September 4, 2020

Owen Orndorff
President, Billings Generation Inc.
(general partner of) Yellowstone Energy Limited Partnership
1087 W. River Street, Suite 200
Boise, ID 83702

Dear Mr. Orndorff:

Montana Air Quality Permit #2650-09 is deemed final as of September 4, 2020, by the Department of Environmental Quality (Department). This permit is for an administrative amendment. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Julie A. Merkel
Permitting Services Section Supervisor
Air Quality Bureau
(406) 444-3626

Julie Ackerlund
Air Quality Engineer
Air Quality Bureau
(406) 444-4267

JM:JA
Enclosure

Montana Department of Environmental Quality
Air, Energy & Mining Division

Montana Air Quality Permit #2650-09

Yellowstone Energy Limited Partnership
1087 W. River Street, Suite 200
Boise, ID 83702

September 4, 2020

MONTANA AIR QUALITY PERMIT

Issued To:	Yellowstone Energy Limited Partnership Yellowstone Power Plant 1087 W. River Street, Suite 200 Boise, ID 83702	MAQP: #2650-09 Administrative Amendment (AA) Request Received: 01/23/2020 Department Decision on AA: 08/19/2020 Permit Final: 09/4/2020 AFS: #025-0013

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Yellowstone Energy Limited Partnership (YELP), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

Section I: Permitted Facilities

A. Plant Location

YELP operates a petroleum coke-fired electrical/steam co-generation facility southeast of the Exxon Refinery in Billings. The facility generates electrical power, which is sold to the Northwestern Energy, and steam, which is supplied to the Exxon facility. YELP is located in the NE¼ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana. A complete listing of permitted equipment is contained in the permit analysis.

B. Current Permit Action

On January 23, 2020, the Montana Department of Environmental Quality (Department) received an Administrative Amendment (AA) request from YELP to remove the ambient air quality monitoring requirements from the permit. Additional correspondence was received on July 29, 2020. The current permit action updates the permit to reflect the removal of the ambient air quality monitoring requirements.

Section II: Conditions and Limitations

A. YELP shall verify the sulfur dioxide emission rate, utilizing continuous emission monitors, on an hourly basis on both the YELP stack and from the Exxon coker process gas received by the YELP facility. The results shall be reported to the Department, along with other emissions data, within 30 days of the end of each reporting period. The report shall contain all necessary data from the coker process gas stream, fuel petroleum coke sulfur content, and the YELP main stack continuous emission monitoring system such that the sulfur dioxide emission reduction is quantifiable on an hourly basis (ARM 17.8.749).

B. The sulfur dioxide emission reduction from the Exxon coker process gas shall be at least 238 tons per calendar year. The short-term hourly offset shall be guaranteed according to the provisions listed in Section II.M (ARM 17.8.749).

C. The facility shall burn, in conjunction with petroleum coke fuel, all the Exxon process gas in the YELP boilers. YELP shall report to the Department, within 24 hours, any time the Exxon coker process gas is diverted away from the fluidized bed boiler facility (YELP). Said report shall include the period of diversion, estimate of process gas diverted, and circumstances explaining the diversion of this stream. Said report shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the diversion (ARM 17.8.749).

D. All storage silos, surge bins, hoppers, limestone crushing, and conveyor systems shall utilize baghouses (bag filters) for particulate emission control (ARM 17.8.752).

E. The limestone load-in hopper (used to load in limestone) and ash load-out operations shall be enclosed and particulate emissions controlled by baghouses (bag filters) (ARM 17.8.749).

F. The Coke Unloading/Crushing/Processing facility shall be completely enclosed and utilize a baghouse to control emissions from the crusher, screen, and associated conveyors (ARM 17.8.752).

G. The Coke Barn and the conveyor system linking the Coke Unloading/Crushing/Processing facility to the Coke Barn shall be enclosed (ARM 17.8.752).

H. The pneumatic coke transfer system, storage silo, and dispensing system shall be enclosed and particulate emissions controlled by baghouses (bag filters) (ARM 17.8.749).

I. The Coke Load-out Silo shall be enclosed and particulate emissions controlled by baghouses (ARM 1 7.8.749).

J. The processing of off-site petroleum coke (crushing, handling, and storage) shall take place in the Coke Unloading, Crushing, Processing facility, the Coke Barn, and at the existing Exxon Refinery coke storage area only. Off-site petroleum coke means coke that is not produced at the Billings Exxon/Mobil refinery. Specific limits applicable to the processing and storage of off-site coke at the YELP facility are as follows (ARM 17.8.749):

    1. The total amount of off-site petroleum coke delivered to YELP shall not exceed 240,900 tons during any rolling 12-month time period, unless, off-site coke is being transported to and stored at the Exxon Refinery coke storage area as specified in Section II.J.2.

    2. If off-site petroleum coke is transported to and stored at the Exxon Refinery coke storage area then the following conditions apply (ARM 17.8.749):

        a. The total amount of off-site petroleum coke transported, dumped, and stored at the Exxon Refinery coke storage area shall not exceed 35,000 tons during any rolling 12-month time period.

b. The total amount of off-site coke delivered to the Coke Barn shall not exceed 202,000 tons during any rolling 12-month time period. This limit applies while transporting, dumping, and storing off-site petroleum coke at the Exxon Refinery coke storage area and during the ensuing 12-months after completion of the coke barn or the last dump of off-site coke at the Exxon refinery coke storage area whichever is later.

K. All systems within the facility shall be completely enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in Section II.P (ARM 17.8.749).

L. YELP shall comply with, at a minimum, all applicable Standards of Performance for New Stationary Sources (NSPS) provisions, as appropriate, of 40 CFR 60, Subpart Da, 60.40a through 60.49a, Standards of Performance for Electric Utility Steam Generating Units (ARM 17.8.340 and 40 CFR 60, Subpart Da).

M. The construction and operation of the YELP facility required external offsets from the adjacent Exxon refinery. The offsets are provided by the combustion and treatment of the Exxon coker process gas stream, by both an hourly limit on sulfur-in-fuel burned at the refinery on a refinery-wide basis of 0.96 lbs. of sulfur-in-fuel per million British thermal units (lb/MMBtu) fired and a daily limit on the number of barrels of fuel oil that may be burned at the refinery by all combustion units of 720 barrels per calendar day. The following operating conditions are applicable to the YELP facility:

1. At any time YELP is notified by Exxon that Exxon has exceeded either the hourly sulfur-in-fuel limitation or the daily limit on the number of barrels of fuel oil fired, YELP shall operate its facility in such manner as to ensure the ratio of sulfur dioxide in the Exxon coker process gas stream to the sulfur dioxide emitted from the YELP main stack shall be equal to or greater than 1:1. During the times the sulfur dioxide (SO_2) CEM (which measures the inlet coker process gas from Exxon) is not operating, the minimum operating value recorded during the past 12-months shall be used. During the times YELP's main stack SO_2 CEM is not operating, the maximum operating value recorded during the past 12-months shall be used.

2. If the initial notification from Exxon indicates Exxon has exceeded the hourly sulfur-in-fuel limit, then YELP shall continue to comply with the ratio requirement described above in paragraph M.1 until such time as YELP is notified by Exxon that the Exxon refinery has met the hourly sulfur-in-fuel limitation for 3 consecutive hourly periods.

3. If the initial notification from Exxon indicates Exxon has exceeded the daily limit on the number of barrels of fuel oil fired, then YELP shall continue to comply with the ratio requirement described above in paragraph M.1 until such time as YELP is notified by Exxon that the Exxon refinery is in compliance with the daily limit on fuel oil firing.

4. YELP shall report to the Department each time it receives initial notification by Exxon as referenced above in paragraph M.1, M.2, and M.3. The report shall be

submitted with the emission report to the Department required in Section III, Part D. of this permit, and shall include both the date and time YELP received initial and subsequent notification by Exxon, as referenced above in paragraph M.1, M.2, and M.3, as appropriate. The report shall also describe, in detail, the operating measures taken by YELP to meet the requirements in paragraphs M.1 through M.3**.**

N. YELP shall not have on site more than one limestone stockpile with a maximum capacity of up to 2,000 tons. YELP must implement best management practices to reduce wind-blown emissions on the limestone stockpile, which would include the use of water and/or chemical dust suppressant, material enclosures and/or concrete block wind barriers, and minimized material disturbance (ARM17.8.749).

O. YELP shall not have on site more than four inactive processed petroleum coke stockpiles with a maximum total capacity of 45,000 tons. YELP must implement best management practices to reduce wind-blown emissions, including wet surfactants and concrete block wind barriers (ARM17.8.749).

P. Total plant emissions for the listed pollutants shall not exceed the following (ARM 17.8.752 and 40 CFR 60, Subpart Da):

1. Main Stack

a. Sulfur Dioxide Emissions - 2476.0 tons/yr computed as a 12-month total at the end of each calendar-month; 8.160 tons/day, 680.0 maximum lb/hr; 620.0 lb/hr computed on a rolling 30-day average (0.777 lb/MMBtu).

b. Nitrogen Oxides - 1,396.0 tons/yr; 319.0 lb/hr computed on a rolling 30-day average (0.400 lb/MMBtu).

c. Opacity - 20% averaged over any 6 consecutive minutes.

d. Particulate Matter - 80.0 tons/yr; 438.4 lb/day; 18.26 lb/hr (0.023 lb/MMBtu).

e. Carbon Monoxide - 529.0 tons/yr; 2898.6 lb/day; 120.6 lb/hr.

f. Minimum of 92% SO_2 control for all boiler operating hours[1]. Percent control of SO_2 shall be determined according to the provision in 40 CFR 60, Subpart Da, Section 60.48a, except that the percent control is required for all boiler operating hours instead of the boiler operating days as identified in 40 CFR 60.

2. Coke Storage Facility and Loading

a. Particulate Matter - 18.1 tons/yr.

[1] "Boiler operating hour" means any time during a 60 minute clock hour in which a boiler operates.

b. Opacity - 20% averaged over any 6 consecutive minutes.

c. Baghouse filter emissions shall not exceed 0.01 grains per dscf.

3. Coke Unloading/Crushing/Processing Facility and Coke Barn

a. Opacity - 20% averaged over any 6 consecutive minutes.

b. Baghouse filter emissions shall not exceed 0.01 grains per dry standard cubic feet (gr/dscf).

4. Ash Silo and Unloading

a. Opacity - 20% averaged over any six consecutive minutes.

b. Baghouse filter emissions shall not exceed 0.01 gr/dscf.

5. Limestone Unloading, Crushing, and Conveying

a. Opacity - 20% averaged over any 6 consecutive minutes.

b. Baghouse filter emissions shall not exceed 0.01 gr/dscf.

6. Limestone Stockpile

a. Opacity - 20% averaged over any 6 consecutive minutes.

7. In addition, where applicable, all other federal emission limitations (ARM 17.8.340) shall be met, including, but not limited to, the following for the main stack:

a. SO_2 - Standard for sulfur dioxide contained in 40 CFR Part 60.43a.

b. NO_x - Standard for nitrogen oxides contained in 40 CFR Part 60.44a.

c. Particulate - Standard for particulate matter contained in 40 CFR Part 60.42a.

d. YELP is authorized to burn petroleum coke (solid fuel) and coker gas (gas fuel) (ARM 17.8.749).

8. YELP shall comply with the applicable requirements of 40 CFR Part 60.110b, as required (ARM 17.8.340 and 40 CFR Part 60.110b).

Q. YELP shall install and operate the following Continuous Emission Monitors/ Continuous Emission Rate Monitors (CEMs/CERMs) (ARM 17.8.340 and ARM 17.8.749):

1. Main Stack
   a. Opacity
   b. Sulfur Dioxide

c. Nitrogen Oxides
d. Oxygen
e. Carbon Monoxide
f. Volumetric Flow Rate

2. Coker Process Gas Flue

a. Sulfur Dioxide
b. Volumetric Flow Rate

Said monitors shall comply with all applicable provisions of 40 CFR 60, Subpart A - 60.5 through 60.13, Subpart Da - 60.46a through 60.49a, and Appendix B, Performance Specifications 1, 2, 3, and 4. Volumetric flow rate monitors shall comply with the requirements of Attachment 1, including Methods A-1 and B-1. (ARM 17.8.749 and 40 CFR 60, Subpart A, 40 CFR 60, Subpart Da, and 40 CFR 60, Appendix B).

R. Compliance with emission limits in Sections II.M, II.P.1, and, II.P.7 shall be determined by utilizing data taken from the CEMs listed in Section II.Q above, and as required by 40 CFR 60, Subpart Da, and other Department-approved sampling methods. Compliance with Section II.P.1.f. shall also include information gathered as required by Section III. Compliance with emission limits in Section II.P.2 through II.P.7 shall be determined by Department-approved sampling and done in accordance with the Montana Source Test Protocol and Procedures Manual. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor. The above does not relieve YELP from meeting any applicable requirements of 40 CFR 60, Appendices A and B, or other stack testing that will be required by the Department. The Department shall require compliance stack testing at the YELP main stack, on a semi-annual basis for the first 2-years of operation, and annually thereafter. Testing will include, but is not limited to, the following air pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM, PM-10) and toxic air pollutants (TAPs).

Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department. All gaseous continuous emission monitors shall be required to comply with quality assurance/quality control procedures in 40 CFR Part 60, Appendix F and the CEM availability requirements in 40 CFR 60.47a. CEM systems are to be in operation at all times when the emission units are operating except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEM system is unable to meet minimum availability requirements, YELP shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. YELP shall submit the alternative monitoring plan for Department approval within 60 days after achieving the maximum production rate for the facility and not later than 180 days after initial startup (ARM 17.8.105, ARM 17.8.106, ARM 17.8.749, and ARM 17.8.340 and 40 CFR, Part 60).

S. Compliance testing and continuous monitor certification shall be as specified in 40 CFR Part 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be approved by the Department

prior to commencement of testing. Certification of all CEMS/CERMS shall be conducted annually. The annual monitor certification can coincide with the required compliance stack testing (ARM 17.8.106 and ARM 17.8.749 and 40 CFR, Part 60).

T. YELP shall conduct source testing and demonstrate compliance with the limits contained in Section II.P, except Section II.P.3, every 4-years or according to another testing schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

U. Bypassing any pollutant control device during operation except as expressly provided for in 40 CFR 60.46a and ARM 17.8.110, Malfunctions, is prohibited.

V. YELP shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

W. YELP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

X. All access roads shall use either paving or chemical dust suppression to limit excessive fugitive dust, with water suppression as a back-up measure to maintain compliance with the reasonable precautions' limitations in Section II.W. Construction, stockpiling, and material-moving activities shall use reasonable precautions for limiting excessive fugitive dust from impacting nearby residential and commercial establishments (ARM 17.8.308 and ARM 17.8.749).

Y. YELP shall not cause or authorize the discharge into the atmosphere of emissions from production, handling, or transportation which exhibit an opacity of 20% or greater (ARM 17.8.308).

Z. The Department may require further testing (ARM 17.8.105).

Section III: Monitoring and Operational Reporting Requirements

A. YELP shall install, operate and maintain the applicable CEMs/CERMs listed in Section II.Q. Emission monitoring shall be subject to 40 CFR 60, Subpart Da, Appendix B (Performance Specifications 1, 2, 3, 4, and 6) and Appendix F (Quality Assurance/Quality Control) provisions. Any stack testing requirements that will be required (in Section II.R) shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements Provisions (ARM 17.8.106 and ARM 17.8.749).

B. YELP shall analyze the weight percent sulfur and heating value (BTU/lb) of the solid petroleum coke fuel on a monthly basis when the boilers are operating. Twice per month YELP shall analyze the coker gas stream to facilitate the F-Factor determination when the boilers are operating. Analyses procedures and methods shall follow 40 CFR 60, Subpart Da.48a, including Reference Method 19 (ARM 17.8.749, 40 CFR 60, Subpart Da, 40 CFR 60, Appendix A).

C. Beginning with the first quarter of 1998, YELP shall submit quarterly emission reports. Emission reporting for sulfur dioxide from the main stack and Exxon coker process gas shall consist of hourly and 24-hour calendar day totals for each calendar month. The reports, which are due 30 days after the end of each period, shall also include the following (ARM 17.8.749):

1. Source or unit operating time during the reporting period and daily petroleum coke fuel and limestone consumption.

2. Monitoring down time which occurred during the reporting period.

3. A summary of excess emissions for each pollutant and averaging period identified in Section II.P.1.a through II.P.1.f.

4. Emission estimates for sulfur oxides and reduced sulfides from material balance, engineering calculation data, and any emission testing. Report of sulfur and BTU content from petroleum coke fuel analysis on a daily basis.

5. Reasons for any emissions in excess of those specifically allowed in Section II. P.1 with mitigating measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

D. YELP shall keep the Department apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. In addition to applicable requirements of 40 CFR 60, Subpart A - 60.7, the following reports and recordkeeping shall be required:

1. Notification of dates of cessation of construction, restarts of construction, startups, and monitor certification tests (ARM 17.8.340).

2. Commencement of construction of the coke storage stockpiles within 15 days of construction (ARM 17.8.749).

3. All source tests shall be conducted in compliance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

4. Copies of emissions report, excess emissions and all other such items mentioned in Section III shall be submitted to both the Billings Regional Office and the Helena office of the Department (ARM 17.8.749).

5. Monitoring data shall be maintained for a minimum of 5 years at the YELP facility (ARM 17.8.749).

6. All data and records that are required to be maintained must be made available upon request by representatives of the Department, the U.S. Environmental Protection Agency, and the Yellowstone County Air Pollution Control Agency (ARM 17.8.749).

E. The Department retains the ability to require ambient monitoring in the future if the Department believes there might be a violation of a standard attributed to YELP (ARM 17.8.105).

F. Operational Reporting Requirements

1. YELP shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall include the following, and be in units as required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or verifying compliance with permit limitations (ARM 17.8.505).

   a. Tons of petroleum coke consumed in the boilers.
   b. Gallons of diesel consumed in the boilers.
   c. Million standard cubic feet coker gas consumed in the boilers.
   d. Tons of limestone received.
   e. Tons of ash removed from the ash silos.
   f. Total tons of petroleum coke loaded out at coke load-out silo.
   g. Total tons of SO_2 in the Coker Process Gas.
   h. Annual average percent sulfur in the petroleum coke.
   i. Annual average million BTU per pound for the petroleum coke.
   j. Total tons of petroleum coke crushed/processed in the Coke Unloading/Crushing/Processing Plant.
   k. Total tons of coke stored in the Coke Barn.
   l. Total tons of off-site coke transported to and stored at the Exxon Refinery coke storage area.
   m. Total tons of petroleum coke processed on site (crushed, stored and handled)
   n. Total tons of petroleum coke stored in outside stockpiles.
   o. Total tons of limestone stored in outside stockpile.

2. YELP shall supply the Department with annual processing/storage information for off-site petroleum coke. YELP shall document, by month, the total amount of off-site coke processed/stored at the facility. By the 25 of each month, YELP shall total the monthly coke transported and dumped at the Exxon Refinery coke storage area, the total amount of coke processed in the Coke Unloading, Crushing, Processing facility, and the total amount of coke stored in the Coke Barn during the previous 12 months to verify compliance with the limitation in Section II.J.1 and II.J.2. A written report of compliance verification shall be submitted along with the annual emissions inventory (ARM 17.8.749).

3. YELP shall maintain records of the date of all transfers of off-site petroleum coke to the Exxon Refinery coke storage area to demonstrate compliance with Section II.J.2 (ARM 17.8.749).

4. All records compiled in accordance with this permit must be maintained by YELP as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department and must be submitted to the Department upon request (ARM 17.8.749).

5. YELP shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include ***the addition of a new emissions unit,*** change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation. The notice must be submitted to the Department, in writing, 10 days prior to startup or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(l)(d) (ARM 17.8.745).

SECTION IV: General Conditions

A. Inspection – YELP shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if YELP fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving YELP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq.*, MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefor, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by YELP may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

ATTACHMENT 1

PERFORMANCE SPECIFICATIONS FOR STACK FLOW RATE MONITORS,
(Includes Methods A-1 and, B-1)

METHOD A-1
INSTALLTION AND INITIAL CERTIFICATION
IN-STACK OR IN-DUCT FLOW MONITORS

1.0 FLOW MONITOR INSTALLATION AND MEASUREMENT LOCATION

Install the flow monitor in a location that provides representative volumetric flow for all operating conditions. Such a location provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of 40 CFR Part 60, Appendix A, to establish a proper location for the flow monitor.

The Department of Environmental Quality (Department) recommends (but does not require) performing a flow profile study following the procedures in 40 CFR Part 60, Appendix A, Test Method 1, Section 2.5 to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR Part 60, Appendix A, Test Method 1, Section 2.5 may be used even if the flow measurement location is greater than or equal to two equivalent stack or duct diameters downstream or greater than or equal to 2 duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this Method, then the Department recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. The Department also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.1 Acceptability of Flow Monitor Location

The installation of a flow monitor is acceptable if: (1) the location satisfies the minimum siting criteria of Method 1 in Appendix A to 40 CFR Part 60 (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from, a flow disturbance); (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions); and (3) the flow monitor satisfies the performance specifications of this Method. If the flow monitor is installed in a location that does not satisfy these physical criteria, but the monitor achieves the performance specifications of this Method, then the Department may certify the location as acceptable.

1.2 Alternative Flow Monitoring Location

Whenever the flow monitor is installed in a location that is greater than or equal to two stack or duct diameters downstream and greater or equal to one-half diameter upstream from a flow disturbance, and/or in a location that is acceptable based on a flow profile study, but nevertheless the monitor does not achieve the performance specifications of this Method, perform another flow profile study (the procedures described in 40 CFR Part 60, Appendix A, Method 1, Section 2.5 may be used) to select an alternative flow monitoring installation site.

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Department may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

If no location exists that satisfies the physical siting criteria in section 1.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Department for an alternative method for monitoring flow.

2.0 FLOW MONITOR EQUIPMENT SPECIFICATIONS

2.1 Instrument Span - General Requirements

In implementing Section 2.1.1 of this Method, to the extent practicable, measure at a range such that the majority of readings obtained during normal operation are between 25 and 75 percent of full-scale range of the instrument.

2.1.1 Instrument Span for Flow Monitors

Select the full-scale range of the flow monitor so it is consistent with Section 2.1 of this Method and can accurately measure all potential volumetric flow rates at the flow monitor installation site. Establish the span value of the flow monitor at a level which is approximately 80% of the full-scale range and 125% of the maximum expected flow rate. Based on the span value, establish reference values for the calibration error test in accordance with Section 2.2.1.

If the volumetric flow rate exceeds the flow monitor's ability to accurately measure and record values, adjust the full-scale range, span value, and reference values as described above and in Section 2.2.1. Record the new span value and report the new span value and reference values as parts of the results of the calibration error test required by Method B-1. Whenever the span value is adjusted, use reference values for the calibration error test based on the new span value.

2.2 Flow Monitor Design for Quality Control Testing

Design all flow monitors to meet the applicable performance specifications of this Method.

2.2.1 Flow Monitor Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal); and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of: (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system; or (2) the flow monitoring system from, and including, the transducer through and including the data acquisition and handling system.

2.2.2 Flow Monitor Interference Check

Design and equip each flow monitor in a manner to minimize interference due to moisture. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

Design and equip each differential pressure flow monitor to provide: (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on a least a daily basis to prevent velocity sensing interference; and (2) a means for detecting leaks in the system on a least a quarterly basis (manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3.0 FLOW MONITOR PERFORMANCE SPECIFICATIONS

3.1 Flow Monitor Calibration Error

The calibration error of flow monitors shall not exceed 3.0 percent, based upon the span of the instrument as calculated using Equation A-1 of this Method.

3.2 Flow Monitor Relative Accuracy

Except as provided in this Section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 20.0 percent. For affected units where the average of the flow monitor measurements of gas velocity during the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed +/- 2.0 fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

4.0 DATA ACQUISITION AND HANDLING SYSTEMS

Automated data acquisition and handling systems shall: (1) read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous record of all measurements and required information in an electronic format specified by the Department and capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from a pollutant concentration monitor and a flow monitor to produce a continuous readout of pollutant mass emission rates in pounds per hour.

Data acquisition and handling systems shall also compute and record monitor calibration error.

5.0 INITIAL FLOW MONITOR CERTIFICATION TESTS AND PROCEDURES

5.1 Flow Monitor Pretest Preparation

Install the components of the continuous flow monitor as specified in Sections 1.0, 2.0, and 3.0 of this Method, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instruction. Operate the unit(s) during each period when measurements are made.

5.2 7-Day Calibration Error Test for Flow Monitors

Measure the calibration error of each flow monitor according to the following procedures.

Introduce the reference signal corresponding to the values specified in Section 2.2.1 of this Method to the probe tip (or equivalent), or to the transducer. During the seven-day certification test period, conduct the calibration error test once each day while the unit is operating (as close to 24-hour intervals as practicable). Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-1 of this Method.

Do not perform any corrective maintenance, repair, replacement or manual adjustment to the flow monitor during the seven-day certification test period other than that required in the monitor operation and maintenance manual. If the flow monitor operates within the calibration error performance specification, (i.e., less than or equal to three percent error each day and requiring no corrective maintenance, repair, replacement or manual adjustment during the seven-day test period) the flow monitor passes the calibration error test portion of the certification test. Whenever automatic adjustments are made, record the magnitude of the adjustments. Record all maintenance and required adjustments. Record output readings from the data acquisition and handling system before and after all adjustments.

5.3 Flow Monitor Relative Accuracy

Within 90 days of installation, concurrent relative accuracy test audits may be performed by conducting simultaneous SO_2 concentration and volumetric flow relative accuracy test audit runs, or by alternating an SO_2 relative accuracy test audit run with a flow relative accuracy test audit run until all relative accuracy test audit runs are completed. Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling. For

each SO_2 pollutant concentration monitor and each flow monitor, calculate the relative accuracy with data from the relative accuracy test audits.

Perform relative accuracy test audits for each flow monitor at normal operating load expressed in terms of percent of flow monitor span. If a flow monitor fails the relative accuracy test, the relative accuracy test audit must be repeated.

Complete each relative accuracy test audit within a seven-day period while the unit is operating in a normal condition. Do not perform corrective maintenance, repairs, replacements or adjustments during the relative accuracy test audit other than as required in the operation and maintenance manual.

5.3.1 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy in accordance with the procedure and equations specified in Section 6 of this Method.

5.3.2 Reference Method Measurement Location

Select a location for reference method measurements that is: (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Method 1 (or 1A) of 40 CFR Part 60, Appendix A for volumetric flow, except as otherwise indicated in this Section.

5.3.3 Reference Method Traverse Point Selection

Select traverse points that: (1) ensure acquisition of representative samples of pollutant concentration, moisture content, temperature, and flue gas flow rate over the flue cross section; and (2) meet the requirements of Method 1 (or 1A) (for volumetric flow), and Method 4 (for moisture determination) in 40 CFR part 60, Appendix A.

5.3.4 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the moisture content, temperature, and flue gas flow rate from the unit and can be correlated with the flow monitor measurements. Conduct any moisture measurements that may be needed simultaneously with the flue gas flow rate measurements. To properly correlate volumetric flow rate data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

5.3.5 Correlation of Reference Method and Continuous *Emission Monitoring System*

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, and temperature basis (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also consider the response time of the flow monitoring system to ensure comparison of simultaneous measurements. For each relative accuracy test audit run, compare the measurements obtained from the flow monitor against the corresponding reference method values. Tabulate the paired data in a table similar to the one shown in Figure 1.

5.3.6 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required relative accuracy test audit. Conduct each set within a period of 30 to 60 minutes.

The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy is greater than or equal to nine. Report all data, including the rejected data, and reference method test results.

5.3.7 Reference Methods

The following methods from 40 CFR, Part 60, Appendix A or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 (or 2A, 2C, or 2D as appropriate) for velocity; and Method 4 for moisture.

6.0 CALCULATIONS

6.1 Flow Monitor Calibration Error (Drift)

For each reference value, calculate the percentage calibration error based upon span using the following equation:

(EQ.A-1)

$$CE = \frac{(R - A)}{S} \times 100$$

Where:

CE = Calibration error;
R = Low or high level reference value specified in Section 2.2.1 of this Method;
A = Actual flow monitor response to the reference value; and
S = Flow monitor span.

Whenever the flow rate exceeds the monitor's ability to measure and record values accurately, adjust the span to prevent future exceedances. If process parameters change or other alterations are made so the expected flue gas velocity may change significantly, adjust the span to assure the continued accuracy of the monitoring system.

6.2 Relative Accuracy for Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 1. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

6.2.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, of a data set as follows.

(Eq. A-2)

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i$$

Where:

n=Number of data points

$\sum_{i=1}^{n} d_i$ = Algebraic sum of the individual differences d_i

d_i = The difference between a reference method value and the corresponding continuous flowrate monitoring system value (RM_i-FR_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

6.2.2 Standard Deviation

Calculate the standard deviation, S_d of a data set as follows:

(Eq. A-3)

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

6.2.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

(Eq. A-4)

$$CC = t_{0.025}\frac{S_d}{\sqrt{n}}$$

where:

$t_{0.025}$ = *t value (see Table 2)*

TABLE 2 T-VALUES

n-1	^{t}0.025	n-1	^{t}0.025	n-1	^{t}0.025
1…….	12.706	12	2.179	23	2.069
2.....	4.303	13	2.160	24	2.064
3.....	3.182	14	2.145	25	2.060
4.....	2.776	15	2.131	26	2.056
5.....	2.571	16	2.120	27	2.052
6.....	2.447	17	2.110	28	2.048
7.....	2.365	18	2.101	29	2.045
8.....	2.306	19	2.093	30	2.042
9.....	2.262	20	2.086	40	2.021
10.....	2.228	21	2.080	60	2.000
11.....	2.201	22	2.074	>60	1.960

6.2.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

(Eq. A-5)

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} x\,100$$

where:

RM = Arithmetic means of the reference method values.

x đ x= The absolute value of the mean difference between the reference method values and the corresponding continuous flow monitor values.

x cc x= The absolute value of the confidence coefficient.

FIGURE 1.-RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date & Time	Flow rate (Normal) (scf/hr)*		
		RM	M	Diff
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
Mean or mean of differences				
		Confidence coefficient		
		Relative accuracy		

* Make sure RM and M are on a consistent moisture basis.

METHOD B-1

ON-GOING QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES
FOR IN-STACK AND IN-DUCT FLOW MONITORS

1.0 FREQUENCY OF FLOW MONITOR TESTING

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this Method in Table 1.

1.1 Daily Flow Monitor Assessments

For each flow monitor, perform the following assessments during each day in which the unit is operating. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

1.1.1 Calibration Error Test for Flow Monitors

Test, compute, and record the calibration error of each flow monitor at least once on each operating day. Introduce the reference values (specified in section 2.2.1 of Method A-1) to the probe tip (or equivalent) or to the transducer. Record flow monitor output from the data acquisition and handling system before and after any adjustments to the flow monitor. Keep a record of all maintenance and adjustments. Calculate the calibration error using Equation A-1 in Method A-1.

1.1.2 Flow Monitor Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2 of Method A-1 at least once per operating day (when the unit(s) operate for any part of the day).

1.1.3 Flow Monitor Re-calibration

Adjust the calibration, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification for the flow monitor in Method A-1. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective.

1.1.4 Flow Monitor Out-of-Control Period

An out-of-control period occurs when either the low or high level reference value calibration error exceeds 6.0 percent based on the span value for five consecutive daily periods or 12.0 percent for any daily period. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out of control if two or more complete and valid readings are obtained during that hour. An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed. During any period the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.1.5 Flow Monitor Data Recording

Record and tabulate all calibration error test data according to month, day, clock hour, and magnitude in scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted flow rate measured in the calibration error test prior to resetting the calibration; or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage; and (2) malfunction of each RTD, transceiver, or equivalent.

1.2 Quarterly Flow Monitor Assessments

For each flow monitor, conduct a quarterly stack velocity and flow rate check by performing a velocity traverse and visual inspection of the pitot tubes. Perform the following assessments during each calendar quarter in which the unit operates. This requirement is effective as of the calendar quarter following the calendar quarter in which the flow monitor is provisionally certified.

1.2.1 Flow Monitor Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each unit operating quarter. Conduct the leak checks no less than two months apart.

1.2.2 Flow Monitor Flow Rate Check

Once during each operating quarter, and for each flow monitor, perform a flow rate check by completing a single velocity traverse, calculating the associated average flow rate, and comparing the average flow with the concurrent flow measured by the continuous flow monitor. The flow rate check shall be performed at normal operating rates or load level. The flow rate check shall be performed in accordance with Section 5.3 of Method A-1 as appropriate for a single traverse. The difference (PD) between the average flow rate determined by the single velocity traverse and the continuous flow monitor shall not exceed 20 percent as determined by equation B-1. If the single velocity traverse fails to meet the 20% difference specification, the owner/operator may conduct an additional single velocity traverse or a complete Relative Accuracy Test Audit (RATA) in accordance with Section 5.3 of Method A-1 in order to demonstrate compliance with the 20% difference or 20% relative accuracy requirements.

$$PD = \frac{TF - FR}{TF} \times 100 \qquad \text{(Eq. B-1)}$$

Where:

PD = Percent Difference;
TF = Traverse Flow (scfh);
FR = Continuous Flow Monitor Flow (scfh); and
TF and FR are on a consistent moisture basis.

If the Relative Accuracy of the latest annual Relative Accuracy Test Audit (RATA) conducted pursuant to Section 1.3.1 is less than 10%, the single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the single velocity traverse flow rate check shall resume.

1.2.3 Flow Monitor Out-of-Control Period

An out-of-control period occurs when a flow monitor fails the quarterly flow rate check (the difference between the average flow rate determined by the velocity traverse and the continuous flow monitor exceeds 20%), the visual inspection of the pitot tube indicates pluggage or wear, or if a sample line leak is detected. The out-of-control period begins with the hour of the failed flow rate check, visual inspection, or leak check and ends with the hour of a satisfactory flow rate check, RATA, leak check, or cleaning or replacement of the pitot tube. During any period that the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.3 Annual Flow Monitor Assessments

For each flow monitor, perform the following assessments once annually. This requirement is effective as of the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

1.3.1 Flow Monitor Relative Accuracy Test Audit

For flow monitors, relative accuracy test audits shall be performed annually. The relative accuracy audit shall be performed at the normal operating rate or load level (with a minimum of nine paired velocity traverses). The relative accuracy test audit shall be conducted according to the procedures and specifications of Method A-1.

1.3.2 Flow Monitor Out-of-Control Period

An out-of-control period occurs under any of the following conditions: (1) the relative accuracy of a flow monitor exceeds 20.0 percent; or (2) for low flow situations ($\leq$10.0 fps), the flow monitor mean value (if applicable) exceeds +/- 2.0 fps of the reference method mean whenever the relative accuracy is greater than 20.0 percent. For flow relative accuracy test audits, the out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit. During any period the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

TABLE 1 - FLOW MONITOR QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily	**Quarterly**	**Annual**
Calibration Error (2 pt.)	X		
Interference (flow)	X		
Visual probe check		X	
Flow rate check (single traverse)		X[1]	
Leak (flow)		X[2]	
RATA (flow)			X

[1] The owner/operator has an option to perform a RATA if the quarterly flow rate check (single traverse) fails specifications. In addition, if the Relative Accuracy determined by the latest RATA is less than 10%, the quarterly single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the quarterly single velocity traverse flow rate check shall resume.

[2] The leak check requirement only applies to differential pressure flow rate monitors and does not apply to thermal or ultrasonic flow rate monitors.

Montana Air Quality Permit Analysis
Yellowstone Energy Limited Partnership
MAQP #2650-09

I. Introduction/Process Description

Yellowstone Energy Limited Partnership (YELP) owns and operates a petroleum/coke-fired co-generation facility. The facility is located due east of the Exxon Tank Farm, on the south side of the railroad mainline and directly south of the Exxon Refinery and Montana Sulphur & Chemical Company facilities in Billings, Montana. The legal description is the NE ¼ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana

A. Permitted Equipment

This permit covers the following equipment at the facility:

1. 2 circulating fluidized bed combustion boilers and cyclonic separators;
2. Steam turbine (1);
3. Electrical generator (1);
4. Petroleum coke handling system - coke hopper, pneumatic conveyors and surge bin with associated baghouse particulate control;
5. Coker process gas pneumatic duct system;
6. Limestone handling systems - truck dump, crushing, conveying storage silo, and associated baghouse particulate control (2);
7. 2 main baghouses venting through one (1) stack;
8. Ash handling system - storage silo, conveyors, and load-out;
9. 199.0 foot stack (1);
10. Air-cooled condensing unit (1);
11. Petroleum coke unloading/crushing/processing plant and associated baghouse;
12. Outside Petroleum coke storage piles (4);
13. Outside limestone storage pile (1);
14. Coke load-out silo and associated baghouses; and
15. Coke barn – crushed/processed petroleum coke storage and handling.

B. Source Description

The Yellowstone Power Plant is a petroleum/coke-fired co-generation facility providing both electrical power and steam. The electricity is sold to Northwestern Energy and the steam is sent to Exxon. The facility is also designed to burn the coker unit process gas from the Exxon facility.

The design of the facility is for 65.0 gross megawatts and 140,000 lbs/hour of steam. The single turbine has been designed to produce a minimum of 65.0 gross megawatts and a maximum, that is probably in the range of 68.0 gross megawatts. The parasitic load will vary from 3 to 7 megawatts; therefore, the expected net megawatt output will range from 58 to 65 megawatts. YELP will have the capability of sending approximately 300,000 lb/hour of steam to the Exxon refinery. If this amount of steam is sent to Exxon, the megawatt rate will be decreased.

The facility consists of two Tampella Power circulating fluidized bed (CFB) boilers with 15,534 square feet of superheater heat surface area each, and 8,837 square feet of water wall heat surface area, each built in 1994. The nominal rating is 911 x 10^6 BTU/hr (boiler capacity combined). The maximum operating rate for both boilers combined is theoretically as high as 1,300 x 10^6 BTU/hr on a short-term basis. The CFB boilers use limestone to control the SO_2 emissions.

The CFB boilers will combust fuel in a series of circulating beds of limestone aggregate, which is fluidized by the upward flow of combustion air and the gaseous products of combustion. Primary combustion air and coker process gas are introduced at the bottom of each combustor. Each boiler is designed to fire 14.5 tons per hour of fluid petroleum coke plus the coker process gas. The boilers may fire up to 86.5 tons of fluid petroleum coke per hour, but it is expected the design of the plant and emission limits would prevent this from occurring on a regular basis. This higher rate could also only occur if the BTU value and the sulfur content of the petroleum coke were much lower than the expected average. If one CFB boiler is down, the other operating CFB combustor can accept and fire the coker process gas. This twin-system design enhances the on-stream capability and operational reliability of the plant to accept and treat the Exxon coker CO process gas stream.

Flue gases from the CFB combustors are recycled by cyclone collectors, which return the collected material to the fluidized bed level. Secondary combustion air is introduced at levels above the fluidized bed to ensure complete combustion. Sulfur and nitrogen oxides (SOx, NOx) emissions are controlled via the combustion process. Calcium carbonate (limestone), which is added to the CFB combustors, acts as a sorbent of SOx while atmospheric CFB boiler design limits NOx. The combusted flue gases also contain particulates that are filtered or scrubbed in a high efficiency baghouse before venting to the plant stack.

The YELP facility also contains equipment for receiving petroleum coke from Exxon, Exxon coker gas, and limestone; load-out of petroleum coke; crushing of coke; processed petroleum coke storage (in outside stockpiles and within the storage barn); crushing of limestone; storage of crushed limestone; storage of off-site coke; storage of ash; and removal and transportation of ash from the boilers.

C. Permit History

The PSD MAQP **#2650** was issued December 13, 1991, for the construction of an electrical power generating and steam co-generation facility. The application was originally submitted on July 6, 1990. Because the facility was considered a major source, the application was subject to New Source Review and the requirements of the Prevention of Significant Deterioration (PSD) program. Billings Generation Inc. (BGI) was applicant, with Bison Engineering Inc. as the environmental consultants performing the air quality permitting analyses. The application was deemed complete on November 8, 1991, contingent upon acceptable modifications to existing Exxon Refinery permits because offsets of SO_2 emissions from the Exxon facility were required before construction of the BGI facility could be authorized.

The proposed petroleum coke-fired power plant originally had a nameplate rating of 49.5 megawatts and would produce approximately 42 net megawatts of electrical power

generation. Gaseous emissions and particulates from the Exxon coker process unit would also be fired in the BGI combustors. The BGI power plant provides co-generated steam energy for the Exxon Refinery.

The proposal included construction of the BGI facility and some modifications at the Exxon Refinery coker-CO boiler. The modifications to the existing coker-CO boiler included the installation of flue gas duct work to divert the coker unit process gas to the BGI facility. Fluid coke, also produced by that unit, would be pneumatically fed to the BGI facility. Steam pipelines between BGI and Exxon facilities were also required.

An air cooled condenser (ACC), along with a service cooling water-cooling tower, is used by the BGI power plant. Water resource demand at the plant is minor with an ACC system. Potable water requirements, as well as service cooling water, are available from the local water users association.

The proposal indicated that an additional 99 tons per year of SO_2 emissions reduction may be realized from the Exxon Refinery. The source of this reduction at the refinery would come from high-sulfur fuel oil burning. The annual SO_2 offset or net SO_2 reduction that can be expected from this overall project was 238 tons (BGI and Exxon coker gas).

Listed below is the summary of the net emission rates for the BGI facility and proposed emission changes at the Exxon Refinery:

Source	SO_2	NO_x	CO	PM	PM-10	VOC	TAPs
BGI Main Stack	2476	1396	529	80.0		11.2	
Coke Handling				12.8	5.3		
Ash Handling				1.1			X
Limestone Handling				0.9			
Exxon Coker Process Gas	-2714*						
Exxon Coker CO-Boiler	0						
Exxon Refinery Fuel Oil Burning	[-99**]						
Total (tons)	-238	1396	529	94.8	5.3	11.2	

NOTES:
TAP = Toxic Air Pollutants
* Average of 1988 - 1990 Years
[**] Expected, but not committed from hourly sulfur-in-fuel limitation - these offsets were modified by MAQP #2650-02 and are now enforceable.
Emission decreases of NO_x, CO, and PM/PM-10 are not quantified by federally enforceable emission limitations or conditions at the Exxon Refinery. However, emissions increases at BGI, from the decreases at Exxon, have been accounted for at the (BGI) main stack.

PSD Minor Source Baseline Date - As a result of this first PSD application for the Billings area, the minor source baseline date is now triggered for particulates, SO_2, and NO_x. The PSD application was deemed complete on November 8, 1991.

MAQP **#2650-01** was issued March 11, 1992. Billings Generation Inc. (BGI) requested a modification to MAQP #2650 to support SO_2 emissions reductions in conjunction with the EXXON refinery and permit modification #1564-03. The modified BGI permit addressed EPA concerns in the original permit (#2650). The request was addressed under the provisions of Subchapter 11, Administrative Rules of Montana (ARM) 16.8.1113(1)(b). The changes addressed verification of required offsets from the Exxon facility, contingency measures if the offsets are not met and additional modeling performed to verify that the project would not cause significant impacts to the NAAQS.

The overall SO_2 offset for the proposed project is now as follows:

BGI Main Stack	2476 tpy
Exxon Coker process gas	- 2714 tpy
Exxon Refinery Fuel Oil Burning	- 100 tpy
TOTAL	- 338 tpy

No other air pollutant emission rates were affected by this permit modification action.

Permit modification **#2650-02** was issued March 25, 1993 to change the design of the facility from one main baghouse controlling the boilers exhausting through two stacks, to two baghouses exhausting through one stack.

Permit Alteration **#2650-03** was issued on December 23, 1995, to accomplish the following:

1. The permittee was changed from BGI to YELP. The plant name is to be the Yellowstone Power Plant and will be operated by Rosebud Operating Services, Inc. (ROSI).

2. The alteration also allowed YELP to burn other petroleum cokes and cat slurry oil in the boilers as alternative fuels. The permit application did not contain a request for an increase in emissions.

3. Changes were made to the permit to make it consistent with the stipulation signed by YELP for its facility in Billings. The stipulation was required as part of the Billings SIP for SO_2 emissions to ensure the allowable emission rates for the facility were capped. The changes included converting the monthly reporting requirements to quarterly and modifying the flow rate monitors.

4. YELP also requested the description of the facility be changed to include a description of the current design. The original facility was designed to produce steam and use a portion of the steam to drive the parasitic load in the plant. With this permit application, YELP identified that the load in the plant will no longer be driven by steam. The equipment in the plant will be driven by electricity. Based on this change, YELP presented that the efficiency of the facility would be increased.

5. The Department of Environmental Quality – Air Resources Management Bureau (Department) removed the lb/MMBtu requirements from some of the limits contained in Section II.I. Some lb/MMBtu values are still needed to ensure compliance with applicable requirements and to identify the possible changes in the

boiler operating rate. The Department also clarified the requirements of Section II.I.5. to identify the requirement references more clearly.

6. The Department has removed the requirement of limiting the sulfur content of the petroleum coke. It is YELP's responsibility to ensure, regardless of the sulfur content of the fuel, the 92% control efficiency is met and the SO_2 emission limits are met.

Permit modification #2650-04 was issued on May 18, 1996. The permit modification changed the coke sampling and analysis requirements for the facility. Previously, YELP had been required to sample the coke supply to the boilers on a daily basis for sulfur content and heating value. YELP showed, by this sampling, that there was little variability in the sulfur content of the coke, and the Department agreed that weekly sampling would be sufficient to demonstrate compliance with applicable requirements. This modification did not result in an increase in the emissions of any pollutant from the facility. **MAQP #2650-04** replaced MAQP #2650-03.

On November 3, 1999, YELP submitted a complete permit application to alter MAQP #2650-04. The permit alteration involved the addition of an enclosed petroleum coke unloading/crushing/processing plant and a processed petroleum coke storage and handling building (Coke Barn) to the existing permitted equipment. Further, YELP requested an extension of time, under the general permit conditions, to install the Cat Slurry oil tank. **MAQP #2650-05** replaced MAQP #2650-04.

On January 12, 2000, the Department issued MAQP #2650-05; however, MAQP #2650-05 contained referencing errors which needed to be corrected prior to issuance of the Title V operating permit for the YELP facility. Therefore, the Department issued a modification to MAQP #2650-05 to correct improper referencing. **MAQP #2650-06** replaced MAQP #2650-05.

On June 9, 2000, the Department received, from YELP, a request to modify MAQP #2650-06. The permit modification request involved changing the solid petroleum coke sampling frequency (sulfur and heat content) from once per week to once per month.

Because YELP demonstrated to the Department's satisfaction that monthly sampling would be adequate for solid petroleum coke sampling and in accordance with ARM 17.8.733, the Department modified permit condition III.B. However, to facilitate the F-Factor determination (40 CFR 60, Method 19), the Department required coker gas sampling twice per month as indicated in Section III.B.

Further, on October 2, 2000, the Department received another modification request from YELP. The second modification request involved changing permit conditions to allow for the processing (crushing, handling, and storage) of petroleum coke in the Limestone Unloading, Crushing, and Conveying Facility. Under MAQP #2650-05, YELP was permitted to crush, handle, and store up to 240,900 tons/yr of petroleum coke in a yet to be constructed on-site Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility. The petroleum coke processing limit of 240,900 tons/yr, as previously discussed, was established to limit potential particulate emissions from the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility to a level less than the New Source Review Prevention of Significant Deterioration (NSR/PSD) program significance level for

total PM and PM_{10}. The analysis, conducted to establish the limit, considered several factors including baghouse control and indoor processing.

Because the existing Limestone Unloading, Crushing, and Conveying Facility incorporates the same control options as the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility, the Department determined that processing a maximum combined total of 240,900 tons of petroleum coke per year in the Limestone Unloading, Crushing, and Conveying Facility and/or the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility will not increase potential PM_{10} emissions. The request was accomplished under ARM 17.8.705(1)(r) (later changed to ARM 17.8.743).

Finally, on February 12, 2001, the Department received an additional modification request. This request involved dumping up to 35,000 tons of coke, to be used in YELP operations, at the existing Exxon Refinery petroleum coke pile.

The Department considered this modification request to be part of the same activity permitted under MAQP #2650-05. As previously discussed, the coke processing limit applied to the facility under MAQP #2650-05 was established to keep YELP out of an NSR/PSD permitting action by limiting coke processing such that potential total PM and PM_{10} emissions would be less than NSR/PSD significance. Because this permit modification request was considered part of the same activity, and because additive potential emissions would increase total project emissions to a level greater than the NSR/PSD permitting threshold for total PM and PM_{10}, YELP would be required to go through an NSR/PSD permitting action. However, because YELP still preferred to stay out of NSR/PSD review, the Department placed additional permit conditions which, in connection with those established in MAQP #2650-05, limited potential emissions to a level less than NSR/PSD significance. Thus, NSR/PSD review was not required for the proposed permit action**. MAQP #2650-07** replaced MAQP #2650-06.

On May 24, 2012 the Department received an application from YELP to modify MAQP #2650-07 to remove the Cat Slurry Oil Tank from the permit and to add permanent outside storage of petroleum coke fuel. Additional information was received on June 4, 2012 to complete the application. The Cat Slurry Oil Tank was permitted under MAQP #2650-05 but was never installed. There are no plans to construct this source in the future.

Since 2002, YELP has requested and received approval of three de minimis requests to temporarily store processed petroleum coke fuel outside of the coke barn to provide a reserve fuel supply to the two circulating fluidized bed combustion boilers (CFBCs) in the event of an extended coke supplier outage. The de minimis requests were approved on December 7, 2002 for 5,000 tons; July 8, 2004 for 25,000 tons; and, May 3, 2011for 17,000 tons. On October 25, 2005, YELP also received approval of a de minimis request to temporarily store 2,000 tons of limestone in a pile located adjacent to the coke barn. Addition of a coke load-out silo was also requested in a de minimis request and approved on February 10, 2011 respectively.

YELP has continued to store petroleum coke and limestone in outside storage piles on site. On May 24, 2012 YELP submitted an application to modify MAQP #2650-07 to include the construction of permanent on-site storage areas for up to 45,000 tons of processed petroleum coke fuel. Correspondence received on June 12, 2012 requested that the permit also include construction of a permanent outside storage area for up to 2,000

tons of limestone. The current permit action includes permanent outside storage areas for up to 45,000 tons of petroleum coke fuel, a storage area for up to 2,000 tons of limestone, and a coke load-out silo. Additionally, the current permit action updates the rule references, permit format, and the emissions inventory. **MAQP #2650-08** replaces MAQP #2650-07.

D. Current Permit Action

On January 23, 2020, the Department received an Administrative Amendment (AA) request from YELP to remove the ambient air quality monitoring requirements at Johnson Lane from the permit. Additional documentation supporting this request was received on July 23, 2020. YELP's AA request demonstrated that ambient monitoring at Johnson Lane has:

- Met the permit requirement of monitoring for a minimum of 2 years after maximum production which was achieved in 1996;
- Complied with the national and Montana ambient air quality standards for SO_2 since 1995, which includes the previous and 2010 new versions of the national ambient air quality standard with monitored values from 2017 all being less than 65 percent of the NAAQS;
- Met the data quality and completeness requirements for an ambient monitoring station; and
- Demonstrated that while YELP SO_2 emissions continue to remain steady, Billings-wide SO_2 emissions have been declining since 2010.

The Department concurs that monitoring is no longer necessary since the facility has:

- Monitored ambient impacts below 65 percent of the SO_2 standards during the past 3 years;
- The area no longer has a known air quality problem;
- Permit conditions pertaining to SO_2 at YELP are enforceable and compliance is regularly demonstrated; and
- The Department is confident that emissions are accurately characterized in the permit.

YELP requested discontinuing ambient air monitoring at the Pine Hills site in 2009. The Department approved discontinuing ambient air monitoring at the Pine Hills site and removed the Pine Hills monitoring conditions when renewing the operating permit (OP2650-02). However, YELP's MAQP was never updated. The current permit action updates the permit to reflect that no ambient air monitoring is required at the Pine Hills site, or the Johnson Lane site by the Department at this time. The Department retains the ability to require ambient monitoring in the future if the Department believes there might be a violation of a standard attributed to YELP. **MAQP #2650-09** replaces MAQP #2650-08.

E. Additional Information

Additional information, such as applicable rules and regulations, Best Available Control Technology (BACT)/Reasonably Available Control Technology (RACT) determinations,

air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the Department of Environmental Quality (Department). Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   YELP shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide

4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}
11. ARM 17.8.230 Fluoride in Forage

YELP must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, YELP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

7. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). YELP is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts.

a. 40 CFR 60, Subpart A – General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below:

b. 40 CFR 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants. In order for a crushing plant to be subject to this subpart, the facility must meet the definition of an affected facility and, the affected equipment must have been constructed, reconstructed, or modified after August 31, 1983. YELP owns and operates a coke crushing, processing, storage, and handling facility. Because the permitted equipment does not meet the definition of a non-metallic mineral crushing plant, or any other applicable NSPS source, the coke crushing, processing, storage and handling plant is not subject to NSPS requirements.

b. 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units. This subpart applies to each electric utility steam generating unit that is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)) heat input of fossil fuel and for which construction, modification, or reconstruction is commenced after September 18, 1978. The subpart contains standards for particulate, SO_2 and NO_x. The boilers at YELP's facility are subject to Subpart Da-Standards of Performance for Electric Utility Steam Generating Units.

9. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate. This rule incorporates, by reference, 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP). Since the emission of HAPs from the YELP plant is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the YELP facility is not subject to the provisions of 40 CFR Part 61.

10. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as applicable. This rule incorporates, by reference, 40 CFR Part 63, NESHAP for Source Categories. Since the emission of HAPs from the YELP facility is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the facility is not subject to the major source provisions of 40 CFR Part 63.

a. 40 CFR 63, Subpart A – General Provisions apply to all equipment or facilities subject to a NESHAP Subpart as listed below:

b. 40 CFR 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) and also establishes requirements to demonstrate initial and continuous compliance with the emission limitations. YELP is an existing oil-fired electric utility steam generating unit and must be in compliance with this subpart no later than April 16, 2015.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. YELP must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. YELP submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the potential to emit (PTE) greater than 25 tons per year of any pollutant. YELP has a PTE greater than 25 tons per year of NO_x, CO, SO_2, and PM; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. YELP submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. YELP submitted an affidavit of publication of public notice for the May 27, 2012 issue of the Billings Gazette, a newspaper of general circulation in the Town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving YELP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

12. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

13. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules

adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

14. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

15. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

16. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, Montana Code Annotated (MCA).

17. ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units. This rule identifies mercury emission limitation requirements, mercury control strategy requirements, and application requirements for mercury-emitting generating units.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

This facility is a major stationary source. This AA request will not cause a change in emission and, therefore, does not require a New Source Review (NSR) analysis.

H. ARM 17.8, Subchapter 10 – Preconstruction Permit Requirements for Major Stationary Sources of Modifications Located Within Attainment or Unclassified Areas, including, but not limited to:

ARM 17.8.1004 When Air Quality Preconstruction Permit Required. This current permit action does not constitute a major modification. Therefore, the requirements of this subchapter do not apply.

I. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one hazardous air pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2650-08 for YELP, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for NO_x, CO, SO_2, and PM.

   b. The facility's PTE is less than 10 tons/year for any one HAP and less than 25 tons/year for all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject current NSPS (40 CFR 60, Subpart Da).

   e. This facility is not subject to any current NESHAP standards.

   f. This source is not a Title IV affected source.

   g. This source is not a solid waste combustion unit.

   h. This source is an EPA designated Title V source.

   Based on these facts, the Department determined that YELP is subject to the Title V operating permit program. Operating Permit #OP2650-03 was issued to YELP final and effective on November 30, 2019.

III. BACT Determination

A BACT determination is required for each new or modified source. YELP shall install on the new or modified source the maximum air pollution control capability which is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was not required for the current permit action because the current permit action is considered an administrative permit action.

IV. Emission Inventory

Calculation of annual average BTU/hr value for the boilers combined:

Lbs of coke per hour = 58,111

Lbs of coker gas per hour = 110,000

58,100 lb/hr * 14,400 BTU/lb + 110,000 lb/hr * 673.4 BTU/lb = 911 x 10^6 BTU/hr

The maximum coke feed rate is not expected to exceed 173,000 lbs/hr. The feed rate of coker gas is expected to be below the 110,000 lbs/hr identified in the above equation and will be dependent on Exxon's process. When cat slurry oil is combusted in the boiler, the amount of coke feed will be reduced.

The allowable emissions from the facility are identified in the permit. The permit limits the hourly emissions and the annual emissions from the main stack. In addition, permit #2650-05 limited the annual emissions from the coke unloading crushing/processing plant and the coke barn. Further, the permit included a grain loading limit for all baghouses at the facility.

Emission Inventory (MAQP #2650-05): Off-Site Petroleum Coke Unloading, Crushing, Processing, Storage, and Handling.

	Tons/yr					
Source	TSP	PM-10	NO_x	VOC	CO	SO_x
Crushing/Processing plant w/ Baghouse	5.26	5.26	0	0	0	0
Coke Barn Storage and Handling	16.86	8.43	0	0	0	0
Haul Roads	2.74	1.23	0	0	0	0
Total	24.86	14.92	0	0	0	0

Emission Inventory (MAQP #2650-07):

	Tons/yr					
Source	TSP	PM-10	NO_x	VOC	CO	SO_x
Crushing/Processing plant w/ Baghouse	4.07	4.07	0	0	0	0
Coke Barn Storage and Handling	14.12	7.06	0	0	0	0
Off-Site Coke Pile Forming (Exxon Pile)	3.50	1.75	0	0	0	0
Haul Roads	2.74	1.23	0	0	0	0
Total	24.43	14.11	0	0	0	0

- The department considers dumping of off-site coke at the existing Exxon coke pile to be part of the same off-site coke processing/handling activities permitted under permit action #2650-05.

  Potential total particulate matter (PM) emissions resulting from the dumping of off-site coke (35,000 tons) at the Exxon pile are 3.5 tons/yr. Because these potential emissions were not accounted for in permitting action #2650-05, which established limits keeping YELP out of NSR/PSD review for coke (off-site) processing activities at the plant, and because YELP wishes to stay out of NSR/PSD review for the current permit action

#2650-07, combined production at the crushing facilities, while off-site coke is being dumped and stored at the Exxon pile, must be restricted to a level that would result in a reduction of 3.5 tons/yr potential PM emissions to allow for the increased potential PM emissions resulting from off-site coke dumping at the Exxon pile. This limit of 202,000 tons during any rolling 12 month time period, established in Section II.H.2.b of permit #2650-07, applies when off-site coke is being dumped/stored at the Exxon Refinery coke storage area, otherwise, the original production limit of 240,900 tons during any rolling 12 month time period, established in permit #2650-05, applies.

- A complete emission inventory for the YELP facility is on file with the department.

Emission Inventory (MAQP#2650-08 modification)

Source	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NOx (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)
45, 000 tons Reserve Coke Stockpile	12.11	4.66	1.46				
2,000 tons Limestone Stockpile	0.686	0.229	0.229[1]	0.0836	0.018	0.00678	0.00553
Coke Load-out Silo	2.68	1.27	0.19				
Remove: Cat Slurry Oil Tank						-0.01	
TOTAL FOR PROJECT	**15.476**	**6.159**	**1.879**	**0.0836**	**0.018**	**-0.01**	**0.00553**

Notes:
1. Assume $PM_{2.5} = PM_{10}$ for Limestone stockpile

Reserve Coke Pile (45,000 tons)

Emissions Summary (Reserve Coke Pile)							
	NOX (tpy)	CO (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	VOC (tpy)
Wind Erosion[a]	---	---	---	1.09	1.09	1.09	---
Vehicle Traffic	---	---	---	10.33	3.24	0.32	---
Material Handling	---	---	---	0.69	0.33	0.049	---
Total:	---	---	---	**12.11**	**4.66**	**1.46**	---

a. Wind erosion estimates calculated using the more conservative method of AP-42 Chapter 11.9

Wind Erosion Emissions: AP-42 Western Surface Coal Mining Method, Chapter 11.9		
Emission Factor		
TSP (Table 11.9-4)	0.38	tons/acre/year
PM-10 Table 11.9-4, Conservative Estimate using same factor as TSP	0.38	tons/acre/year
PM-2.5 Table 11.9-4, Conservative Estimate using same factor as TSP	0.38	tons/acre/year

Size of Stockpiles: 1.25 acres (17,000 ton area) + 1.62 acres (28,000 ton areas) =	2.87 acres	
Calculation: 0.38 tons/acre/year * 2.87 acres = 1.09 tons/year		
Emissions From Wind, Using Conservative Western Surface Coal Mining Method		
TSP:	1.09	tons/year
PM-10	1.09	tons/year
PM-2.5	1.09	tons/year

Fugitive Emissions - Unpaved Surface Material Transport Emissions	
Equation 1(a), AP-42 13.2.2	
Vehicle Miles Traveled Calculations	
Total Tons to Be Temporarily Stored in Pile (tons):	**45,000**
Density factor of Petroleum Coke (lb/ft^3):[a]	55
Conversion Factor: (ft^3/yd^3)	27
Volume of Stored Coke (ft^3):	1636364
Volume of Stored Coke (yd^3):	60606

Front End Loader - Unpaved Roads	
Hauling/Pushing Capacity (yd^3):	5.5
Total Trips to Push Coke Into Stockpile:	11019
Estimated Round Trip Average Distance to Push Coke Into Pile (ft,)[b]	520
Total Miles Traveled to Push Coke in Pile (VMT):	1085
Estimated Round Trip Avg Distance Traveled by Front End Loader to Loading Facility(ft)[b]	670
Total Trips to Push Coke Into Stockpile:	11019
Total Miles Travelled to Refill Trucks (VMT):	1398
Total Vehicle Miles Traveled by Loader:	2484

Unpaved Roads Emission Calculations
$E = k*(s/12)^a*(W/3)^{b*}((365-p)/365))$

Loader Emission Estimates		
PM		
Where:		
Particulate Emission Factor (k)	4.9	
a (empirical constant)	0.7	
b (empirical constant)	0.45	
s: Road Surface Silt Loading (%, median of values from Table 13.2.2-3)	13.5	
p: Total number of wet days in year (>.01 inches of precipitation):	120	
Average Weight of Vehicle (tons, Komatsu 380 Wheel Loader used as example)[c]	19.63	
E (lb/VMT):	8.32	lb/VMT
PM/TSP (lbs)	20656.28	lb/yr
PM/TSP (tons)	**10.33**	**tons/yr**
PM-10		
Where:		
Particulate Emission Factor (k)	1.5	

a (empirical constant)	0.9	
b (empirical constant)	0.45	
s: Road Surface Silt Loading (%, median of values from Table 13.2.2-3)	13.5	
p: Total number of wet days in year (>.01 inches of precipitation):	120	
Average Weight of Vehicle (tons, Komatsu 380 Wheel Loader used as example)[c]	19.63	
E (lb/VMT):	**2.61**	lb/VMT
	6474.07	
PM-10 (lbs)	5	lb/yr
PM-10 (tons)	**3.24**	**tons/yr**
PM-2.5		
Where:		
Particulate Emission Factor (k)	0.15	
a (empirical constant)	0.9	
b (empirical constant)	0.45	
s: Road Surface Silt Loading (%, median of values from Table 13.2.2-3)	13.5	
p: Total number of wet days in year (>.01 inches of precipitation):	120	
Average Weight of Vehicle (tons, Komatsu 380 Wheel Loader used as example)[c]	19.63	
E (lb/VMT):	**0.26**	lb/VMT
PM-2.5 (lbs)	647.41	lb/yr
PM-2.5 (tons)	**0.32**	**tons/yr**

a. Source: http://www.powderandbulk.com/resources/bulk_density/material_bulk_density_chart_p.htm
b. Estimated using Google Earth.
c. Source: http://www.forconstructionpros.com/product/10079208/komatsu-america-corp-wa380-6-wheel-loader

Fugitive Emissions - Petroleum Coke Handling

E = k (0.0032) ((U/5)^1.3)/((M/2)^1.4) AP-42, 13.2.4.3 (1/95)
E = emission factor
k = particle size multiplier (dimensionless)
U = mean wind speed, meters per second (m/s) (miles per hour [mph])
M = material moisture content (%)

Handling Steps
1. Use front end loader to transfer petroleum coke from barn to yard.
2. Use front end loader to shape and compact the pile.
3. Use front end loader to remove coke from pile.
4. Use front end loader to dump coke back into coke unloading/crushing/processing system. Emissions controlled by baghouse.

PM-2.5, Material Transfers for Coke (not enclosed)		
k=	0.053	

U=	11.03	average of NWS 2011 Data
M=	1.46	Based on lab analysis
E=0.053(0.0032)((11.03/5)^1.3)/((1.46/2)^1.4) =	7.37E-04	lb/ton of Material Transferred
Total Tons Stockpiled:	45,000	tons
Times Stockpile will be Handled/Transferred:	3	Loading back into coke barn controlled by existing baghouse.
Total Tons Handled (Stockpile Outside, Return to Coke Barn):	135,000	
Total lbs PM-2.5 from Handling:	9.95E+01	lb/yr
Total tons PM-2.5 from Handling:	4.98E-02	TPY
PM-10, Material Transfers for Coke (not enclosed)		
k=	0.35	
U=	11.03	average of NWS 2011 Data
M=	1.46	Based on lab analysis
E=0.35(0.0032)((11.03/5)^1.3)/((1.46/2)^1.4) =	4.87E-03	lb/ton of Material Transferred
Total Tons Transferred:	45,000	
Times Stockpile will be Handled/Transferred:	3	Loading back into coke barn controlled by existing baghouse.
Total Tons Handled (Stockpile Outside, Return to Coke Barn):	135,000	
Total lbs PM-10 from Handling:	6.57E+02	lb/yr
Total tons PM-10 from Handling:	3.29E-01	TPY
PM, Material Transfers for Coke (not enclosed)		
k=	0.74	
U=	11.03	average of NWS 2011 Data
M=	1.46	Based on lab analysis
E=0.74(0.0032)((11.03/5)^1.3)/((1.46/2)^1.4) =	1.03E-02	lb/ton of Material Transferred
Total Tons Transferred:	45,000	
Times Stockpile will be Handled/Transferred:	3	Loading back into coke barn controlled by existing baghouse.
Total Tons Handled (Stockpile Outside, Return to Coke Barn):	135,000	
Total lbs PM-10 from Handling:	1.39E+03	lb/yr
Total tons PM from Handling:	6.95E-01	TPY

Limestone Stockpile (2,000 tons)

Emissions Summary (Limestone stockpile)							
	NOX (tpy)	CO (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	VOC (tpy)
Wind Erosion	---	---	---	0.142	0.0719		---
Vehicle Traffic	---	---	---	0.518	0.146		---
Material Handling	---	---	---	0.0263	0.0124		---
Front end loader engine	0.0836	0.018	0.00553	---	5.93E-06		0.00678
Total:	**0.0836**	**0.018**	**0.00553**	**0.686**	**0.229**		**0.00678**

Note: Detailed emissions calculations for Limestone stockpile on file in the Department. See de minimis request dated October 25, 2005

Coke Load-out Silo

Maximum Process Rate = 146,000 ton/yr (Maximum plant process rate)
Number of Emitting Points = 2 points

Filterable PM Emissions:
Predictive equation for emission factor provided per AP 42, Section 13.2.4.3, 11/06.
Emission Factor = k (0.0032) * (U/5)^1.3 * (M / 2)^-1.4 = 0.01834 lb/ton
Where: k = particle size multiplier = 0.74 (Value for PM < 30 microns)
U = mean wind speed = 11.2 mph (Supplied by Bison/YELP, Annual Average from NCDC)
M = material moisture content = 0.98% (Supplied by Bison/YELP, ExxonMobil coke moisture)
Calculation: (146,000 ton/yr) * (0.01834 lb/ton) * (ton/2000 lb) * (2 piles) = 2.68 ton/yr

Filterable PM_{10} Emissions:
Predictive equation for emission factor provided per AP 42, Section 13.2.4.3, 11/06.
Emission Factor = k (0.0032) * (U/5)^1.3 * (M / 2)^-1.4 = 0.00867 lb/ton
Where: k = particle size multiplier = 0.35 (Value for PM < 10 microns)
U = mean wind speed = 11.2 mph (Supplied by Bison/YELP, Annual Average from NCDC)
M = material moisture content = 0.98% (Supplied by Bison/YELP, ExxonMobil coke moisture)
Calculation: (146,000 ton/yr) * (0.00867 lb/ton) * (ton/2000 lb) * (2 piles) = 1.27 ton/yr

Filterable $PM_{2.5}$ Emissions:
Predictive equation for emission factor provided per AP 42, Section 13.2.4.3, 11/06.
Emission Factor = k (0.0032) * (U/5)^1.3 * (M / 2)^-1.4 = 0.00131 lb/ton
Where: k = particle size multiplier = 0.053 (Value for PM < 2.5 microns)
U = mean wind speed = 11.2 mph (Supplied by Bison/YELP, Annual Average from NCDC)
M = material moisture content = 0.98% (Supplied by Bison/YELP, ExxonMobil coke moisture)
Calculation: (146,000 ton/yr) * (0.00131 lb/ton) * (ton/2000 lb) * (2 piles) = 0.19 ton/yr

Condensable PM:
Assumed to be zero (0) because this is a non-combustion process.

Abbreviations:
ton/yr = tons per year
PM = particulate matter
lb/ton = pounds per ton
mph = miles per hour
NCDC = National Climatic Data Center
lb = pound
PM_{10} = PM with an aerodynamic diameter $\leq$ 10 microns
$PM_{2.5}$ = PM with an aerodynamic diameter $\leq$ 2.5 microns
CO = carbon monoxide
HAPs = hazardous air pollutants
hp = horsepower
N/A = not applicable
ND = no data available
NO_X = oxides of nitrogen
SO_2 = sulfur dioxide
TPH = tons per hour
TPY = tons per year
VOC = volatile organic compounds
yr = year

V. Existing Air Quality

The YELP plant is located in the NE¼ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana. The air quality classification for the immediate area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for all pollutants. The Laurel SO_2 nonattainment area is about 31.9 kilometers (19.8 miles) southwest from the center of the main operating facility. The Billings is in attainment with the SO2 standards. Billings is operating under a maintenance plan whose boundary is less than 1 mile south southwest of the facility.

VI. Ambient Air Impact Analysis

The Department determined that there will be no impact from this administrative permitting action as no new emissions will result with implementation of this permitting action. The Department believes the permitting action will not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following

		questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

This permitting action will not result in an increase of emissions from the facility and is considered an administrative action; therefore, an environmental assessment is not required.

Analysis prepared by: J Ackerlund
Date: August 19, 2020