Pollutants -

Hazardous Air Pollutants are defined for EPA regulatory purposes in Title III of the *CAAA*. However, many states and other authorities designate additional toxic or hazardous compounds, organic or inorganic, that can exist in gaseous or particulate form. Also, as mentioned, compounds emitted as VOCs may be of interest for their participation in photochemical reactivity. Few EPA Reference Test Methods exist for these compounds, which may come from the myriad sources covered in this document. However, test methods are available to allow reasonably reliable quantification of many compounds, and adequate test results are available to yield estimates of sufficient quality to be included in this document. Where such compounds are quantified herein with emission factors, they represent the actual mass of that compound emitted. Totals for PM or VOC, as appropriate, are inclusive of the component species unless otherwise noted. There are a limited number of gaseous hazardous or toxic compounds that may not be VOCs, and whenever they occur they will be identified separately.

The Emission Factor And Inventory Group produces a separate series of reports that focus on a number of the more significant HAPs and related sources. Titles of these documents generally follow the format of *Locating And Estimating Emissions From Sources Of. . . (Substance).*

Examples Of Emission Factor Application -

Calculating carbon monoxide (CO) emissions from distillate oil combustion serves as an example of the simplest use of emission factors. Consider an industrial boiler that burns 90,000 liters of distillate oil per day. In Section 1.3 of AP-42, "Fuel Oil Combustion", the CO emission factor for industrial boilers burning distillate oil is 0.6 kilograms (kg) CO per 10^3 liters of oil burned.

Then CO emissions

= CO emission factor x distillate oil burned/day
= 0.6 x 90
= 54 kg/day

In a more complex case, suppose a sulfuric acid (H_2SO_4) plant produces 200 Mg of 100 percent H_2SO_4 per day by converting sulfur dioxide (SO_2) into sulfur trioxide (SO_3) at 97.5 percent efficiency. In Section 8.10, "Sulfuric Acid", the SO_2 emission factors are listed according to SO_2-to-SO_3 conversion efficiencies in whole numbers. The reader is directed by footnote to an interpolation formula that may be used to obtain the emission factor for 97.5 percent SO_2-to-SO_3 conversion.

The emission factor for kg SO_2/Mg 100% H_2SO_4

= 682 - [(6.82)(% SO_2-to-SO_3 conversion)]
= 682 - [6.82)(97.5)]
= 682 - 665
= 17 kg

In the production of 200 Mg of 100 percent H_2SO_4 per day, SO_2 emissions are calculated thus:

SO_2 emissions
= 17 kg SO_2 emissions/Mg 100 percent H_2SO_4 x 200 Mg 100 percent H_2SO_4/day
= 3400 kg/day

Emission Factor Ratings

Each AP-42 emission factor is given a rating from A through E, with A being the best. A factor's rating is a general indication of the reliability, or robustness, of that factor. This rating is assigned based on the estimated reliability of the tests used to develop the factor and on both the amount and the representative characteristics of those data. In general, factors based on many observations, or on more widely accepted test procedures, are assigned higher rankings. Conversely, a factor based on a single observation of questionable quality, or one extrapolated from another factor for a similar process, would probably be rated much lower. Because ratings are subjective and only indirectly consider the inherent scatter among the data used to calculate factors, the ratings should be seen only as approximations. AP-42 factor ratings do not imply statistical error bounds or confidence intervals about each emission factor. At most, a rating should be considered an indicator of the accuracy and precision of a given factor being used to estimate emissions from a large number of sources. This indicator is largely a reflection of the professional judgment of AP-42 authors and reviewers concerning the reliability of any estimates derived with these factors.

Because emission factors can be based on source tests, modeling, mass balance, or other information, factor ratings can vary greatly. Some factors have been through more rigorous quality assurance than others.

Two steps are involved in factor rating determination. The first step is an appraisal of data quality, the reliability of the basic emission data that will be used to develop the factor. The second step is an appraisal of the ability of the factor to stand as a national annual average emission factor for that source activity.

Test data quality is rated A through D, and ratings are thus assigned:

A = Tests are performed by a sound methodology and are reported in enough detail for adequate validation.
B = Tests are performed by a generally sound methodology, but lacking enough detail for adequate validation.
C = Tests are based on an unproven or new methodology, or are lacking a significant amount of background information.
D = Tests are based on a generally unacceptable method, but the method may provide an order-of-magnitude value for the source.

The quality rating of AP-42 data helps identify good data, even when it is not possible to extract a factor representative of a typical source in the category from those data. For example, the data from a given test may be good enough for a data quality rating of "A", but the test may be for a unique feed material, or the production specifications may be either more or less stringent than at the typical facility.

The AP-42 emission factor rating is an overall assessment of how good a factor is, based on both the quality of the test(s) or information that is the source of the factor and on how well the factor represents the emission source. Higher ratings are for factors based on many unbiased observations, or on widely accepted test procedures. For example, ten or more source tests on different randomly selected plants would likely be assigned an "A" rating if all tests are conducted using a single valid reference measurement method. Likewise, a single observation based on questionable methods of testing would be assigned an "E", and a factor extrapolated from higher-rated factors for similar processes would be assigned a "D" or an "E".

AP-42 emission factor quality ratings are thus assigned:

A — Excellent. Factor is developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.

B — Above average. Factor is developed from A- or B-rated test data from a "reasonable number" of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with an A rating, the source category population is sufficiently specific to minimize variability.

C — Average. Factor is developed from A-, B-, and/or C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.

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D — Below average. Factor is developed from A-, B- and/or C-rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.

E — Poor. Factor is developed from C- and D-rated test data, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.

Public Review Of Emission Factors

Since AP-42 emission factors may have effects on most aspects of air pollution control and air quality management including operating permit fees, compliance assessments, and SIP attainment emission inventories, these factors are always made available for public review and comment before publication. The Emission Factor And Inventory Group panel of public and peer reviewers includes representatives of affected industries, state and local air pollution agencies, and environmental groups. More information on AP-42 review procedures is available in the document, *Public Participation Procedures For EPA's Emission Estimation Guidance Materials*, EPA-454/R-94-022, July 1994. This publication is available on EFIG's *CHIEF* (Clearinghouse For Inventories And Emission Factors) electronic bulletin board (BB) and its *Fax CHIEF*, an automated facsimile machine. It is also available in conventional paper copy from the National Technical Information Service (NTIS). The Agency encourages all interested parties to take every opportunity to review factors and to provide information for factor quality improvement. Toward this objective, EFIG invites comments and questions about AP-42, and users are invited to submit any data or other information in accordance with this procedures document.

Other Ways To Obtain AP-42 Information And Updates

All or part of AP-42 can be downloaded either from the *CHIEF* BB or *Fax CHIEF*, and it is available on the *Air CHIEF* CD-ROM (Compact Disc - Read Only Memory). AP-42 is available in conventional paper copy from the Government Printing Office and NTIS, as well as through the *Fax CHIEF*.

The emission factors contained in AP-42 are available in the *Factor Information Retrieval System* (*FIRE*). Also, software has been developed for emission models such as *TANKS*, *WATER7*, the *Surface Impoundment Modeling System* (*SIMS*), and fugitive dust models. This software and the *FIRE* data base are available through the *CHIEF* BB. *FIRE* is also on the *Air CHIEF* compact disc. The *Fax CHIEF* and the *CHIEF* BB will always contain the latest factor information, as they are updated frequently, whereas *Air CHIEF*, the *FIRE* program, and printed AP-42 portions are routinely updated only once per year.

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VOLUME II: CHAPTER 2

PREFERRED AND ALTERNATIVE METHODS FOR ESTIMATING AIR EMISSIONS FROM BOILERS

January 2001

Prepared by:
Eastern Research Group, Inc.

Prepared for:
Point Sources Committee
Emission Inventory Improvement Program

DISCLAIMER

As the Environmental Protection Agency has indicated in Emission Inventory Improvement Program (EIIP) documents, the choice of methods to be used to estimate emissions depends on how the estimates will be used and the degree of accuracy required. Methods using site-specific data are preferred over other methods. These documents are non-binding guidance and not rules. EPA, the States, and others retain the discretion to employ or to require other approaches that meet the requirements of the applicable statutory or regulatory requirements in individual circumstances.

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Calculations with no ash adjustment

	(1) #SO2 per MMBtu Bitum.	(2) #SO2 per MMBtu PRB x 0.9	(3) #SO2 per MMBtu	(4) MMBtu x 1000	(5) Excess SO2 Tons	(6) SO2 Allowance Price $/Ton	(7) Excess SO2 Cost ($)	
Year								
2000	1.12	0.6	0.52	36,317	9,442	141	1,331,381	
2001	1.11	0.6	0.51	35,796	9,128	186	1,697,804	
2002	1.12	0.6	0.52	37,753	9,816	152	1,491,999	
2003	1.03	0.6	0.43	32,781	7,048	176	1,240,433	
2004	1.04	0.6	0.44	37,980	8,356	442	3,693,175	
2005	1.02	0.6	0.42	34,347	7,213	906	6,534,860	$15,989,653

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Mathematical Corrections to Sansom Exhibit RS-26 with J. Heller MMBtu adjustments

Year	(1) #SO2 per MMBtu Bitum.	(1A) #SO2 per MMBtu Bitum. X .95	(2A) #SO2 per MMBtu PRB	(2B) #SO2 per MMBtu PRB x 0.875	(3) #SO2 per MMBtu	(4) MMBtu x 1000	(5) Excess SO2 Tons	(6) SO2 Allowance Price $/Ton	(7) Excess SO2 Cost ($)	
2000	1.12	1.064	0.6	0.525	0.54	30,052	8,099	141	1,141,973	
2001	1.11	1.055	0.6	0.525	0.53	30,427	8,055	186	1,498,312	
2002	1.12	1.064	0.6	0.525	0.54	37,753	10,174	152	1,546,514	
2003	1.03	0.979	0.6	0.525	0.45	32,781	7,433	176	1,308,224	
2004	1.04	0.988	0.6	0.525	0.46	37,980	8,792	442	3,886,228	
2005	1.02	0.969	0.6	0.525	0.44	31,771	7,053	906	6,390,160	$15,771,411

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Calculations with no ash adjustment and with J. Heller MMBTU adjustments

Year	(1) #SO2 per MMBtu Bitum.	(2) #SO2 per MMBtu PRB x 0.9	(3) #SO2 per MMBtu	(4) MMBtu x 1000	(5) Excess SO2 Tons	(6) SO2 Allowance Price $/Ton	(7) Excess SO2 Cost ($)	
2000	1.12	0.6	0.52	30,052	7,814	141	1,101,718	
2001	1.11	0.6	0.51	30,427	7,759	186	1,443,134	
2002	1.12	0.6	0.52	37,753	9,816	152	1,491,999	
2003	1.03	0.6	0.43	32,781	7,048	176	1,240,433	
2004	1.04	0.6	0.44	37,980	8,356	442	3,693,175	
2005	1.02	0.6	0.42	31,771	6,672	906	6,044,746	$15,015,204