

TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 95OPEP007
to be issued to:

Colorado Springs Utilities
George Birdsall Power Plant
El Paso County
Source ID 0410003

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April 9, 1997

I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the original application submittal of December 29, 1994; supplemental technical submittals of March 8, and August 15, 1995; January 17, June 7, August 1, August 13, and September 4, 1996; a site visit on July 18, 1996; previous inspection reports, as well as numerous telephone conversations with the applicant.

II. SOURCE DESCRIPTION:

This facility is located in Colorado Springs, Colorado. Colorado Springs is classified as nonattainment for carbon monoxide. There are no Federal Class I designated areas within 100 kilometers of the plant, and no affected states within 50 miles. Florissant Fossil Beds is a Federal land area within 100 kilometers of the facility. Florissant Fossil Beds has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

The facility is one of the Colorado Springs electrical power generating plants. The facility's boilers are currently operated in response to peak electrical demands which are met by the Colorado Springs Utilities (CSU) electrical generation facilities. Thus, in recent years, the facility's boilers have not operated continuously. However, in the future CSU may choose to operate the facility's boilers on a more frequent basis or even continuously. As a peaking unit, the facility is subject to frequent startups and generally operates for a small amount of time in any year. The limited operating time results in low actual annual emissions. The primary features of the facility are three steam boilers, with their associated turbine-generator and cooling tower. The boilers can burn either pipeline natural gas or fuel oil. There is an auxiliary heating boiler for heating the fuel oil. An extensive list of insignificant sources of emissions was also submitted for the facility.

At the time the Title V application was submitted, the facility was configured to allow the steam boilers for the turbines to burn natural gas, No. 2 distillate, No. 6 Residual Oil and an alternate scenario was requested to allow burning of Specification Used Oil. The No. 6 Residual Oil must be kept heated to near 150°F in order to flow through the piping. The oil heating equipment was starting to require frequent and extensive repairs, and creating operating problems. In addition, the valving and piping necessary to operate from four different storage tanks was starting to become complex. After review and analysis the permittee made the decision to convert to the use of only Specification Used Oil and No. 2 distillate. Excess equipment would be removed under the conversion contract. This change greatly simplified the operation and removed a number of environmental requirements related to on-site storage of large amounts of fuel oil. The contract for the conversion is expected to be completed in August or September of 1996.

The following tabulation of emissions taken from the Title V application shows the contrast between the estimated total actual annual emissions and the total potential to emit for the plant. The impact of the fuel use change on the potential to emit is also shown in the presentation of the “Before Construction” and “After Construction” potential to emit values.

POLLUTANT	POTENTIAL TO EMIT, TPY					ACTUAL EMISSIONS, TPY
	Before Construction			After Construction		
	NG	#2 FO	#6 RO	NG	Spec Oil	
PM	131.08	167.11	470.20	131.08	994.33	2.840
PM ₁₀	131.08	143.90	369.07	131.08	851.11	2.840
SO _x	1.99	4611.83	4774.44	1.99	1619.49	negligible
NO _x	1792.51	463.96	1455.36	1792.51	418.64	3.500
VOC	4.70	7.85	16.51	4.70	22.04	0.798
CO	131.52	115.99	108.60	131.52	110.16	0.280
PB	negligible	0.03	0.34	negligible	--	Less than reporting level
H ₂ SO ₄ Mist	negligible	79.89	213.21	negligible	--	Less than reporting level
HAPS						0.033*

NG = natural gas #2 FO = #2 Distillate #6 RO = #6 Residual Oil

* Does not include combustion HAPS

The low actual annual emissions were considered in establishing the reporting intervals. The existing fuel sampling plan required quarterly submittals of reports. The decision was made

that the low actual emissions did not justify the resource expenditures required for quarterly reporting. The quarterly reporting requirement was changed to a semi-annual requirement, the minimum frequency acceptable for Title V. The reporting interval may have to be adjusted in the future if the annual emissions show a sustained increase.

The Title V application reports this facility is not subject to the requirements of Section 112(r)(7), the Accidental Release Plan Program of the Clean Air Act. File information and the Title V application indicates none of the boilers are subject to the Title IV, Acid Rain Program.

The compliance status of each source is based on the information provided in the application and a review of the office files available. No non-compliance issues were discovered in the file review. The Division accepts the facility was in compliance at the time the Title V application was submitted. Since no compliance plan or schedule was included for start-up, shut-down or malfunction opacity exceedances, it is accepted that the facility has adequate and appropriate control programs in place.

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

Units B001 & B002 - 216 MMBTU/Hr Springfield 516A Boilers

1. Applicable Requirements - B001 went into service in 1953. B002 went into service in 1954. Both units have regulatory grandfather status regarding the construction permits program. The units are subject to the requirements of State Regulation #1. Regulation #1 uses the following equation to establish a particulate emissions limit:

$$PE = 0.5(FI)^{-0.26}$$

PE = Particulate Emissions in pounds per million BTU heat input
FI = Fuel Input in Million BTU (MMBTU) per hour (Hr)

The standard set by this equation for each of these boilers is 0.124 pounds of particulate per MMBTU. A calculation using the AP-42 emission factor (3 pounds per million standard cubic feet) and the natural gas heat content (986 Btu per standard cubic foot) results in a value of 0.0030 pounds per million Btu, which demonstrates the standard will not be exceeded when burning pipeline quality natural gas. A similar calculation can be made for the distillate fuel oil. Using the AP-42 emission factor (2 pounds per thousand gallons) and the distillate heat content (140,000 Btu per gallon) results in a value of 0.0143 pound per million Btu which again demonstrates the standard will not be exceeded when burning commercially marketed distillate.

The permittee will have to be mindful of the quality of the Specification Used Oil received. The average physical properties information provided by a prospective vendor reported an ash content of 0.6 %, and a typical heat value of 141,600 BTU per gallon. Using these values for a compliance determination calculation found that the Regulation 1 limitation would be exceeded. The standard will be exceeded if the ash content exceeds 0.265% at the current heating value. This consideration required the fuel analysis program to include the fuel oil ash content and justifies the need for a close evaluation of the quality of the fuel oil being burned.

The units are subject to the standard set by Regulation No. 1, §VI.A.3.b.(I) when burning fuel oil. The standard is set at 1.5 pounds of sulfur dioxide emissions per million Btu of heat input. A calculation for the distillate using the fuel oil heat value (140,000 Btu/gallon) and sulfur content (1.4%) reported in the Title V application, combined with the AP-42 emission factor for SO₂ (142S), identifies the facility to be in compliance with the SO₂ emission standard. The sulfur content of the distillate would have to exceed 1.48% by weight (at the current heat content level) to exceed the standard. A similar calculation for the Specification Used Oil finds the facility in compliance. The Specification Used Oil sulfur content would have to exceed 1.43% before the standard was exceeded. Because the standard is related to the fuel heat and sulfur content and not the fuel consumption rate, a fuel quality monitoring plan provides an efficient method for monitoring compliance with both the particulate and sulfur dioxide standard.

2. Emission Factors - Emissions from the boilers result from burning natural gas and No. 2 distillate and Specification Used Oil (see alternate scenarios). The primary criteria pollutants of concern are nitrogen oxides (NO_x) and sulfur oxides (SO_x). Standard factors from the AP-42 manual were selected for determining the actual emissions. The particulate and sulfur dioxide emissions are related to the sulfur or ash content of the fuel when burning No. 2 distillate or Specification Used Oil. Since the sulfur and ash content of the oil can span a range of values, a fuel analysis must be made to determine the values needed for emissions estimations.

The facility has the capability to burn fuel oil and natural gas simultaneously. There are no readily available published figures for this scenario. However, based on engineering judgement, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the fuel oil fraction and natural gas fraction.

A No. 6 Residual Oil sampling and analysis program had previously been established and implemented for B003 in lieu of providing continuous emissions monitoring. More details on the fuel oil sampling program are provided later in the discussion of Unit B003. A fuel quality monitoring procedure was proposed for B001, B002 and B004, the auxiliary boiler. The monitoring procedure would use fuel oil quality values from vendor delivery receipts

in a computer spreadsheet to determine the weighted average values of the fuel oil properties in the storage tanks. A random sampling program would be conducted to validate the vendor delivery receipts. When Unit 3 (B003) is operating, actual test results can be compared to the calculated values for additional validation of the spreadsheet values. The monitoring results will provide the values needed for compliance determinations or emissions estimates. If the calculation monitoring procedure is found to be inadequate or unsatisfactory, the existing fuel sampling plan for Unit 3 (B003) will be modified to provide fuel samples from one of the operating boilers. Tank sampling was considered but discarded. Tank sampling would require multiple samples from various levels in this large tank. In addition, the samples would have to be collected from the top of the tank during all kinds of weather, raising issues of personnel safety.

3. Monitoring Plan - The grandfathered status of the boilers reduces the amount of monitoring required. Since the units are used on an intermittent basis to meet peak demands, they will be subject to frequent startups. Startups for large boilers may take an extended time and may result in significant opacity. Operating staff experience may have an affect on the both the startup time required and opacity problems.

The general operating procedure for this plant is to use natural gas for boiler startup. The facility currently has contracts for an interruptible natural gas supply and a guaranteed delivery natural gas supply. The boilers operate on the interruptible natural gas supply. When natural gas delivery must be interrupted by the vendor, the boiler switches to burning fuel oil. The switch-over is accomplished burner-by-burner until all the burners are using fuel oil. The process is reversed to returned to natural gas service.

If a boiler must be placed in service from a cold standby, the unit is heated by burning natural gas under the guaranteed natural gas contract if the interruptible gas service contract can not be used. It takes approximately 12 hours to bring the boiler up to the steaming level necessary to operate the turbine. Once the turbine is in operation, the natural gas supply is replaced by fuel oil if necessary.

If a boiler must be taken off-line while burning fuel oil, the startup procedure is reversed. The fuel oil is purged from each of the burners using natural gas, until all the burners are burning natural gas. At this point, the heat can be reduced rapidly and the unit shut down.

The Division accepts the position that, based on AP-42 emission factors and engineering judgement, the combustion of natural gas in a properly operated facility does not produce enough particulate matter to require opacity observations. Fuel oil use, however, has a significant potential for opacity problems, particularly for cold startups. The startup and shutdown procedure practiced at this facility minimizes the potential for opacity problems. The opacity monitoring prescribed by the permit is intended to validate that the fuel switch-over does not create a problem.

The need for monitoring of the sulfur and ash content of the fuel oil was described above in relationship to the emissions factor application. The heat content of the fuels is needed for determining compliance with the Regulation 1 limit. The sulfur dioxide emissions from burning natural gas are only a fraction of the emission standard. The natural gas combustion sulfur dioxide monitoring interval was set at an annual basis because it is unlikely the standard would ever be exceeded.

The actual annual emissions from the facility have been much less than 100 TPY for the criteria pollutants. On this basis, Revised APENs are only required when the level of any criteria pollutant increases by 5 TPY or more.

4. Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

Unit B003 - 299 MMBTU/Hr Springfield Boiler

1. Applicable Requirements - B003 went into service in 1957. The boiler has regulatory grandfather status regarding construction permits, and does not require a construction permit. The unit is subject to the requirements of State Regulation #1. Regulation #1 sets a limit for B003 with the same equation as used for B001 & B002. The limit is 0.114 pounds of particulate per MMBTU. The logic used to set permit limits for this boiler is explained above for the other boilers.

Regulation 1 §IV.B.1.b requires this boiler to be equipped with a COM unless the source can demonstrate compliance with the particulate matter and opacity regulation without utilization of particulate matter control equipment. As noted in the above information for B001 and B002, calculation indicates there is the potential to exceed the particulate matter standard when burning Specification Used Oil unless the ash content is limited. Regulation 1 §IV.B 2 requires this boiler to be equipped with a sulfur dioxide continuous emissions monitor, or to implement a State approved fuel sampling program for estimating sulfur dioxide emissions. A fuel sampling program was approved by the Division and is discussed below in Section 3.

2. Emission Factors - See discussion for B001 & B002.

3. Monitoring Plan - The size of B003 makes the unit subject to the requirements of Regulation 1 §IV. The exemptions of Regulation 1 §IV.B allow the unit to avoid the requirement for providing a continuous opacity monitor. Regulation 1 §IV.B.2 requires the this unit to either provide and operate a continuous emission monitoring system for sulfur

dioxide or develop and implement a plan for determining the sulfur content of the fuel. A fuel sampling plan was developed, approved by the Division and implemented. The existing plan requires the analysis of the heat content and sulfur content of the No. 2 distillate and the No. 6 Residual Oil. The plan needs to be modified to reflect the replacement of the use of No. 6 residual oil with Specification Used Oil, and the ability to burn a mixture of fuel oils. The sulfur content and the heat content values are required for the sulfur dioxide emissions determination identified in the fuel sampling procedure and included in the operating permit. See also the discussion for B001 & B002.

4. Compliance Status - The Division accepts the unit was in compliance at the time the Title V application was submitted.

Units B001, B002 & B003 - Alternate Operating Scenarios

The Title V application includes two alternate operating scenarios. One scenario is for the disposal of spent boiler tube cleaning materials in a boiler. The other scenario is for the use of Specification Used Oil as a fuel.

Spent Boiler Tube Cleaning Materials - Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. Operating experience for this utility has identified the need to clean the tubes approximately once every 10 years. The cleaning is accomplished by circulating cleaning solutions, generally strong acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. This has been an on-going practice for other boilers operated by the utility and has not been cited by the Division as a compliance issue. The quantity of the materials requiring disposal is reported to be limited. A laboratory chemist establishes a material feed rate that will accomplish the complete combustion of the materials. The combination of the limited quantities, the injection rate and the combustion temperatures of the boiler are expected to result in proper disposal of the materials. The Division, however, needs to be aware of when and how much material is being processed. An opacity observation is required to provide a direct indicator of proper operation during the material disposal. The operating permit limitations may have to be adjusted if the type of materials is different than expected or the quantity of materials is greater than expected.

Specification Used Oil - Specification Used Oil is another name for waste oil. 40 CFR Part 279 §279.11 sets upper limits for certain constituents/compounds in the oil to avoid classification as a hazardous material. The applicant will also establish purchase

specifications to avoid purchasing a hazardous material. AP-42, Section 1.11 reports waste oil composition is somewhere between that of general distillate and No. 6 Residual Oil; except the waste oil ash content is greater than the ash content for either No. 2 or 6. The increased ash content may be expected to result in increased particulate emissions which may lead to increased opacity levels. The potential opacity problems needed to be recognized in the operating permit. In addition, the waste oil may contain more trace elements and HAPs than the other fuel oils. This impact will need to be evaluated once the EPA information on the HAPs emissions from power plant stacks is released. The AP-42 waste oil emission factors for small boilers are included in the permit for use until actual fuel analysis values are available. The heating value was selected to be the same as the No. 6 Residual Oil.

The composition of the Specification Used Oil may vary from shipment to shipment. The mixing of an off-loaded shipment with the existing contents of the storage tank may result in a new fuel oil composition. Further, operating experience may find improved performance from mixing some distillate oil with the waste oil for improved combustion. The Used Oil specification limits could have been incorporated in the permit. Inclusion of the specification limits would allow estimation of the emissions on a worst case basis, but it would also limit the purchasing flexibility of the facility. In the event market prices were more favorable for used oil slightly outside the permit specification limits, the facility would have to change the permit values before the oil could be used. The fuel sampling program was expanded to allow the facility to have the flexibility to use oils available, while providing the information needed to reasonably estimate the actual emissions when using any of the oils for fuel.

The existing combustion units have regulatory grandfather status and are already equipped to burn oil. Since no modification of the units is needed to use the Specification Used Oil, a construction permit is not required. Submittal of an APEN is required whenever the estimated actual annual emissions from using the oil exceed the APEN reporting threshold(s).

Unit B004 - 10.9 MMBTU/Hr Superior Heating Boiler

See the discussion for B001, B002 or B003.

Units P001 & P002 - 16,000 GPM Cooling Towers
Unit P003 - 22,000 GPM Cooling Tower

1. Applicable Requirements - The cooling towers were placed in service with their respective boilers. The towers have regulatory grandfather status with regards to construction permits; therefore, a construction permit is not required. See the Permit Shield section for comments in regard to the possibility of the application of Regulation 1 particulate limits.

2. Emission Factors - The Division first became aware of the need to consider power plant cooling tower emissions in 1992. At that time, AP-42 provided limited information regarding cooling tower potential emissions of particulate matter, VOCs and possible HAPs. The cooling tower particulate emissions are produced by evaporation of the water droplets released into the air. The evaporation leaves a residue formed from the mineral content of the water. The estimated particulate emissions are lower than what would be obtained from using AP-42 factors, but are accepted as being a more realistic reflection of the local conditions. Much of the available information for the development of the AP-42 emission factors is from east coast area facilities where the water used is more highly mineralized than Colorado waters. In addition, because the initial mineral concentration of the cooling tower makeup water is low, the trigger point for reducing the circulating cooling tower water mineral concentration can be set at a low value. The end result is less mineral residue in the evaporate water droplet.

The VOC and HAP of concern from cooling towers is chloroform. The chlorination of the recirculated tower water results in chloroform formation and release from the circulating water. The Title V application presented a logical analysis for the estimation of the chloroform emissions.

3. Monitoring Plan - The cooling towers fit into the permit program in a different manner from most sources. The potential emissions from cooling towers became a concern in late 1992. Since that time the amount of annual operating time of this facility has been at levels which result in the estimated annual actual emissions from the towers being less than the APEN reporting threshold. However, the database indicates historic operating levels have been high enough to reach the APEN reporting threshold. On this basis, the amount of time each tower is used will need to be tracked to signal when APEN reporting is required.

4. Compliance Status - The Division accepts the position that the limited level of operation of the cooling towers since 1992 has not required APEN reporting. The towers are in compliance.

Permit Shield

Regulation 7 §VI.B.2.b requires above ground storage tanks larger than 40,000 gallons storing No. 6 fuel oil to be coated with a material having a solar reflectivity of greater than or equal to 0.7. This requirement appears unusual since the No. 6 Residual Oil is less volatile than the petroleum liquids which are listed as exempt from this requirement. The PTE calculations in the application demonstrate that the emissions for the non-exempt No. 6 RO are about 100 times less than the emissions for No. 2 distillate, which is exempt from the coating requirement. The reflective level of the tank coating will not have a significant impact on the No. 6 RO emissions. The use of No. 6 RO has been discontinued. The Specification Used Oil is characterized or blended to approximately the same consistency as No. 4 fuel oil. Since the No. 4 fuel oil is exempt from the Regulation 7 requirement, the exemption is extended to the Specification Used Oil by the Permit Shield.

Regulation 1 §III.C.1.b establishes a particulate emission standard for manufacturing processes. The Standard Industrial Classification (SIC) codes commonly used to group sources uses different codes for electrical power generation and manufacturing processes. In addition, EPA FIRE Version 5.0 lists cooling towers in the section with manufacturing processes and not with electrical power generation. Finally, historically, the Division has not evaluated power plant cooling towers particulate emissions under this part of Regulation 1. On the basis of the preceding, the permit shield is extended to the cooling tower particulate emissions.

The intent of the permit shield is to provide limited protection to the facility in the event of an error in the evaluation of whether a regulation, or portion of a regulation applies. The facility identifies the issue and presents its position. The Division reviews the position. If the Division and the facility mutually agree on the position, the issue is recorded in the permit. If, at a later date, it is determined that an error was made in the mutual decision, the facility is protected from enforcement action until the permit can be reopened and the correct requirements and a compliance schedule inserted.

In this application, the applicable sections of the Federal and State regulations are identified for the sources. A blanket request was made for the shield protection from unidentified non-applicable sections of the regulations. Since no specific issues, other than the Regulation 7 shield request noted above, have been identified, only Regulation 7 §VI.B.2.b is included as a specific non-applicable requirement in the permit.

Hazardous Air Pollutants

At the time the Title V application was submitted, the reporting of estimated actual hazardous air pollutants (HAPs) emissions from combustion at utility steam boilers used for electrical power generation had been deferred until the findings of an EPA scientific study were released, or September 30, 1996, whichever came earliest. In an effort to provide an estimate of the potential-to-emit for the combustion HAPs, the Title V application used emission factors available from AP-42 for calculation of the best available approximation of the emissions. The permittee has reported the estimated HAPs to the Division in accordance with the September 30, 1996, deadline. The review of the information submitted has not yet been completed; therefore, the information is not yet available from the Division database.

The potential-to-emit estimations of the HAPs emissions from the auxiliary boiler approach or exceed the APEN reporting threshold. The actual emissions are currently well below the reporting thresholds.

Halon is used for fire suppression in the control center building. Halon is a CFC, and a non-criteria reportable pollutant with an APEN reporting threshold of 1000 - 5000 pounds. The limit is dependent on the distance to the property line. The Halon will only have to be reported when a protective release exceeds the appropriate threshold.

Chlorine is used in the cooling tower water to control biological growths. Chlorine in the water forms chloroform as a by-product. The chloroform is a volatile compound, a hazardous air pollutant and was calculated and reported as required.

Miscellaneous

From time to time published emission factors are changed based on new or improved data. A logical concern is what happens if the use of the new emission factor in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors or emission factor equations included in the permit are considered to be fixed until changed by the permit. Obviously, factors dependent on the fuel sulfur content or heat content can not be fixed and will vary with the test results. The formula for determining the emission factors is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, and to notify the Division in writing of impacts on the permit requirements when there is a change in factors. Upon notification, the Division will work with the permittee to address the situation.

ADDENDUM

During the time the permit was available for public comment, the Division discovered that the open burning regulation had been incorporated into the State Implementation Plan (SIP), making the open burning regulation Federally enforceable. The error has been corrected by removing this condition from the State-only enforceable conditions listed in Condition 1.4 of Section I of the permit.

Also during the public comment period, the Division determined that the Operating Permits would be improved if the potential-to-emit (PTE) values were shown in the permit for grandfathered sources. The PTE is set by the design capacity of a source, and while not a regulatory limit, is an operating limit. The inclusion of these values provides the permit user with a perspective of the maximum emissions for a source. During the process of placing the values in the permit it was discovered that the PTE values shown in the Technical Summary table were incorrect. The values did not reflect the potential for the auxiliary boiler to burn specification used oil. The values in the table have been corrected as necessary.