AIR QUALITY PROGRAM
Environmental Programs Division
Southern Ute Indian Tribe
PO Box 737 MS#84
Ignacio, CO 81137
Phone 970-563-4705
http://www.southernute-nsn.gov/environmental-programs-air-quality

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

February 21, 2014

Julie Best
BP America Production Company
Environmental Advisor
380A Airport Road
Durango, Colorado 81303

Re: Final Part 70 Operating Permit
Title V Permit #V-SUIT-0001-2014.00
BP America Production Company
Treating Site #1 Central Delivery Point

Dear Ms. Best:

The Southern Ute Indian Tribe Air Quality Program (Tribe) has completed its review of BP America Production Company's (BP) request to obtain a Title V Permit to Operate pursuant to the Title V Operating Permit Program at 40 CFR Part 70, for the Treating Site #1 Central Delivery Point.

Based on the information submitted in the company's application and the comments received during the public comment period, the Tribe hereby issues the enclosed Title V Permit to Operate. The final permit will become effective on April 2, 2014.

A 30-day public comment period was held from September 9, 2013 to October 9, 2013. The Tribe received comments from Rebecca Robert, Air Specialist for BP on October 4, 2013. No other comments were received from the public, affected states, or tribes. The Tribe reviewed the comments received and provided responses in Enclosure 1, "Response to Comments Document." These comments resulted in administrative amendments and clarifications to the requirements of the permit for this facility.

Following the 30-day public comment period, the Tribe noted the need to make administrative revisions to the following sections:

1. Section – III.C.1. and 2. Alternative Operating Scenarios-Engine Replacement
    - Text revised to clarify the requirements.
2. Section – IV.P.1. Permit Expiration and Renewal

- Text revised to better align with the RAC.

These revisions are administrative in nature and do not alter any of the enforceable requirements of the permit.

The Tribe also noted that the Compliance Assurance Monitoring (CAM) Plan Monitoring Approach was lacking necessary data collection procedures for Indicator #1 and that additional language was needed to clarify and strengthen the monitoring frequency requirement of Indicator #3. This additional language was agreed upon in a correspondence with BP on December 5, 2013, and resulted in changes to the following sections:

1. Section – V.B.B Compliance Assurance Monitoring (CAM) Plan Monitoring Approach
   - Data collection procedures have been added to the Data Collection Procedures requirements of Indicator #1 (Temperature of exhaust gas into the catalyst).
   - Additional language has been added to the Monitoring Frequency requirements of Indicator #3 (NOx and CO measurement).

Additionally, the Tribe has made the following revisions to the permit based on suggestions from EPA Region 8 during the 45-day administrative review period, which was held from December 6, 2013 to January 20, 2014:

1. Section – II.B.2. 40 CFR Part 63, Subpart ZZZZ Work, Operation and Management Practices.
   - Revised the text to clarify the requirements of permit condition II.B.2.6.

Pursuant to RAC § 2-109(8), within 60 days after the final permit has been issued, the applicant, any person who participated in the public comment process and is aggrieved by the action, and any other person who could obtain judicial review of that action under applicable law, may appeal to the Environmental Commission in accordance with the Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code (RAC) and the Commission's Procedural Rules. Additionally, the regulations at RAC § 2-109(7) specify that any person may petition the EPA Administrator within 60 days after the expiration of the Administrator's 45-day review period to make an objection that the permit would not be in compliance with applicable requirements. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objections arose after such period.

If you have any questions concerning the enclosed permit, please contact Danny Powers of my staff at 970-563-4705 ext. 2265.

Sincerely,

Brenda Jarrell

Brenda Jarrell
Air Quality Program Manager
Southern Ute Indian Tribe

Cc: Matthew Langenfeld - Tribal Air Coordinator - US EPA Region 8

Enclosure –

Response to Comments Document

Comments from BP America Production Company received on Draft Title V Permit to Operate

BP appreciates the opportunity to provide the following comments on the proposed Title V operating permit number V-SUIT-0001-2014.00 and associated Statement of Basis for the Treating Site # 1 Central Delivery Point. Please note that strikethrough comments represent requested deletions and underline italicized comments represent requested additions to the permit and Statement of Basis language.

1. Permit, Universal Comments

(A) On pages 3-9 BP requests to align the outline and numbering format for sections II.B and II.C with the remainder of the permit.

Tribe's Response: The requested correction has been made.

2. Permit, Page 2, Table 1

(A) BP requests to update the TS1-3 description as follows: "Serial No. ~~401074~~ *399858* Installed: ~~1992~~ *2012*." The TS1-3 engine was replaced in October 2012. BP provided SUIT a copy of the Part 71 Off Permit Change notification for this replacement on October 12, 2012. Please note that Table 1 in the Statement of Basis has the correct information.

Tribe's Response: The requested correction has been made.

3. Permit, Page 4, Condition II.B.2.

(A) On page 4, BP requests to add the following language to Condition II.B.2.a. to identify that the operating limitations and other requirements mentioned in the condition are specifically 40 CFR Part 63 Subpart ZZZZ requirements:

> "For emission units TS1-1, TS1-2, TS1-3, and TS1-4, the permittee shall comply with the *applicable 40 CFR Part 63, Subpart ZZZZ* operating limitations, and other requirements at all times."

Tribe's Response: The requested clarification has been made.

(B) On page 4, BP requests to rearrange Conditions II.B.2.b - d. and add the following language to clarify that the oil analysis program option is an alternative to the hourly-based oil change requirement:

> "b. For emissions units TS1-1 and TS1-2, the permittee shall change the oil and inspect and replace as necessary all spark plugs, hoses, and belts every 2,160 hours of operation or annually, whichever comes first~~; or~~ *The permittee may utilize the oil analysis*

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program option, as specified in Condition II.B.2.d. of this section, to extend the specified oil change requirement.

c. For emissions units TS1-3 and TS1-4, the permittee shall change the oil and filter and inspect and replace as necessary all spark plugs, hoses, and belts every 1,400 hours of operation or annually, whichever comes first. *The permittee may utilize the oil analysis program, as specified in Condition II.B.2.d. of this section, to extend the specified oil change requirement.*

d. *As mentioned in Conditions II.B.2.b. and c. of this section,* ~~F~~ *f*or emissions units TS1-1, TS1-2, TS1-3, and TS1-4, the permittee shall have the option of utilizing an oil analysis program in order to extend the specified oil change requirements in Tables 2c and 2d to *40 CFR Part 63,* ~~this~~ Subpart *ZZZZ.*

Tribe's Response: The requested clarifications have been made.

C. On page 5, BP requests to delete condition II.B.2.h since TS1-1, TS1-2, TS1-3, and TS1-4 do not have applicable 40 CFR part 63, Subpart ZZZZ emission limits.

Tribe's Response: The requested deletion has not been made. The regulations in Table 2d of 40 CFR Part 63, Subpart ZZZZ, specify that during times of startup all engine categories listed in the table must adhere to the requirements captured in permit condition II.B.2.,regardless of whether or not the engine category has emission limitations under Subpart ZZZZ.

4. Permit, Page 5, Condition II.B.3

A. In Condition II.B.3.a, BP requests to delete ~~"emission limitation"~~ from the condition. TS1-1, TS1-2, TS1-3, and TS1-4 do not have 40 CFR Part 63, Subpart ZZZZ emissions limitations.

B. In Condition II.B.3.b, BP requests to update this condition as follows:

"The permittee must report each instance in w~~hich an emi~~ssion or operating limit was not met. These instances are deviati~~ons from the e~~mission and operating limitations and must be reported according to the reporting requirements of 63.6650*(f) and in the semiannual monitoring report required under the Facility-Wide Reporting Requirements section of this permit"*

TS1-1, TS1-2, TS1-3, and TS1-4 do not have 40 CFR Part 63, Subpart ZZZZ emission limitations. Additionally, the only reporting requirement applicable to TS1-1, TS1-2, TS1-3, and TS1-4 under 40 CFR 63.6650 is in section (f), which also references the required Part 70 semiannual monitoring report.

Tribe's Response: The requested clarifications have been made.

Since Condition II.B.3.b is a reporting requirement, this condition may also be more appropriately cited in Condition II.B.6. of the permit, rather than in Condition II.B.3.

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Tribe's Response: BP's suggestion to move permit Condition II.B.3.b has not been made. The Tribe would prefer to keep this requirement in the Continuous Compliance Section.

5. Permit, Page 6, Condition II.B.5

A. On page 6, BP requests to revise condition II.B.5.c. as follows:

> "The permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that the stationary RICE are operated and maintained according to <u>*the manufacturers*</u> or the permittee's own maintenance plan."

BP also requests to add <u>*40 CFR 63.6655(d)*</u> and <u>*Table 6*</u> as citations for permit condition II.B.5.c, as 40 CFR Part 63, Subpart ZZZZ, Table 6 allows the use of either the manufacturer's maintenance plan or our own maintenance plan for all affected sources at the site. This option to use either the manufacturer's maintenance plan or our own maintenance plan is also established in Conditions II.B.2.e and f of the proposed permit.

Tribe's Response: The suggested clarifications have been made.

6. Permit, Page 6, Condition II.B.6

A. BP requests to delete Condition II.B.6.a, as the requirement to submit a semiannual monitoring report is not specifically a 40 CFR Part 63, Subpart ZZZZ requirement. The semiannual monitoring report requirement is already captured in the Facility-Wide Reporting Requirements section of the permit.

Additionally, the 40 CFR Part 63 reporting requirements are already captured in Conditions II.B.3.b and II.B.6.b. of the proposed permit.

As mentioned above in item 4, Since Condition II.B.3.b. is a reporting requirement, this condition may also be more appropriately cited in Condition II.B.6. of the permit rather than in Condition II.B.3.

Tribe's Response: The suggested clarifications have been made.

7. Permit, Pages 7-8, Condition II.C

A. In Condition II.C.a, BP requests to correct the PSD permitted hp for each of the engines listed as follows:

> "Unit TS1-1- ~~1,198~~ <u>*1,215*</u> ~~site rated~~ bhp…"
> "Unit TS1-2- 1,~~198~~ <u>*1,215*</u> ~~site rated~~ bhp…"
> "Unit TS1-3- ~~57~~ <u>*68*</u> ~~site rated~~ bhp…"
> "Unit TS1-4- ~~97~~ <u>*105*</u> ~~site rated~~ bhp…"

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BP also requests to delete "…~~constructed or reconstructed prior to June 12, 2006~~…" for each of the engines listed in this condition as this information is not relevant for the PSD section of permit.

Tribe's Response: The suggested corrections have been made.

B. BP requests to add the following Maintenance and Operation condition to the Title V permit from the PSD permit:

"*<u>At all times, including periods of startup (except for replacement/overhauled engines), shut-down, and equipment malfunction, the facility, to the extent practical, shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA, which may include, but not be limited to monitoring results, review of operating and maintenance procedures, manufacturer's specifications, industry practices, or inspection of the facility."</u>*

Tribe's Response: This Maintenance and Operation condition has been added, as verbatim, from the PSD permit for Treating Site #1 CDP.

C. On page 8, in Condition II.C.4.c, BP requests to update this condition to align with the PSD permit language:

> "c. The permittee shall provide the ~~Tribe and~~ EPA with at least 30 (thirty) calendar days prior notice (in writing) of any emissions test required by this permit, in order to give the ~~Tribe and~~ EPA the opportunity to observe the test; unless a shorter timeframe is agreed upon by the permittee, ~~the Tribe~~, and EPA."

Tribe's Response: BP's request to update this condition to align with the PSD permit language has not been granted. According to RAC 2-110(7), the permit shall require reporting sufficient to assure compliance with the terms and conditions of the permit and all applicable requirements, including incorporation of all applicable reporting requirements. Because PSD permitting terms and conditions are defined by RAC 1-103(11)(c) as applicable requirements and RAC 2-110(1)(b) requires that all applicable requirements are included in the Part 70 permit, they have been incorporated into this Part 70 operating permit; and, The Tribe feels that receiving notifications of the emission tests required by the PSD permit will help the Tribe ensure compliance with the applicable requirements of this permit. The citation to RAC 2-110(7) has been added to permit condition II.C.4. for clarity.

The language granting the Tribe to authority to approve a shorter timeframe for notifications has been removed.

D. On page 8, in Condition II.C.5.a, BP requests to delete "~~,and.~~.." after "compliance tests."

Tribe's Response: The requested correction has been made.

E. On page 9, in Condition II.C.5.b, BP requests to update this condition to align with the PSD permit language:

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"b….This data must be available at the permittee's nearest regularly manned facility for inspection by ~~the Tribe~~ and EPA and must be submitted to ~~the Tribe~~ and EPA upon request."

Tribe's Response: BP's request to update this condition to align with the PSD permit language has not been granted. According to RAC 2-110(6), the permit shall require recordkeeping sufficient to assure and verify compliance with the terms and conditions of the permit, including all applicable recordkeeping requirements. Because PSD permitting terms and conditions are defined by RAC 1-103(11)(c) as applicable requirements and RAC 2-110(1)(b) requires that all applicable requirements are included in the Part 70 permit, the PSD recordkeeping requirements have been incorporated into this Part 70 operating permit; and, the Tribe feels that the ability to inspect or request PSD records is necessary to ensure compliance with the terms, conditions, and applicable recordkeeping requirements of this permit. The citation to RAC 2-110(6) has been added to permit condition II.C.5.for clarity.

F. On page 9, in Condition II.C.6.a, BP requests to update this condition to align with the PSD permit language:

"a. The permittee shall submit a written report of any initial compliance test results for replacement/overhauled engines installed at the facility and for any engine compliance tests required by the ~~Tribe and~~ EPA

Tribe's Response: The requested change has been made.

G. On page 9, in condition II.C.6.b, BP requests to delete "…~~.and the parametric monitoring results and maintenance activities.~~…" in this condition since the PSD Monitoring Requirements section no longer includes these activities.

Tribe's Response: This language has been removed from the PSD Monitoring Requirements section of the permit and added to the Periodic Monitoring Requirements section of the permit.

8. Permit, Pages 12-16, Section III. Facility-Wide Requirements

A. On page 13, in condition III.A.3, BP requests to change the language as follows:

" The permittee is the owner or operator of glycol dehydration units (Units TS1-7b and TS1-10b) that ~~is~~ *are* exempt from the control requirements under 40 CFR 63.764. The permittee shall retain each determination used to demonstrate that actual annual average flowrate of natural gas to each glycol dehydrator is less than 85,000 scm/day (3,000,000 scf/day) or the actual average benzene emissions *from each dehydrator* are below 1 tpy."

Tribe's Response: The requested correction has been made.

B. On Page 13, in Condition III.B.1., BP requests to change the verbiage of this condition for the semi-annual reporting periods to the following:

"The permittee shall submit to the Tribe all reports of any required monitoring under this permit semiannually. The report shall be submitted semi-annually by April 1st and

October 1st of each year. The report due on April 1st shall cover the July 1-December 31 reporting period of the previous calendar year. The report due on October 1st shall cover the January 1-June 30 reporting period of the ~~previous~~ *current* calendar year."

Tribe's Response: The requested correction has been made.

C. On page 14, in Condition III.B.3.b, BP requests the Tribe to provide the appropriate email, telephone, and facsimile contact information for prompt deviation reporting. This information is not included in the proposed permit.

Tribe's Response: The requested change has not been made. The appropriate contact information for prompt deviation reporting will be kept current on the Tribe's Part 70 Program Website.

D. On page 15, in condition III.C.1.d, BP requests to correct the number format to add "(vi)" before "Requirements established in any promulgated Federal Implementation Plan that may apply to engines located on the Southern Ute Indian Reservation."

Tribe's Response: The requested correction has been made.

9. Permit, Pages 16-26, Section IV. Part 70 Administrative Requirements

A. On page 16, in Condition IV.A.3., BP requests to include the option to send fee payments via common carrier (such as UPS or Fed Ex) and requests the following language be included to align with the RAC language:

> "Fee payments shall be remitted in the form or a money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the Southern Ute Indian Tribe and sent or delivered to the Tribe *by the United States Postal Service* c/o ~~Air Quality Program~~ *Environmental Programs Division, Part 70 Program*, P.O. Box 737 MS #84 Ignacio, Colorado 81137; *or by common carrier (such as UPS or FedEx) c/o Environmental Programs Division, Part 70 Program, 398 Ouray Drive, Ignacio Colorado 81137.*

Tribe's Response: The language has been changed to align with the most current RAC language.

B. On page 18, in Condition IV.C.1 BP requests to revise the first sentence in this condition to align with the RAC regulatory language:

> "The permittee shall furnish to the Tribe, within ~~a~~ the period specified by the Tribe, any information that the Tribe request in writing to determine whether cause exists for *reopening and revising* ~~modifying,~~ revoking, and reissuing, or terminating the permit, or to determine compliance with the permit."

Tribe's Response: The language has been changed to align with the most current RAC language.

C. On page 21, in Condition IV.H.2.b. and c., BP requests to change the verbiage to align with the RAC regulatory language:

> "*By United States Postal Service:* *or by Common Carrier:*

Cc: Matthew Langenfeld - Tribal Air Coordinator - US EPA Region 8

Part 70 Program Environmental Programs Division Air Quality Program P.O. Box 737 MS #84 Ignacio, Colorado 81137	*Part 70 Program* *Environmental Programs Division* *Air Quality Program* *398 Ouray Drive* *Ignacio, Colorado 81137*

Tribe's Response: The option to send submissions via common carrier and to the Tribe's Current addresses have been added to align with the most current RAC language.

D. On page 21, in Condition IV.H.2.b. and c., BP requests to change the verbiage to align with the RAC regulatory language as follows:

> "2. An application requesting the use of minor permit revision procedures shall meet the requirements of RAC 2-106(4) and shall include the following:
>
> > (b) If changes are requested to the permit language, ~~T~~*t*he permittee's suggested draft permit *changes* ~~language~~;
> > (c) Certification by a responsible official, consistent with RAC 2-105, that the proposed ~~modification~~ *revision* meets the criteria for use of minor permit ~~modification~~ *revision* procedures and a request that such procedures be used; and…"

Tribe's Response: The language has been changed to align with the most current RAC language.

10. Permit, Pages 28-30, Section V.B. Compliance Assurance Monitoring (CAM) Plan

A. As mentioned in the updated CAM Plan submitted to the Tribe, to satisfy the proposed CAM monitoring requirements, significant upgrades are required at the facility. Accordingly, BP requests six months from the effective date of the initial part 70 operating permit to perform the needed upgrades.

Tribe's Response: Per 40 CFR 64.4(e), if the monitoring submitted requires the installation, testing, or other necessary activities prior to monitoring, the permitting agency (The Tribe) may grant the owner or operator (permittee) 180 days from permit approval (issuance) to meet the requirements of an agency approved CAM plan. Therefore, the Tribe has added language to permit condition II.D.2 granting BP 180 days from the issuance date of this Part 70 operating permit to be incompliance with the CAM requirements. To account for the interim period between permit issuance and BP's compliance with the CAM plan, the periodic monitoring from the Part 71 permit has been extended into this permit. This periodic monitoring will no longer apply upon BP's compliance with the CAM plan.

B. In Section V.B.A.2, BP requests to update the PSD Permit Number to #PSD-SU-0006-95.~~00~~ *01* to reflect the most recent PSD permit revision.

Tribe's Response: The requested PSD permit number has been verified and added to the permit

C. In Section V.B.A.2, BP requests to correct the Potential pre-control device CO emissions as follows: "CAM Emission Limits: NOx: 2.7 lbs/hr; ~~11.27~~ *11.7* TPY"

Cc: Matthew Langenfeld - Tribal Air Coordinator - US EPA Region 8

Tribe's Response: The requested correction has been made.

D. In Section V.B.A.3, BP requests to correct the Potential pre-control device CO emissions as follows: "Potential pre-control device emissions: CO: 75.0 lbs/hr; ~~23.5~~ *328.5* TPY"

Tribe's Response: The requested correction has been made.

E. In the table in Section V.B., on page 29, under Indicator NO. 1 for QA/QC Practices and Criteria, BP requests to delete "…at least yearly" from the temperature sensing device calibration requirement. BP is requesting to calibrate these devices per the manufacturer's specifications.

Tribe's Response: The requested change has been made. The calibration of monitoring devices according to the manufacturer's specifications is an acceptable CAM QA/OC practice criteria, per 40 CFR 64.3(b)(2)

F. In the table in Section V.B.B, on page 29, under Indicator No. 3 for QA/QC Practices and Criteria, BP requests to change the verbiage as follows: "As stated in approved portable monitoring protocols or *Reference Methods."*

Tribe's Response: The option to use the QA/AC practices outlined in EPA Reference Methods has been added, as EPA References Methods are a measurement approach already listed in Indicator No.3 of the approved CAM plan.

G. On page 30, under Justification Section II, BP requests to delete "Daily…" from the last sentence in the first paragraph: "~~Daily m~~*M*onitoring of inlet gas temperatures…"

Tribe's Response: This requested correction has been made. In the approved CAM plan inlet gas temperatures are monitored continuously.

H. On page 30, under Justification Section II, BP requests to delete the last sentence in the second paragraph since this sentence is referring to the rationale for selection of indicator ranges, rather than performance indicators.

"~~When a catalyst is replaced or cleaned, the reference pressure differential must be re-established using a pressure differential gauge after a Maintenance Test confirms compliance with the NOx and CO limits~~"

Tribe's Response: This sentence has been deleted from section II of the Justification, Rational for Selection Performance Indicators, and equivalent language, suggested by BP in public comment 10.I, has been added section II of the Justification, Rational for Selection of Indicator Ranges.

I. On page 30, under Justification Section III, BP requests to add the following language und Rationale for Selection of Indicator Ranges:

"*Benchmark values for catalyst inlet pressure drop over the catalyst bed will be established as the first readings following permit issuance. Benchmarks will be set similarly for newly installed catalysts. Within 60 days of installing a new catalyst, portable analyzer emissions monitoring will be performed to demonstrate compliance with emission limits."*

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BP also requests that the above language be footnoted under the Monitoring Approach table or specifically highlighted in a permit condition format.

Tribe's Response: BP's suggested language has been added to Justification Section III. The language has also been footnoted under the Monitoring Approach Table.

11. Statement of Basis, Section 1

A. In Section 1.e., under Facility Construction and Permitting History, BP requests the following corrections:

> "The EPA issued the initial Part 71 permit (#V-SU-0001-00.00, ~~on March 27, 2000~~ *in September1999.* The EPA issued a Part 71 renewal permit (#V-SU-0001-05.00) ~~on January 30, 2008~~ *in September 2007, which was amended in January 2008 (#V-SU-0001-0001-05.01)*. That permit will be replaced by this initial Part 70 permit, #V-SUIT-0001-~~2013~~*2014*.00."

Tribe's Response: The requested correction has been made.

B. BP requests to correct the potential-to-emit values listed in Table 3 to align with the PTE table submitted in their November 8, 2012 permit application amendment. Also, the changes for GHG (CO_2e) emissions are requested to represent tons per year (tpy) rather than metric tons per year (mtpy)

Tribe's Response: The potential to emit values have been updated as requested, according to BP's November 8, 2012 permit application amendment.

12. Statement of Basis, Section 2.

(A) In Table 4, under the applicability discussion for 40 CFR 60, Subpart JJJJ, BP requests to correct the manufacture dates for the following engines.

Unit	
TS1-3	~~5/18/1989~~ 8/16/1988
TS1-4	8/16/1988 9/16/1989

Tribe's Response: The requested corrections have been made. The Tribe was copied on a Part 71 permit Off-Permit Change/AOS Notification to EPA on October 12, 2013, in which Unit TS1-3 was exchanged, resulting in the need to update the manufacture date for this unit. The corrected date for TS1-4 aligns with the information provided in BP's initial Part 70 operating permit application.

(B) In Table 5, under the applicability discussion for 40 CFR Part 63, Subpart ZZZZ, BP requests to correct the site rated bhp for TS1-1 and TS1-2 to ~~"1,~~1194.

Tribe's Response: The requested correction has been made. These emissions units have a site-rated bhp of 1194 bhp.

Cc: Matthew Langenfeld - Tribal Air Coordinator - US EPA Region 8

(C) BP requests to correct the last paragraph in the applicability discussion for Compliance Assurance Monitoring (CAM) Rule as follows:

> "According to BP, Treating Site #1 Central Delivery Point is a major source of NOx, *and* CO, ~~and VOCs."~~

Tribe's Response: The requested correction has been made.

Cc: Matthew Langenfeld - Tribal Air Coordinator - US EPA Region 8

Air Pollution Control
Title V Permit to Operate
Statement of Basis for Permit No V-SUIT-0001-2014.00
February 21, 2014

BP America Production Company
Treating Site #1 Central Delivery Point
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

The Treating Site #1 Central Delivery Point, owned and operated by BP America Production Company (BP), is located within the exterior boundary of the Southern Ute Indian Reservation. The exact location is NW¼ SE¼ Section 13, T 32N, R8W, in La Plata County, at latitude North 37.015784 and longitude West -107.664496. The Mailing address is:

BP America Production Company
Treating Site #1 Central Delivery Point
380A Airport Road
Durango, CO 81303

b. Contacts

Facility Contact:
Julie Best
Environmental Advisor
BP America Production Company
380A Airport Road
Durango, CO 81303
970-375-7540

Responsible Official:
Stephen Collins
Onshore Site Manager –
San Juan North
BP America Production Company
380A Airport Road
Durango, CO 81303
970-247-6810

Alternate Responsible Official:
Jerry Austin
Area Operations Manager
BP America Production Company
501 Westlake Park Boulevard
Houston, TX 77079
281-366-2953

Alternate Responsible Official:
John Mummery
Deputy Onshore Site Manager –
San Juan North
BP America Production Company
380A Airport Road
Durango, CO 81303
970-749-4139

c. Description of Operations

Treating Site #1 Central Delivery Point is a central facility used to separate and dry the gas and water recovered from the coal matrix reservoirs of the San Juan Basin of the Ignacio Blanco Fruitland field. At the treating site, the gas from coalbed methane wells enters a slug catcher used for water and gas separation. The water that drops out is stored in water tanks. Each water tank has a tank heater used during the winter months to heat the water. The produced water is transferred offsite for disposal. After leaving the slug catcher, the produced gas enters one of two compressors before passing through two glycol dehydrator units equipped with natural gas-fired reboilers to further dry the gas. After dehydration, most of the gas is sent through a custody transfer sales meter to Red Cedar Gathering, while some of the gas is used by BP as fuel gas. The Gas contains only a negligible amount of hydrogen sulfide (H_2S). Therefore, no H_2S removal is necessary.

The primary source of emissions is from the facility's two natural gas-fired four-stroke rich-burn (4SRB) spark ignition (SI) compressor engines, one natural gas-fired 4SRB SI generator engine, one natural gas-fired 4SRB SI pump engine, and two triethylene glycol (TEG) dehydrators.

d. List of all Units and Emission-Generating Activities

BP provided the information contained in Tables 1 and 2 in its initial part 70 permit application. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" emitting units (IEUs) are listed separately in Table 2.

Table 1 – Emission Units
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Description	Control Equipment
TS1-1 TS1-2	2 - Waukesha L5790-GSI (4SRB SI) Compressor Engines, 1215 hp each Serial No.: 401228 Installed: 10/11/2010 Serial No.: 400296 Installed: 7/14/2011	NSCR & AFRC
TS1-3	1 - Waukesha VRG330 (4SRB SI) Generator Engine, 68 hp Serial No.: 399858 Installed: 2012	None
TS1-4	1 - Waukesha F11-G (4SRB SI) Pump Engine, 105 hp Serial No.: 5299365 Installed: 1989	None
TS1-7b TS1-10b	2 –Tri-ethylene Glycol (TEG) Dehydrator Regenerator Vents, 12.5 MMscf/d	None

The Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tpy for all regulated pollutants that are not listed as hazardous air pollutants (HAPs) under Section 112(b) of the Clean Air Act (CAA) and below 1,000 lbs per year or the de minimis level established under Section 112(g), whichever is lower, for HAP emissions.

However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as "insignificant" for the purposes of the Part 70 application are in no way exempt from applicable requirements or any requirements of the Part 70 permit.

BP stated in its Part 70 initial permit application that the emission units in Table 2, below, are insignificant. The application provided calculations for heater/reboiler emissions based on EPA's AP-42 emission factors. BP provided sufficient information, including EPA Tanks 4.0.9d calculations, to verify any emissions from liquids in the tanks were insignificant. This data supports the source's claim that these units qualify as insignificant.

Table 2 – Insignificant Emission Units
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Description
TS1-5 & TS1-6	2 - 500 Mbtu/hr Tank Heaters
TS1-7	1 - 500 Mbtu/hr Glycol Reboiler
TS1-10	1 - 512 Mbtu/hr Glycol Reboiler
TS1-7c & TS1-10c	2 - Dehydrator Flash Tank Vents
TS1-8	Fugitive Emissions
NA	9 - 48 Mbtu/hr Catalytic Space Heaters
NA	4 - 12 Mbtu/hr Catalytic Space Heaters
TS1-11	1 - 375 Mbtu/hr Tank Heater
TS1-12	4 - 500 gallon Lube Oil Tanks
TS1-12	2 - 500 gallon Tri-ethylene Glycol (TEG) Tanks
TS1-12	1 - 300 gallon Ethylene Glycol (EG) Tank
TS1-12	2 - ≤ 95 bbl Used Oil Sumps (by compressors)
TS1-12	1 - ≤ 95 bbl Used Oil Sump (by generator engine)
TS1-12	1 - 300 bbl Oily Water Tank
TS1-12	2 - ≤ 95 bbl Dehydrator Sump Tanks
TS1-12	2 - 500 bbl Produced Water Tanks
TS1-12	1 - Produced Water Pit Tank

e. Facility Construction and Permitting History

Treating Site #1 Central Delivery Point commenced operation in 1989. On July 31, 1997, the EPA issued a PSD permit for the facility. That PSD permit was revised on June 9, 1999. The EPA issued the initial part 71 permit (#V-SU-0001-00.00), in September 1999. The EPA issued a part 71 renewal permit (#V-SU-0001-05.00) in September 2007, which was amended in January 2008. That permit will be replaced by this initial part 70 permit, #V-SUIT-0001-2014.00.

f. Potential to Emit

Under RAC 1-103(51), potential to emit (PTE) is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation, or the effect it would have on emissions, is federally enforceable.

Greenhouse Gas Tailoring Rule

On June 3, 2010, EPA promulgated the final PSD and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule established the applicability criteria that determine which stationary sources and modification projects are subject to PSD and Title V permitting requirements for greenhouse gas (GHG) emissions. As of January 2, 2011, GHGs are regulated NSR pollutants under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds.

For PSD and Title V purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). CO_2-equivalent (CO_2e) is defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential value in Table A-1 of the Greenhouse Gas Reporting Program (40 CFR Part 98, Subpart A, Table A-1).

The Tailoring Rule established the following applicability criteria for GHGs:

PSD Applicability Criteria

PSD applies to GHGs if any of the following conditions are met:

1. The source is a new source otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG PTE equal to or greater than
   - 75,000 tpy CO_2e;
2. The source is a new source and has a GHG PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis
3. A modification to an existing source is otherwise subject to PSD (for another regulated NSR pollutant) and has a GHG emissions increase and net emissions increase:
   - Equal to or greater than 75,000 tpy CO_2e, and
   - Greater than 0 tpy mass basis
4. An existing source has a GHG PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis

   and a modification to an existing source has a GHG emissions increase and net emissions increase:
   - Equal to or greater than 75,000 tpy CO_2e, and
   - Greater than 0 tpy mass basis
5. The source is an existing minor source for PSD, and a modification alone has actual or potential GHG emissions equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 / 250 tpy mass basis

Title V Applicability Criteria

Title V applies to GHGs at the following sources:

1. Existing or newly constructed sources that emit or have a PTE equal to or greater than:
   - 100,000 tpy CO_2e, and
   - 100 tpy mass basis

A detailed summary and guidance of permitting requirements established by the Tailoring Rule can be found in the March 2011 EPA document titled "PSD and Title V Permitting Guidance for Greenhouse Gases", located at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

The PTE for Treating Site #1 Central Delivery Point was listed by BP in Forms "GIS", "PTE", and the various forms "EMISS" of the Part 70 operating permit initial application. Table 3 shows PTE data broken down by each individual emission unit, as well as the total facility-wide PTE.

Table 3 - Potential to Emit
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Regulated Air Pollutants[1,2,3] in Tons per Year								
	NO_X	VOC	SO_2	PM_{10}	CO	Lead	Total HAPs	Largest Single HAP (CH2O)	GHGs (CO_2e mtpy)
TS1-1	11.7	11.7	0.0	0.8	23.5	0.0	0.6	0.6	4,467.0
TS1-2	11.7	11.7	0.0	0.8	23.5	0.0	0.6	0.6	4,467.0
TS1-3	4.9	0.7	0.0	0.0	29.5	0.0	0.1	0.1	270.9
TS1-4	21.0	1.0	0.0	0.1	34.5	0.0	0.1	0.1	410.2
TS1-7b	0.0	29.1	0.0	0.0	0.0	0.0	0.4	0.0	662.9
TS1-10b	0.0	36.6	0.0	0.0	0.0	0.0	0.7	0.0	696.8
IEUs	1.2	2.6	0.0	0.1	1.0	0.0	0.3	0.0	8,725.8
TOTAL	**50.6**	**30.0**	**0.1**	**1.9**	**112.0**	**0.0**	**2.5**	**1.3**	**22,019.3**

[1]Engine units TS1-1 and TS1-2 uncontrolled NOx, CO, and VOC emissions are based on federally enforceable BACT lb/hr and tpy emissions limits per PSD permit PSD-SU-0006-95.00; the pre-control potential to emit (shown in parenthesis) for these units is based upon engine manufacturer emission factors and are shown only for information purposes. SO_2 and PM emissions were calculated using EPA's AP-42 emissions factors. HAP emissions were calculated based on manufacturer supplied emission factors.
[2]Uncontrolled dehydrator emissions are based on GRI GLY-Calc modeled emissions.
[3]GHG emissions calculations based on 40 CFR 98 Subpart C, 98.33(a)(1)(i), Tier 1 Methodology, Equation C-1 and using source specific heat input.

2. Applicable Requirements

The following discussion addresses a selection of the regulations from the Code of Federal Regulations (CFR) at Title 40. Note that this discussion does not include the full spectrum of potentially applicable regulations and is not intended to represent official applicability determinations. These discussions are based on the information provided by BP in its Part 70 initial permit application and are only intended to present the information certified to be true and accurate by the Responsible Official of this facility.

Prevention of Significant Deterioration (PSD) - 40 CFR 52.21

PSD is a preconstruction review requirement of the CAA that applies to proposed projects that are sufficiently large (in terms of emissions) to be a "major" stationary source or "major" modification of an existing stationary source. A new stationary source, or a modification to an existing minor stationary source, is major if the proposed project has the potential to emit of any criteria pollutant regulated under the CAA in amounts equal to or exceeding specified major source thresholds, which are 100 tpy for 28 listed industrial source categories and 250 tpy for all other sources. A source is also major if it has the potential to emit greenhouse gases in amounts of 100,000 tpy CO_2e or greater. PSD also applies to modifications at existing major sources that cause a "significant net emissions increase" at that source. Significance levels for each pollutant are defined in the PSD regulations at 40 CFR 52.21. A modification is a physical change or change in the method of operation.

PSD applies to Treating Site #1 Central Delivery Point. The original construction of the site in 1989 triggered PSD. BP was issued a PSD permit for Treating Site #1 Central Delivery Point on July 31, 1997. That PSD permit was revised on June 9, 1999. The PSD permit requires that the subject engines meet an emission limit of 1.0 g/hp-hr of NOx and 2.0 g/hp-hr of CO. These emission limits are met and maintained through the use of non-selective catalytic reduction (NSCR) and air/fuel ratio controllers (AFRC).

PSD Monitoring, Recordkeeping, and Reporting

In addition to the emission limits, the PSD permit requires quarterly and semi-annual NO_x and CO monitoring for controlled and uncontrolled engines, respectively. Portable analyzers were proposed by BP for conducting the monitoring. The PSD permit also requires that BP keep records of its monitoring and maintenance information and that these records be kept for a period of 5 years. Monitoring data must be reported to EPA semi-annually.

Periodic Monitoring

The previous Part 71 permit for BP TS#1 CDP included periodic monitoring requirements to supplement the PSD permit monitoring requirements for determining compliance with the NOx and CO engine emission limits for units TS1-1 and TS1-2. The monitoring requirements from the Part 71 permit have been incorporated into the Tribe's Part 70 permit. However, upon processing the initial Part 70 permit application for BP TS#1 CDP, the Tribe determined that units TS1-1 and TS1-2 were subject to 40 CFR Part 64, Compliance Assurance Monitoring (CAM). Therefore, in the Part 70 permit, a CAM plan prepared by BP and approved by the Tribe has been added to replace the periodic monitoring requirements for units TS1-1 and TS1-2. BP must be in compliance with the requirements of the CAM plan within 180 days of permit issuance; until such time, the following periodic monitoring requirements will apply:

1. Measure exhaust back pressure;

2. Measure differential pressure and temperature across the catalyst

3. Replace oxygen sensors;

4. Inspect and lubricate air/fuel ratio control valves; and

5 Measure concentrations of CO and NOx in exhaust.

The periodic monitoring requirements will no longer apply upon BP's compliance with the CAM plan.

New Source Performance Standards (NSPS)

40 CFR Part 60, Subpart A: General Provisions. This subpart applies to the owner or operator of any stationary source that contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in Part 60. The general provisions under Subpart A apply to sources that are subject to the specific subparts of Part 60

As explained below, Treating Site #1 Central Delivery Point is not subject to any specific subparts under 40 CFR part 60. **Therefore, the General Provisions of Part 60 do not apply.**

40 CFR Part 60, Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. This rule applies to steam generating units with a heat input capacity of greater than 100 MMBtu/hr and commenced construction, modification, or reconstruction after June 19, 1984

According to the information provided by BP, Treating Site #1 Central Delivery Point has no steam generating units with a heat input capacity greater than 100 MMBtu/hr at the facility. **Therefore, Subpart Db does not apply.**

40 CFR Part 60, Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This rule applies to steam generating units with a maximum design heat capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr and commenced construction, modification, or reconstruction after June 9, 1989.

According to BP, Treating Site #1 Central Delivery Point has no steam generating units with a maximum heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr at the at the facility. **Therefore, Subpart Dc does not apply.**

40 CFR Part 60, Subpart K: Standards of performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR Part 60, Subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

According to BP, Treating Site #1 Central Delivery Point is a drilling and production facility prior to custody transfer. **Therefore, Subpart K does not apply.**

40 CFR Part 60, Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater

than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

According to BP, Treating Site #1 Central Delivery Point is a drilling and production facility prior to custody transfer. **Therefore, Subpart Ka does not apply.**

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters (472bbl, or 19,813 gal).The subpart does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

According to BP, All tanks storing volatile organic liquids at Treating Site #1 Central Delivery Point are less than 75 m^3 (472bbl or 19,813 gal). **Therefore, Subpart Kb does not apply.**

40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. This rule applies to stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), that commenced construction, modification, or reconstruction after October 3, 1977.

According to BP, there are no stationary gas turbines located at Treating Site #1 Central Delivery Point. **Therefore, Subpart GG does not apply.**

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. NGLs are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

According to BP, Treating Site #1 Central Delivery Point does not extract natural gas liquids from field gas, nor does it fractionate mixed NGLs to natural gas products, and thus does not meet the definition of a natural gas processing plant under this subpart. **Therefore, subpart KKK does not apply.**

40 CFR Part 60, Subpart LLL: Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur

recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

According to BP, Treating Site #1 Central Delivery Point does not perform sulfur recovery at the facility. **Therefore, subpart LLL does not apply.**

40 CFR Part 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary combustion ignition (CI) internal combustion engines (ICE) that commence construction (which for the purposes of this subpart is the date the engine is ordered by the owner or operator) after July 11, 2005 and are manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006, or are manufactured after April 1, 2006 and are not fire pump engines

According to BP, there are no stationary compression ignition (CI) internal combustion engines (ICE) located at Treating Site #1 Central Delivery Point. **Therefore, Subpart IIII does not apply.**

40 CFR Part 60, Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that commenced construction, modification or reconstruction after June 12, 2006, where the SI ICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator (See 40 CFR 60.4230(a)).

BP provided the following information:

Table 4 - NSPS Subpart JJJJ Applicability Determination
BP America Production Company, Treating Site #1 Central Delivery Point

Unit[1]	Serial No	Unit Description	Fuel	BHP	Manufacture Date	Commenced Construction Date	Subpart JJJJ Trigger Date - Manufactured on or after
TS1-1	401228	Waukesha L5790-GSI 4SRB Compressor Engine	Natural Gas	1,215	8/11/1989	Prior to 6/12/2006	7/1/2007
TS1-2	400296	Waukesha L5790-GSI 4SRB Compressor Engine	Natural Gas	1,215	10/21/1988	Prior to 6/12/2006	7/1/2007
TS1-3	399858	Waukesha VRG330 4SRB Generator Engine	Natural Gas	68	8/16/1988	Prior to 6/12/2006	7/1/2008
TS1-4	5299365	Waukesha F11-G 4SRB Pump Engine	Natural Gas	105	9/16/1989	Prior to 6/12/2006	7/1/2008

1. Per BP, these engines have not been modified or reconstructed (as defined in Part 60) since June 12, 2006.

According to BP, Units TS1-1 and TS1-2 were manufactured prior to July 1, 2007 (trigger date for engines with a maximum engine power greater than or equal to 500 hp). Units TS1-3 and TS1-4 were manufactured prior to July 1, 2008 (trigger date for engines with a maximum engine power less than 500 hp). The engines have not been reconstructed or modified (as defined in §60.15) since June 12, 2006. **Therefore, Subpart JJJJ does not apply**.

Should BP propose to install a replacement engine for Units TS1-1, TS1-2, TS1-3, or TS1-4 that is subject to Subpart JJJJ, BP will not be allowed to use the off permit changes provision, and will be required to submit a minor permit modification application to incorporate Subpart JJJJ requirements into the permit.

40 CFR Part 60, Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005. The rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour.

According to BP, there are no stationary gas turbines located at Treating Site #1 Central Delivery Point. **Therefore, Subpart KKKK does not apply.**

40 CFR Part 60, Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011. Affected facilities under this subpart include gas wells, compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units.

According to BP, Treating Site #1 Central Delivery Point does not have any affected facilities under the rule that commenced construction after August 23, 2011. **Therefore, Subpart OOOO does not apply**.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for HAPs that regulate specific categories of sources that emit one or more HAP regulated pollutants under the CAA. The general provisions under Subpart A apply to sources that are subject to the specific subparts of Part 63.

As explained below, Treating Site #1 Central Delivery Point is subject to the recordkeeping requirements of 40 CFR 63 Subparts HH and to the January 30, 2013 revisions to 40 CFR part 63, subpart ZZZZ. Therefore the General Provisions of Part 63 apply. Additionally, though units TS1-7b & TS1-10b are not subject to the relevant standards of their relevant source category, subpart HH, a record of an applicability determination demonstrating that the units are not subject to the relevant Part 63 standards must be kept (per § 63.10(b)(3)) at BP's Durango Operations

Center for 5 years after the determinations or until a source changes its operations to become an affected source.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are area or major sources of HAPs, as defined by §63.761, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. For the purpose of this subpart, natural gas enters the transmission and storage category after the natural gas processing plant, when present. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption

Those sources whose maximum natural gas throughput, as appropriately calculated per §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day and a facility-wide actual annual average hydrocarbon liquid throughput less than 39,700 liters per day are exempt from the requirements of this subpart.

Source Aggregation

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline Central Delivery Point or pump station shall not be aggregated with emissions from other similar units.

2) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination.

Facility

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in Subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a Central Delivery Point that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGLs from field gas, or the fractionation of mixed NGLs to natural gas products, or a combination of both. A treating plant or gas plant that does not engage in these activities is considered to be a production field facility.

Major Source Determination for Production Field Facilities

The definition of major source in subpart HH (at 40 CFR 63.761) states, in part, that only emissions from the dehydration units and storage vessels at production field facilities shall be aggregated when comparing to the major source thresholds.

For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability

40 CFR Part 63, Subpart HH applies also to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for glycol dehydration units found at oil and gas production facilities based on their geographical location.

Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol recirculation pump rate optimized or operators must document that uncontrolled annual actual benzene emissions are less than 0.9 megagrams (1,984 lbs.).

Any source that determines that it is not a major source but has actual emissions of 5 tons per year of a single HAP or 12.5 tons per year of a combination of HAP (i.e. 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months.

Applicability of Subpart HH to Treating Site #1 Central Delivery Point

According to BP, the Treating Site #1 Central Delivery Point is located prior to the point of custody transfer and is therefore considered a production field facility and not a natural gas transmission or storage facility. Potential HAP emissions from the glycol dehydration units and storage vessels at the facility are less than the major source thresholds of 25 tpy total HAPS and 10 tpy of a single HAP. Therefore, Treating Site #1 Central Delivery Point is considered an area source of HAPs according to 40 CFR Part 63, subpart HH. Uncontrolled actual average benzene emissions from each dehydration unit are less than 0.9 megagrams. Per 40 CFR 63.764(e)(1)(ii), the dehydration units are exempt from the 40 CFR 63.764(d) general standards for area sources. **Therefore, only recordkeeping requirements apply to the facility.**

40 CFR Part 63, Subpart HHH: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This subpart applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are a major source of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines are used for long distance transport (excluding processing).

According to BP, Treating Site #1 Central Delivery Point is a natural gas production facility and not a natural gas transmission or storage facility. **Therefore, Subpart HHH does not apply.**

40 CFR Part 63, Subpart ZZZZ (RICE MACT): National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary spark ignition internal combustion engines (SI ICE) and stationary compression ignition internal combustion engines (CI ICE).

For the purposes of this standard, construction or reconstruction is as defined in §63.2.

Summary of Applicability to Engines at Major HAP Sources

Major HAP Sources			
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**
SI ICE – All1	≥ 500 hp	New	On or After: 12/19/2002
SI ICE – 4SRB	> 500 hp	Existing	Before: 12/19/2002
SI ICE – All1	≤ 500 hp	New	On or After: 6/12/2006
SI ICE - All1	≤ 500 hp	Existing	Before: 6/12/2006
CI ICE - All2	≥ 500 hp	New	On or After: 12/19/2002
CI ICE – Non Emergency	> 500 hp	Existing	Before: 12/19/2002
CI ICE – All2	≤ 500 hp	New	On or After: 6/12/2006
CI ICE – All2	≤ 500 hp	Existing	Before: 6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Summary of Applicability to Engines at Area Hap Sources

Area HAP Sources			
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**
SI ICE - All[1]	All hp	New	On or After: 6/12/2006
SI ICE - All[1]	All hp	Existing	Before: 6/12/2006
CI ICE - All[2]	All hp	New	On or After: 6/12/2006
CI ICE - All[2]	All hp	Existing	Before: 6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Table 5-Applicability of 40 CFR 63, Subpart ZZZZ to Treating Site #1 Central Delivery Point:

Unit	Serial Number	Unit Description	Fuel	Site Rated BHP	Commenced Construction, Reconstruction, or Modification Date	Site Installation Date
TS1-1	401228	Waukesha L5790-GSI Compressor Engine	Natural Gas	1,194	Prior to 6/12/2006	10/11/2010
TS1-2	400296	Waukesha l5790-GSI Compressor Engine	Natural Gas	1,194	Prior to 6/12/2006	07/14/2011
TS1-3	399858	Waukesha VRG 330 Generator Engine	Natural Gas	57	Prior to 6/12/2006	2012
TS1-4	5299365	Waukesha F11-G	Natural Gas	97	Prior to 6/12/2006	1989

According to BP Treating Site #1 CDP is an area source of HAPs as defined in this subpart. All currently permitted engines at the facility commenced construction or reconstruction prior to June 12, 2006 and are therefore considered existing stationary RICE for this subpart. On January 30, 2013, the Environmental Protection Agency (EPA) published additional amendments to this subpart, which outline requirements for a new subcategory of "Remote Stationary RICE" located at area sources of HAPs, as defined by 40 CFR 63.6675. According to BP units TS1-1 and TS2-2 qualify as existing 4SRB remote stationary RICE greater than 500 site-rated horsepower located at an area source of HAPs, have an initial compliance date of October 19, 2013, and must re-evaluate the remote status of their stationary RICE every 12 months, per 40 CFR 63.6603(f). Units TS1-3 and TS1-4 are existing 4SRB engines less than or equal to 500 site-rated horsepower located at an area source of HAPs and have an initial compliance date of October 19, 2013. **Therefore units TS1-1, TS1-2, TS1-3, and TS1-4 are subject to the applicable requirements for area sources found in 40 CFR Part 63, Subpart ZZZZ.** As required by 40 CFR 63.6603 for existing SI RICE located at an area source of HAPs, emissions units TS1-1, TS1-2, TS1-3, and TS1-4 must comply with the applicable work, operation and management practices outlined in Table 2d and 6 of Subpart ZZZZ.

40 CFR Part 63, Subpart DDDDD (Boiler MACT): National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. This rule establishes national emission limitations and work practice standards for HAPs emitted from new and existing industrial boilers, institutional boilers, commercial boilers, and process heaters that are located at major sources of HAPs, as defined by 40 CFR 63.7575. Boilers or process heaters that combust natural gas for fuel or have a maximum designed heat input capacity less than 10 MMBtu/hr are subject to work practice standards in lieu of emission limits For the purposes of this subpart, an affected unit is an existing unit if it was constructed prior to June 4, 2010.

According to BP the Treating Site #1 Central Delivery Point is a pipeline compressor station located prior to the point of custody transfer, and is a production field facility. The definition of a major source for oil and natural gas production facilities at 40 CFR 63.7575(1)-(3) allows only the aggregation of HAP emissions from the glycol dehydration units and storage vessels with the potential for flash emissions at the facility for the major source determination. Based on this major source determination the facility HAP emissions are below the major source thresholds. **Therefore, Subpart DDDDD does not apply.**

40 CFR Part 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers. This rule establishes national emission standards and operating limitations for HAPs emitted from new and existing industrial boilers, institutional boilers, and commercial boilers, as defined in § 63.11237, and are located at area sources of HAPs, as defined in § 63.2, except as specified in § 63.11195. For the purposes of this subpart, an affected unit is an existing unit if it was constructed prior to June 4, 2010.

According to BP, no equipment at Treating Site #1 Central Delivery Point meets the definition of a boiler as defined in § 63.11237, **Therefore, Subpart JJJJJJ does not apply.**

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Compliance Assurance Monitoring (CAM) Rule

40 CFR Part 64: Compliance Assurance Monitoring Provisions. According to 40 CFR 64.2(a), the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) at a major source that is required to obtain a Part 70 or Part 71 permit if the unit satisfies all of the following criteria:

1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant other than an emissions limitation or standard that is exempt under §64.2(b)(1);

"§64.2(b)(1): Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:

(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to Section 111 or 112 of the Act;
(ii) Stratospheric ozone protection requirements under Title VI of the Act;
(iii) Acid Rain Program requirements pursuant to Sections 404, 405, 406, 407(a), 407(b) or 410 of the Act;
(iv) Emissions limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions with a source or between sources;
(v) An emissions cap that meets the requirements specified in §70.4(b)(12) or §71.6(a)(13)(iii) of this chapter;
(vi) Emission limitations or standards for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1."

"§64.1: Continuous compliance method means a method, specified by the applicable standard or an applicable permit condition, which:

(1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and
(2) Provides data either in units of the standard or correlated directly with the compliance limit."

2) The unit uses a control device to achieve compliance with any such limit or standard; and

3) The unit has pre-control device emissions of the applicable regulated pollutant that are equal to or greater than 100% of the amount, in tons per year, required for a source to be classified as a major source.

According to BP, Treating Site #1 Central Delivery Point is a major source of NO_x and CO. Emission units TS1-1 and TS1-2 are both PSEUs with pre-controlled emissions that equal or exceed 100% of NO_x and CO thresholds and use a control device to comply with an emission limitation**. Therefore, units TS1-1 and TS1-2 are subject to CAM requirements**

Chemical Accident Prevention Program

40 CFR Part 68: Chemical Accident Prevention Provisions. This rule applies to stationary sources that manufacture, process, use, store, or otherwise handle more than the threshold quantity of a regulated substance in a process. Regulated substances include 77 toxic and 63 flammable substances which are potentially present in the natural gas stream entering the facility and in the storage vessels located at the facility. The quantity of a regulated substance in a process is determined according to the procedures presented under §68.115. The regulations at §68.115(b)(l) and (2)(i) indicate that toxic and flammable substances in a mixture do not need to be considered when determining whether more than a threshold quantity is present at a stationary source if the concentration of the substance is below one percent by weight of the mixture. The regulations at §68.115(b)(2)(iii) indicates that prior to entry into a natural gas processing plant, regulated substances in naturally occurring hydrocarbon mixtures need not be considered when determining whether more than a threshold quantity is present at a stationary source. Naturally occurring hydrocarbon mixtures include condensate, field gas, and produced water.

Based on BP's application, Treating Site #1 Central Delivery Point does not have regulated substances above the threshold quantities in this rule. **Therefore the facility is not subject to the requirement to develop and submit a risk management plan.**

Stratospheric Ozone and Climate Protection

40 CFR Part 82, Subpart F: Air Conditioning Units. According to BP, there are no air conditioning units at the Treating Site #1 Central Delivery Point that contain Class I or Class II refrigerants (chlorofluorocarbons (CFCs)). However, should BP obtain any air conditioning units at the Treating Site #1 Central Delivery Point that contain Class I or Class II refrigerants then it must comply

with the standards of part 82 subpart F for recycling and emissions reduction if they service, maintain, or repair the air conditioning units in any way or if they dispose of the units.

40 CFR Part 82, Subpart H: Halon Fire Extinguishers. According to BP, there are no halon fire extinguishers at Treating Site #1 Central Delivery Point. However, should BP obtain any halon fire extinguishers, then it must comply with the standards of 40 CFR Part 82, Subpart H for halon emissions reduction, if it services, maintains, tests, repairs, or disposes of equipment that contains halon or uses such equipment during technician training. Specifically, BP would be required to comply with 40 CFR Part 82 and submit an application for a revision to this Title V permit.

Mandatory Greenhouse Gas Reporting

40 CFR Part 98: Mandatory Greenhouse Gas Reporting. This rule requires sources above certain emission thresholds to calculate, monitor, and report greenhouse gas emissions. The requirements of 40 CFR Part 98 and CAA §307(d)(1)(V), the CAA authority under which 40 CFR Part 98 was promulgated, however, need not be included in a part 70 permit because those requirements are not included in the definition of "applicable requirement" in either 40 CFR part 70 or RAC 1-103(11). Although the rule is not an applicable requirement under 40 CFR Part 70 or the RAC, the source is not relieved from the requirement to comply with the rule separately from compliance with its Part 70 operating permit. It is the responsibility of each source to determine whether Part 98 is applicable and to comply, if necessary.

3. Tribal Authority

Reservation Air Code: The Reservation Air Code was adopted pursuant to the authority vested in the Southern Ute Indian Tribe/State of Colorado Environmental Commission by (1) the Intergovernmental Agreement Between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation dated December 13, 1999, (2) tribal law (Resolution of the Council of the Southern Ute Indian Tribe # 00-09), (3) State law (C.R.S. § 24- 62-101), and (4) as recognized in federal law (Act of October 18, 2004, Pub. L. No. 108-336, 118 Stat.1354).

Title V Permitting Program: On March 2, 2012, the EPA determined that the Southern Ute Indian Tribe of the Southern Ute Indian Reservation had met the requirements of 40 CFR § 70.4(b) for full approval to administer its Clean Air Act Title V, Part 70 Permitting Program (Program). In concert with that Program approval, the EPA also found that the Tribe met the requirements of Section 301(d)(2) of the CAA and 40 CFR § 49.6 for treatment "in the same manner as a state" for the purposes of issuing CAA Title V, Part 70 operating permits. The EPA promulgated its approval of the Tribe's applications on March 15, 2012 (77 FR 15267).

NSPS and NESHAP Delegation: On September 6, 2013, the Southern Ute Indian Tribe received delegation from the EPA to incorporate by reference into the Reservation Air Code and enforce certain subparts of the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) under Sections 111 and 112 of the Clean Air Act, respectively (78

FR 40635). These NSPS and NESHAP subparts generally apply to oil and gas operations within the exterior boundaries of the Southern Ute Indian Reservation and were adopted unchanged into the Reservation Air Code as Parts 2 and 3.

Southern Ute Indian Tribe Minor Source Program: The Southern Ute Indian Tribe/State of Colorado Environmental Commission is currently developing a Minor Source Program in order to fill a regulatory gap wherein sources of air pollution located on the Reservation have been subject to fewer requirements than similar sources located on land under the jurisdiction of a state air pollution control agency. Until such time EPA approves the Minor Source Program as part of a TIP under the Tribal Authority Rule affected sources must comply with the federal rule "Review of New Sources and Modifications in Indian country" that was published on July 1, 2011. This rule requires new and existing synthetic minor sources currently operating under federal operating permits for sources in Indian Country (regulated at 40 CFR Part 71), as well as sources proposing minor modifications at existing major sources, to submit applications to the region starting August 30, 2011. After September 2, 2014 all true minor sources that intend to construct or modify will have to apply for a preconstruction permit.

Implementation Plans: Since Treating Site #1 Central Delivery Point is located in Indian Country, the State of Colorado's implementation plan does not apply to this source. In addition, no tribal implementation plan (TIP) has been submitted and approved for the Southern Ute Indian Tribe, and EPA has not promulgated a federal implementation plan (FIP) for the area of jurisdiction governing the Southern Ute Indian Reservation. Therefore, Treating Site #1 Central Delivery Point is not subject to any implementation plan.

4. Public Participation

a. Public Notice

Per RAC § 2-109, all Part 70 draft operating permits shall be publicly noticed and made available for public comment. Public notice is given by publication in a newspaper of general circulation in the area where the source is located or in a state publication designed to give general public notice, to persons on a mailing list developed by the Tribe, including those who request in writing to be on the list, and by other means if necessary to assure adequate notice to the affected public. If an interested person would like to be added to the Tribe's mailing list to be informed of future actions on permits issued by the Tribe, please send your name and address:

by United State Postal Service to:	by any other delivery service to:
Southern Ute Indian Tribe Environmental Programs Division Part 70 Program PO Box 737 MS #84 Ignacio, Colorado 81137	Southern Ute Indian Tribe Environmental Programs Division Part 70 Program 398 Ouray Drive Ignacio, Colorado 81137

Public notice will be published in the Durango Herald as detailed in the cover letter of this draft permit package, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for Comment

Members of the public will be given an opportunity to review a copy of the draft permit prepared by the Tribe, the application, this statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents are available at:

Southern Ute Indian Tribe
Environmental Programs Division
Air Quality Program
115 County Road 517
Ignacio, Colorado 81137

All documents are available for review at the Southern Ute Indian Tribe's Environmental Programs Division office Monday through Friday from 9:00 a.m. to 4:00 p.m. (excluding holidays).

Any interested person may submit written comments on the draft Part 70 operating permit during the public comment period to the Part 70 Permit Contact at the address listed above. The Tribe will consider and address comments in making a final decision on the permit. The Tribe keeps a record of the commenters and of the issues raised during the public participation process.

Anyone, including the applicant, who believes any condition of the draft permit is inappropriate should raise all reasonably ascertainable issues and submit all arguments supporting his or her position by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has already been submitted as part of the administrative record in the same proceeding or consists of Environmental Commission, tribal, state or Federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to the Part 70 Permit Contact, at the address listed above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, the Tribe will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. The Tribe will provide public notice of the public hearing. If a public hearing is held, any person may submit oral or written statements and data concerning the draft permit.

d. Public Petitions to the Administrator

In the event the Administrator of the United States Environmental Protection Agency does not object to issuance of the permit, on the basis that it would not be in compliance with applicable requirements, within its 45-day review period, any person may then petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objections arose after such period. If the Administrator objects to a permit as a result of this petition, the Tribe shall not issue the permit until the Administrator's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and before the Administrator's objection.

e. Appeal of Permits

Within 60 days after the Tribe's final permit action, an applicant, any person who filed comments on the draft permit or participated in the public hearing, and any other person who could obtain judicial review of that action under applicable law, may appeal to the Environmental Commission in accordance with the RAC and the Commission's Procedural Rules. Solely for the purpose of obtaining administrative review before the Commission for failure to take final permit action; final permit action shall include the failure of the Tribe to take final action on an application for a permit within the time required.

Petitions for administrative review of final permit actions can be filed after the deadline designated by the Commission only if they are based solely on grounds arising after the deadline for administrative review. Such petitions shall be filed no later than 60 days after the new grounds for review arise. If the final permit action being challenged is the Tribe's failure to take final action, a petition for administrative review may be filed any time before the Tribe denies or issues the final permit.

f. Notice to Affected States/Tribes

As described in RAC § 2-109(3), public notice will be given by notifying all affected programs. The following entities will be notified:

- State of Colorado, Department of Public Health and Environment
- State of New Mexico, Environment Department
- Ute Mountain Ute Tribe, Environmental Programs Department
- Navajo Tribe, Navajo Nation EPA
- Jicarilla Tribe, Environmental Protection Office
- National Park Service, Air Resources Division, Denver, CO
- U.S. Department of Agriculture, United States Forest Service, Rocky Mountain Region

c. Description of Operations

Treating Site #1 Central Delivery Point is a central facility used to separate and dry the gas and water recovered from the coal matrix reservoirs of the San Juan Basin of the Ignacio Blanco Fruitland field. At the treating site, the gas from coalbed methane wells enters a slug catcher used for water and gas separation. The water that drops out is stored in water tanks. Each water tank has a tank heater used during the winter months to heat the water. The produced water is transferred offsite for disposal. After leaving the slug catcher, the produced gas enters one of two compressors before passing through two glycol dehydrator units equipped with natural gas-fired reboilers to further dry the gas. After dehydration, most of the gas is sent through a custody transfer sales meter to Red Cedar Gathering, while some of the gas is used by BP as fuel gas. The Gas contains only a negligible amount of hydrogen sulfide (H_2S). Therefore, no H_2S removal is necessary.

The primary source of emissions is from the facility's two natural gas-fired four-stroke rich-burn (4SRB) spark ignition (SI) compressor engines, one natural gas-fired 4SRB SI generator engine, one natural gas-fired 4SRB SI pump engine, and two triethylene glycol (TEG) dehydrators.

d. List of all Units and Emission-Generating Activities

BP provided the information contained in Tables 1 and 2 in its initial part 70 permit application. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" emitting units (IEUs) are listed separately in Table 2.

Table 1 – Emission Units
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Description	Control Equipment
TS1-1 TS1-2	2 - Waukesha L5790-GSI (4SRB SI) Compressor Engines, 1215 nameplate rated bhp each Serial No.: 401228 Installed: 10/11/2010 Serial No.: 400296 Installed: 7/14/2011	NSCR & AFRC
TS1-3	1 - Waukesha VRG330 (4SRB SI) Generator Engine, 68 nameplate rated bhp Serial No.: 399858 Installed: 2012	None
TS1-4	1 - Waukesha F11-G (4SRB SI) Pump Engine, 105 nameplate rated bhp Serial No.: 5299365 Installed: 1989	None
TS1-7b TS1-10b	2 –Tri-ethylene Glycol (TEG) Dehydrator Regenerator Vents, 12.5 MMscf/d	None
*TS1-9	1 – Waukesha F-18GL (4SLB) Engine, 375 nameplate rated bhp Serial No.: N/A Installed: Removed	None

*TS1-9 has been shut-down and permanently removed from the facility. However, this engine remains in the part 70 permit as it is still listed in the PSD permit for this facility.

The Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tpy for all regulated pollutants that are not listed as hazardous air pollutants (HAPs) under Section 112(b) of the Clean Air Act (CAA) and below 1,000 lbs per year or the de minimis level established under Section 112(g), whichever is lower, for HAP emissions. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as "insignificant" for the purposes of the Part 70 application are in no way exempt from applicable requirements or any requirements of the Part 70 permit.

BP stated in its Part 70 initial permit application that the emission units in Table 2, below, are insignificant. The application provided calculations for heater/reboiler emissions based on EPA's AP-42 emission factors. BP provided sufficient information, including EPA Tanks 4.0.9d calculations, to verify any emissions from liquids in the tanks were insignificant. This data supports the source's claim that these units qualify as insignificant.

Table 2 – Insignificant Emission Units
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Description
TS1-5 & TS1-6	2 - 500 Mbtu/hr Tank Heaters
TS1-7	1 - 500 Mbtu/hr Glycol Reboiler
TS1-10	1 - 512 Mbtu/hr Glycol Reboiler
TS1-7c & TS1-10c	2 - Dehydrator Flash Tank Vents
TS1-8	Fugitive Emissions
NA	9 - 48 Mbtu/hr Catalytic Space Heaters
NA	4 - 12 Mbtu/hr Catalytic Space Heaters
TS1-11	1 - 375 Mbtu/hr Tank Heater
TS1-12	4 - 500 gallon Lube Oil Tanks
TS1-12	2 - 500 gallon Tri-ethylene Glycol (TEG) Tanks
TS1-12	1 - 300 gallon Ethylene Glycol (EG) Tank
TS1-12	2 - ≤ 95 bbl Used Oil Sumps (by compressors)
TS1-12	1 - ≤ 95 bbl Used Oil Sump (by generator engine)
TS1-12	1 - 300 bbl Oily Water Tank
TS1-12	2 - ≤ 95 bbl Dehydrator Sump Tanks
TS1-12	2 - 500 bbl Produced Water Tanks
TS1-12	1 - Produced Water Pit Tank

e. Facility Construction and Permitting History

Treating Site #1 Central Delivery Point commenced operation in 1989. On July 31, 1997, the EPA issued a PSD permit for the facility. That PSD permit was revised on June 9, 1999. The EPA issued the initial part 71 permit (#V-SU-0001-00.00), in September 1999. The EPA issued a part 71 renewal permit (#V-SU-0001-05.00) in September 2007, which was amended in January 2008. That permit will be replaced by this initial part 70 permit, #V-SUIT-0001-2014.00.

f. Potential to Emit

Under RAC 1-103(51), potential to emit (PTE) is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. A ny physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation, or the effect it would have on emissions, is federally enforceable.

Greenhouse Gas Tailoring Rule

On June 3, 2010, E PA promulgated the final PSD and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule established the applicability criteria that determine which stationary sources and modification projects are subject to PSD and Title V permitting requirements for greenhouse gas (GHG) emissions. As of January 2, 2011, GHGs are regulated NSR pollutants under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds.

For PSD and Title V purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). CO_2-equivalent (CO_2e) is defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential value in Table A-1 of the Greenhouse Gas Reporting Program (40 CFR Part 98, Subpart A, Table A-1).

The Tailoring Rule established the following applicability criteria for GHGs:

PSD Applicability Criteria
PSD applies to GHGs if any of the following conditions are met: 1. The source is a new source otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG PTE equal to or greater than • 75,000 tpy CO_2e; 2. The source is a new source and has a GHG PTE equal to or greater than: • 100,000 tpy CO_2e, and • 100 / 250 tpy mass basis 3. A modification to an existing source is otherwise subject to PSD (for another regulated NSR pollutant) and has a GHG emissions increase and net emissions increase: • Equal to or greater than 75,000 tpy CO_2e, and • Greater than 0 tpy mass basis 4. An existing source has a GHG PTE equal to or greater than: • 100,000 tpy CO_2e, and • 100 / 250 tpy mass basis and a modification to an existing source has a GHG emissions increase and net emissions increase: • Equal to or greater than 75,000 tpy CO_2e, and • Greater than 0 tpy mass basis 5. The source is an existing minor source for PSD, and a modification alone has actual or potential GHG emissions equal to or greater than: • 100,000 tpy CO_2e, and • 100 / 250 tpy mass basis

Title V Applicability Criteria
Title V applies to GHGs at the following sources: 1. Existing or newly constructed sources that emit or have a PTE equal to or greater than: • 100,000 tpy CO_2e, and • 100 tpy mass basis

A detailed summary and guidance of permitting requirements established by the Tailoring Rule can be found in the March 2011 EPA document titled "PSD and Title V Permitting Guidance for Greenhouse Gases", located at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

The PTE for Treating Site #1 Central Delivery Point was listed by BP in Forms "GIS", "PTE", and the various forms "EMISS" of the Part 70 operating permit initial application. Table 3 shows PTE data broken down by each individual emission unit, as well as the total facility-wide PTE.

Table 3 - Potential to Emit
BP America Production Company, Treating Site #1 Central Delivery Point

Emission Unit ID	Regulated Air Pollutants[1,2,3] in Tons per Year Uncontrolled emissions shown in parenthesis								
	NO_X	VOC	SO_2	PM_{10}	CO	Lead	Total HAPs	Largest Single HAP (CH2O)	GHGs (CO_2e mtpy)
TS1-1	11.7 (211.2)	23.5	0.0	0.8	23.5 (328.5)	0.0	0.6	0.6	4,467.0
TS1-2	11.7 (211.2)	23.5	0.0	0.8	23.5 (328.5)	0.0	0.6	0.6	4,467.0
TS1-3	4.9	0.7	0.0	0.0	29.5	0.0	0.1	0.1	270.9
TS1-4	21.0	1.0	0.0	0.1	34.5	0.0	0.1	0.1	410.2
TS1-7b	0.0	29.1	0.0	0.0	0.0	0.0	0.4	0.0	662.9
TS1-10b	0.0	36.6	0.0	0.0	0.0	0.0	0.7	0.0	696.8
IEUs	1.2	2.6	0.0	0.1	1.0	0.0	0.3	0.0	8,725.8
TOTAL	**50.6**	**116.8**	**0.1**	**1.9**	**112.0**	**0.0**	**2.5**	**1.3**	**22,019.3**

[1]Engine units TS1-1 and TS1-2 controlled NOx, and CO, emissions are based on federally enforceable BACT lb/hr and tpy emissions limits per PSD permit PSD-SU-0006-95.00; the uncontrolled emissions (shown in parenthesis) for these units are based upon engine manufacturers emission factors and are shown for 40 CFR Part 64, Compliance Assurance Monitoring applicability. SO_2 and PM emissions were calculated using EPA's AP-42 emissions factors. HAP emissions were calculated based on manufacturer supplied emission factors.
[2]Uncontrolled dehydrator emissions are based on GRI GLY-Calc modeled emissions.
[3]GHG emissions calculations based on 40 CFR 98 Subpart C, 98.33(a)(1)(i), Tier 1 Methodology, Equation C-1 and using source specific heat input.

2. Applicable Requirements

The following discussion addresses a selection of the regulations from the Code of Federal Regulations (CFR) at Title 40. Note that this discussion does not include the full spectrum of potentially applicable regulations and is not intended to represent official applicability determinations. These discussions are based on the information provided by BP in its Part 70 initial permit application and are only intended to present the information certified to be true and accurate by the Responsible Official of this facility.

Prevention of Significant Deterioration (PSD) - 40 CFR 52.21

PSD is a preconstruction review requirement of the CAA that applies to proposed projects that are sufficiently large (in terms of emissions) to be a “major” stationary source or “major” modification of an existing stationary source. A new stationary source, or a modification to an existing minor stationary source, is major if the proposed project has the potential to emit of any criteria pollutant regulated under the CAA in amounts equal to or exceeding specified major source thresholds, which are 100 tpy for 28 listed industrial source categories and 250 tpy for all other sources. A source is also major if it has the potential to emit greenhouse gases in amounts of 100,000 tpy CO_2e or greater. PSD also applies to modifications at existing major sources that cause a “significant net emissions increase” at that source. Significance levels for each pollutant are defined in the PSD regulations at 40 CFR 52.21. A modification is a physical change or change in the method of operation.

PSD applies to Treating Site #1 Central Delivery Point. The original construction of the site in 1989 triggered PSD. BP was issued a PSD permit for Treating Site #1 Central Delivery Point on July 31, 1997. That PSD permit was revised on June 9, 1999. The PSD permit requires that the subject engines meet an emission limit of 1.0 g/hp-hr of NOx and 2.0 g/hp-hr of CO. These emission limits are met and maintained through the use of non-selective catalytic reduction (NSCR) and air/fuel ratio controllers (AFRC).

PSD Monitoring, Recordkeeping, and Reporting

In addition to the emission limits, the PSD permit requires quarterly and semi-annual NO_x and CO monitoring for controlled and uncontrolled engines, respectively. Portable analyzers were proposed by BP for conducting the monitoring. The PSD permit also requires that BP keep records of its monitoring and maintenance information and that these records be kept for a period of 5 years. Monitoring data must be reported to EPA semi-annually.

Periodic Monitoring

The previous Part 71 permit for BP TS#1 CDP included periodic monitoring requirements to supplement the PSD permit monitoring requirements for determining compliance with the NOx and CO emission limits for units TS1-1 and TS1-2. The monitoring requirements from the Part 71 permit have been incorporated into the Tribe’s Part 70 permit. However, upon processing the initial Part 70 permit application for BP TS#1 CDP, the Tribe determined that units TS1-1 and TS1-2 were subject to 40 CFR Part 64, Compliance Assurance Monitoring (CAM). Therefore, in the Part 70 permit, a CAM plan prepared by BP and approved by the Tribe has been added to replace the periodic monitoring requirements for units TS1-1 and TS1-2. BP must be in compliance with the requirements of the CAM plan within 180 days of permit issuance; until such time, the following periodic monitoring requirements will apply:

1. Measure exhaust back pressure;

2. Measure differential pressure and temperature across the catalyst

3. Replace oxygen sensors;

4. Inspect and lubricate air/fuel ratio control valves; and

5 Measure concentrations of CO and NOx in exhaust.

The periodic monitoring requirements will no longer apply upon BP's compliance with the CAM plan.

New Source Performance Standards (NSPS)

40 CFR Part 60, Subpart A: General Provisions. This subpart applies to the owner or operator of any stationary source that contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in Part 60. The general provisions under Subpart A apply to sources that are subject to the specific subparts of Part 60

As explained below, Treating Site #1 Central Delivery Point is not subject to any specific subparts under 40 CFR Part 60. **Therefore, the General Provisions of Part 60 do not apply.**

40 CFR Part 60, Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. This rule applies to steam generating units with a heat input capacity of greater than 100 MMBtu/hr and commenced construction, modification, or reconstruction after June 19, 1984

According to the information provided by BP, Treating Site #1 Central Delivery Point has no steam generating units with a heat input capacity greater than 100 MMBtu/hr at the facility. **Therefore, Subpart Db does not apply.**

40 CFR Part 60, Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This rule applies to steam generating units with a maximum design heat capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr and commenced construction, modification, or reconstruction after June 9, 1989.

According to BP, Treating Site #1 Central Delivery Point has no steam generating units with a maximum heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr at the at the facility. **Therefore, Subpart Dc does not apply.**

40 CFR Part 60, Subpart K: Standards of performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR Part 60, Subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

According to BP, Treating Site #1 Central Delivery Point is a drilling and production facility prior to custody transfer. **Therefore, Subpart K does not apply.**

40 CFR Part 60, Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

According to BP, Treating Site #1 Central Delivery Point is a drilling and production facility prior to custody transfer. **Therefore, Subpart Ka does not apply.**

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters (472bbl, or 19,813 gal).The subpart does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

According to BP, All tanks storing volatile organic liquids at Treating Site #1 Central Delivery Point are less than 75 m^3 (472bbl or 19,813 gal). **Therefore, Subpart Kb does not apply.**

40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. This rule applies to stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), that commenced construction, modification, or reconstruction after October 3, 1977.

According to BP, there are no stationary gas turbines located at Treating Site #1 Central Delivery Point. **Therefore, Subpart GG does not apply.**

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. NGLs are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

According to BP, Treating Site #1 Central Delivery Point does not extract natural gas liquids from field gas, nor does it fractionate mixed NGLs to natural gas products, and thus does not meet the definition of a natural gas processing plant under this subpart. **Therefore, subpart KKK does not apply.**

40 CFR Part 60, Subpart LLL: Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. This rule applies to sweetening units and sulfur recovery units at

onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

According to BP, Treating Site #1 Central Delivery Point does not perform sulfur recovery at the facility. **Therefore, subpart LLL does not apply.**

40 CFR Part 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary combustion ignition (CI) internal combustion engines (ICE) that commence construction (which for the purposes of this subpart is the date the engine is ordered by the owner or operator) after July 11, 2005 and are manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006, or are manufactured after April 1, 2006 and are not fire pump engines

According to BP, there are no stationary compression ignition (CI) internal combustion engines (ICE) located at Treating Site #1 Central Delivery Point. **Therefore, Subpart IIII does not apply.**

40 CFR Part 60, Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that commenced construction, modification or reconstruction after June 12, 2006, where the SI ICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator (See 40 CFR 60.4230(a)).

BP provided the following information:

Table 4 - NSPS Subpart JJJJ Applicability Determination
BP America Production Company, Treating Site #1 Central Delivery Point

Unit[1]	Serial No	Unit Description	Fuel	Maximum BHP	Manufacture Date	Commenced Construction Date	Subpart JJJJ Trigger Date - Manufactured on or after
TS1-1	401228	Waukesha L5790-GSI 4SRB Compressor Engine	Natural Gas	1,215	8/11/1989	Prior to 6/12/2006	7/1/2007
TS1-2	400296	Waukesha L5790-GSI 4SRB Compressor Engine	Natural Gas	1,215	10/21/1988	Prior to 6/12/2006	7/1/2007
TS1-3	399858	Waukesha VRG330 4SRB Generator Engine	Natural Gas	68	8/16/1988	Prior to 6/12/2006	7/1/2008
TS1-4	5299365	Waukesha F11-G 4SRB Pump Engine	Natural Gas	105	9/16/1989	Prior to 6/12/2006	7/1/2008

1. Per BP, these engines have not been modified or reconstructed (as defined in Part 60) since June 12, 2006.

According to BP, Units TS1-1 and TS1-2 were manufactured prior to July 1, 2007 (trigger date for engines with a maximum engine power greater than or equal to 500 hp). Units TS1-3 and TS1-4 were manufactured prior to July 1, 2008 (trigger date for engines with a maximum engine power less than 500 hp). The engines have not been reconstructed or modified (as defined in §60.15) since June 12, 2006. **Therefore, Subpart JJJJ does not apply**.

Should BP propose to install a replacement engine for Units TS1-1, TS1-2, TS1-3, or TS1-4 that is subject to Subpart JJJJ, BP will not be allowed to use the off permit changes provision, and will be required to submit a minor permit modification application to incorporate Subpart JJJJ requirements into the permit.

40 CFR Part 60, Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005. The rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour.

According to BP, there are no stationary gas turbines located at Treating Site #1 Central Delivery Point. **Therefore, Subpart KKKK does not apply.**

40 CFR Part 60, Subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011. Affected facilities under this subpart include gas wells, compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units.

According to BP, Treating Site #1 Central Delivery Point does not have any affected facilities under the rule that commenced construction after August 23, 2011. **Therefore, Subpart OOOO does not apply**.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for HAPs that regulate specific categories of sources that emit one or more HAP regulated pollutants under the CAA. The general provisions under Subpart A apply to sources that are subject to the specific subparts of Part 63.

As explained below, Treating Site #1 Central Delivery Point is subject to the recordkeeping requirements of 40 CFR 63 Subparts HH and to the January 30, 2013 revisions to 40 CFR part 63, subpart ZZZZ. Therefore the General Provisions of Part 63 apply. Additionally, though units TS1-7b & TS1-10b are not subject to the relevant standards of their relevant source category, subpart HH, a record of an applicability determination demonstrating that the units are not subject to the relevant Part 63 standards must be kept (per § 63.10(b)(3)) at BP's Durango Operations Center for 5 years after the determinations or until a source changes its operations to become an affected source.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are area or major sources of HAPs, as defined by §63.761, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. For the purpose of this subpart, natural gas enters the transmission and storage category after the natural gas processing plant, when present. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption

Those sources whose maximum natural gas throughput, as appropriately calculated per §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day and a facility-wide actual annual average hydrocarbon liquid throughput less than 39,700 liters per day are exempt from the requirements of this subpart.

Source Aggregation

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units.

2) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination.

Facility

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in Subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGLs from field gas, or the fractionation of mixed NGLs to natural gas products, or a combination of both. A treating plant or gas plant that does not engage in these activities is considered to be a production field facility.

Major Source Determination for Production Field Facilities

The definition of major source in subpart HH (at 40 CFR 63.761) states, in part, that only emissions from the dehydration units and storage vessels at production field facilities shall be aggregated when comparing to the major source thresholds.

For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability

40 CFR Part 63, Subpart HH applies also to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for glycol dehydration units found at oil and gas production facilities based on their geographical location.

Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol recirculation pump rate optimized or operators must document that uncontrolled annual actual benzene emissions are less than 0.9 megagrams (1,984 lbs.).

Any source that determines that it is not a major source but has actual emissions of 5 tons per year of a single HAP or 12.5 tons per year of a combination of HAP (i.e. 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination and each year thereafter, using gas composition data measured during the preceding 12 months.

Applicability of Subpart HH to Treating Site #1 Central Delivery Point

According to BP, the Treating Site #1 Central Delivery Point is located prior to the point of custody transfer and is therefore considered a production field facility and not a natural gas transmission or storage facility. Potential HAP emissions from the glycol dehydration units and storage vessels at the facility are less than the major source thresholds of 25 tpy total HAPS and 10 tpy of a single HAP. Therefore, Treating Site #1 Central Delivery Point is considered an area source of HAPs according to 40 CFR Part 63, subpart HH. Uncontrolled actual average benzene emissions from each dehydration unit are less than 0.9 megagrams. Per 40 CFR 63.764(e)(1)(ii), the dehydration units are exempt from the 40 CFR 63.764(d) general standards for area sources. **Therefore, only recordkeeping requirements apply to the facility.**

40 CFR Part 63, Subpart HHH: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This subpart applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are a major source of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines are used for long distance transport (excluding processing).

According to BP, Treating Site #1 Central Delivery Point is a natural gas production facility and not a natural gas transmission or storage facility. **Therefore, Subpart HHH does not apply.**

40 CFR Part 63, Subpart ZZZZ (RICE MACT): National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary spark ignition internal combustion engines (SI ICE) and stationary compression ignition internal combustion engines (CI ICE).

For the purposes of this standard, construction or reconstruction is as defined in §63.2.

Summary of Applicability to Engines at Major HAP Sources

Major HAP Sources				
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**	
SI ICE – All1	≥ 500 hp	New	On or After:	12/19/2002
SI ICE – 4SRB	> 500 hp	Existing	Before:	12/19/2002
SI ICE – All1	≤ 500 hp	New	On or After:	6/12/2006
SI ICE - All1	≤ 500 hp	Existing	Before:	6/12/2006
CI ICE - All2	≥ 500 hp	New	On or After:	12/19/2002
CI ICE – Non Emergency	> 500 hp	Existing	Before:	12/19/2002
CI ICE – All2	≤ 500 hp	New	On or After:	6/12/2006
CI ICE – All2	≤ 500 hp	Existing	Before:	6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Summary of Applicability to Engines at Area Hap Sources

Area HAP Sources				
Engine Type	**Horse Power Rating**	**New / Existing**	**Applicability Trigger Date**	
SI ICE - All[1]	All hp	New	On or After:	6/12/2006
SI ICE - All[1]	All hp	Existing	Before:	6/12/2006

CI ICE - All[2]	All hp	New	On or After: 6/12/2006
CI ICE - All[2]	All hp	Existing	Before: 6/12/2006

1. All includes emergency ICE, limited use ICE, ICE that burn land fill or digester gas, 4SLB, 2SLB, and 4SRB.
2. All includes emergency ICE and limited use ICE

Table 5-Applicability of 40 CFR 63, Subpart ZZZZ to Treating Site #1 Central Delivery Point:

Unit	Serial Number	Unit Description	Fuel	Site Rated BHP	Commenced Construction or Reconstruction Date
TS1-1	401228	Waukesha L5790-GSI Compressor Engine	Natural Gas	1,194	Prior to 6/12/2006
TS1-2	400296	Waukesha l5790-GSI Compressor Engine	Natural Gas	1,194	Prior to 6/12/2006
TS1-3	399858	Waukesha VRG 330 Generator Engine	Natural Gas	57	Prior to 6/12/2006
TS1-4	5299365	Waukesha F11-G	Natural Gas	97	Prior to 6/12/2006

According to BP Treating Site #1 CDP is an area source of HAPs as defined in this subpart. All currently permitted engines at the facility commenced construction or reconstruction prior to June 12, 2006 and are therefore considered existing stationary RICE for this subpart. On January 30, 2013, the Environmental Protection Agency (EPA) published additional amendments to this subpart, which outline requirements for a new subcategory of "Remote Stationary RICE" located at area sources of HAPs, as defined by 40 CFR 63.6675. According to BP units TS1-1 and TS2-2 qualify as existing 4SRB remote stationary RICE greater than 500 site-rated horsepower located at an area source of HAPs, have an initial compliance date of October 19, 2013, and must re-evaluate the remote status of their stationary RICE every 12 months, per 40 CFR 63.6603(f). Units TS1-3 and TS1-4 are existing 4SRB engines less than or equal to 500 site-rated horsepower located at an area source of HAPs and have an initial compliance date of October 19, 2013. **Therefore, units TS1-1, TS1-2, TS1-3, and TS1-4 are subject to the applicable requirements for area sources found in 40 CFR Part 63, Subpart ZZZZ.** As required by 40 CFR 63.6603 for existing SI RICE located at an area source of HAPs, emissions units TS1-1, TS1-2, TS1-3, and TS1-4 must comply with the applicable work, operation and management practices outlined in Table 2d and Table 6 of Subpart ZZZZ.

40 CFR Part 63, Subpart DDDDD (Boiler MACT): National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. This rule establishes national emission limitations and work practice standards for HAPs emitted from new and existing industrial boilers, institutional boilers, commercial boilers, and process heaters that are located at major sources of HAPs, as defined by 40 CFR 63.7575. Boilers or process heaters that combust natural gas for fuel or have a maximum designed heat input capacity less than 10 MMBtu/hr are subject to work practice standards in lieu of emission limits For the purposes of this subpart, an affected unit is an existing unit if it was constructed prior to June 4, 2010.

According to BP the Treating Site #1 Central Delivery Point is a pipeline compressor station located prior to the point of custody transfer, and is a production field facility. The definition of a major source for oil and natural gas production facilities at 40 CFR 63.7575(1)-(3) allows only the aggregation of HAP emissions from the glycol dehydration units and storage vessels with the potential for flash emissions at the facility for the major source determination. Based on this major source determination the facility HAP emissions are below the major source thresholds. **Therefore, Subpart DDDDD does not apply.**

40 CFR Part 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers. This rule establishes national emission standards and operating limitations for HAPs emitted from new and existing industrial boilers, institutional boilers, and commercial boilers, as defined in § 63.11237, and are located at area sources of HAPs, as defined in § 63.2, except as specified in § 63.11195. For the purposes of this subpart, an affected unit is an existing unit if it was constructed prior to June 4, 2010.

According to BP, no equipment at Treating Site #1 Central Delivery Point meets the definition of a boiler as defined in § 63.11237, **Therefore, Subpart JJJJJJ does not apply.**

Compliance Assurance Monitoring (CAM) Rule

40 CFR Part 64: Compliance Assurance Monitoring Provisions. According to 40 CFR 64.2(a), the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) at a major source that is required to obtain a Part 70 or Part 71 permit if the unit satisfies all of the following criteria:

1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant other than an emissions limitation or standard that is exempt under §64.2(b)(1);

"§64.2(b)(1): Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:

(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to Section 111 or 112 of the Act;
(ii) Stratospheric ozone protection requirements under Title VI of the Act;
(iii) Acid Rain Program requirements pursuant to Sections 404, 405, 406, 407(a), 407(b) or 410 of the Act;
(iv) Emissions limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions with a source or between sources;
(v) An emissions cap that meets the requirements specified in §70.4(b)(12) or §71.6(a)(13)(iii) of this chapter;
(vi) Emission limitations or standards for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1."

"§64.1: Continuous compliance method means a method, specified by the applicable standard or an applicable permit condition, which:

(1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and
(2) Provides data either in units of the standard or correlated directly with the compliance limit.”

2) The unit uses a control device to achieve compliance with any such limit or standard; and

3) The unit has pre-control device emissions of the applicable regulated pollutant that are equal to or greater than 100% of the amount, in tons per year, required for a source to be classified as a major source.

According to BP, Treating Site #1 Central Delivery Point is a major source of NO_x and CO. Emission units TS1-1 and TS1-2 are both PSEUs with pre-controlled emissions that equal or exceed 100% of NO_x and CO thresholds and use a control device to comply with an emission limitation**. Therefore, units TS1-1 and TS1-2 are subject to CAM requirements**

Chemical Accident Prevention Program

40 CFR Part 68: Chemical Accident Prevention Provisions. This rule applies to stationary sources that manufacture, process, use, store, or otherwise handle more than the threshold quantity of a regulated substance in a process. Regulated substances include 77 toxic and 63 flammable substances which are potentially present in the natural gas stream entering the facility and in the storage vessels located at the facility. The quantity of a regulated substance in a process is determined according to the procedures presented under §68.115. The regulations at §68.115(b)(l) and (2)(i) indicate that toxic and flammable substances in a mixture do not need to be considered when determining whether more than a threshold quantity is present at a stationary source if the concentration of the substance is below one percent by weight of the mixture. The regulations at §68.115(b)(2)(iii) indicates that prior to entry into a natural gas processing plant, regulated substances in naturally occurring hydrocarbon mixtures need not be considered when determining whether more than a threshold quantity is present at a stationary source. Naturally occurring hydrocarbon mixtures include condensate, field gas, and produced water.

Based on BP’s application, Treating Site #1 Central Delivery Point does not have regulated substances above the threshold quantities in this rule. **Therefore the facility is not subject to the requirement to develop and submit a risk management plan.**

Stratospheric Ozone and Climate Protection

40 CFR Part 82, Subpart F: Air Conditioning Units. According to BP, there are no air conditioning units at the Treating Site #1 Central Delivery Point that contain Class I or Class II refrigerants (chlorofluorocarbons (CFCs)). However, should BP obtain any air conditioning units at the Treating Site #1 Central Delivery Point that contain Class I or Class II refrigerants then it must comply with the standards of part 82 subpart F for recycling and emissions reduction if they service, maintain, or repair the air conditioning units in any way or if they dispose of the units.

40 CFR Part 82, Subpart H: Halon Fire Extinguishers. According to BP, there are no halon fire extinguishers at Treating Site #1 Central Delivery Point. However, should BP obtain any halon fire extinguishers, then it must comply with the standards of 40 CFR Part 82, Subpart H for halon emissions reduction, if it services, maintains, tests, repairs, or disposes of equipment that contains halon or uses such equipment during technician training. Specifically, BP would be required to comply with 40 CFR Part 82 and submit an application for a revision to this Title V permit.

Mandatory Greenhouse Gas Reporting

40 CFR Part 98: Mandatory Greenhouse Gas Reporting. This rule requires sources above certain emission thresholds to calculate, monitor, and report greenhouse gas emissions. The requirements of 40 CFR Part 98 and CAA §307(d)(1)(V), the CAA authority under which 40 CFR Part 98 was promulgated, however, need not be included in a part 70 permit because those requirements are not included in the definition of "applicable requirement" in either 40 CFR part 70 or RAC 1-103(11). Although the rule is not an applicable requirement under 40 CFR Part 70 or the RAC, the source is not relieved from the requirement to comply with the rule separately from compliance with its Part 70 operating permit. It is the responsibility of each source to determine whether Part 98 is applicable and to comply, if necessary.

3. Tribal Authority

Reservation Air Code: The Reservation Air Code was adopted pursuant to the authority vested in the Southern Ute Indian Tribe/State of Colorado Environmental Commission by (1) the Intergovernmental Agreement Between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian Reservation dated December 13, 1999, (2) tribal law (Resolution of the Council of the Southern Ute Indian Tribe # 00-09), (3) State law (C.R.S. § 24- 62-101), and (4) as recognized in federal law (Act of October 18, 2004, Pub. L. No. 108-336, 118 Stat.1354).

Title V Permitting Program: On March 2, 2012, the EPA determined that the Southern Ute Indian Tribe of the Southern Ute Indian Reservation had met the requirements of 40 CFR § 70.4(b) for full approval to administer its Clean Air Act Title V, Part 70 Permitting Program (Program). In concert with that Program approval, the EPA also found that the Tribe met the requirements of Section 301(d)(2) of the CAA and 40 CFR § 49.6 for treatment "in the same manner as a state" for the purposes of issuing CAA Title V, Part 70 operating permits. The EPA promulgated its approval of the Tribe's applications on March 15, 2012 (77 FR 15267).

NSPS and NESHAP Delegation: On September 6, 2013, the Southern Ute Indian Tribe received delegation from the EPA to incorporate by reference into the Reservation Air Code and enforce certain subparts of the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) under Sections 111 and 112 of the Clean Air Act, respectively (78 FR 40635). These NSPS and NESHAP subparts generally apply to oil and gas operations within the exterior boundaries of the Southern Ute Indian Reservation and were adopted unchanged into the Reservation Air Code as Parts 2 and 3.

Southern Ute Indian Tribe Minor Source Program: The Southern Ute Indian Tribe/State of Colorado Environmental Commission is currently developing a Minor Source Program in order to fill a regulatory gap wherein sources of air pollution located on the Reservation have been subject to fewer requirements than similar sources located on land under the jurisdiction of a state air pollution control agency. Until such time EPA approves the Minor Source Program as part of a TIP under the Tribal Authority Rule affected sources must comply with the federal rule "Review of New Sources and Modifications in Indian country" that was published on July 1, 2011. This rule requires new and existing synthetic minor sources currently operating under federal operating permits for sources in Indian Country (regulated at 40 CFR Part 71), as well as sources proposing minor modifications at existing major sources, to submit applications to the region starting August 30, 2011.

Implementation Plans: Since Treating Site #1 Central Delivery Point is located in Indian Country, the State of Colorado's implementation plan does not apply to this source. In addition, no tribal implementation plan (TIP) has been submitted and approved for the Southern Ute Indian Tribe, and EPA has not promulgated a federal implementation plan (FIP) for the area of jurisdiction governing the Southern Ute Indian Reservation. Therefore, Treating Site #1 Central Delivery Point is not subject to any implementation plan.

4. Public Participation

a. Public Notice

Per RAC § 2-109, all Part 70 draft operating permits shall be publicly noticed and made available for public comment. Public notice is given by publication in a newspaper of general circulation in the area where the source is located or in a state publication designed to give general public notice, to persons on a mailing list developed by the Tribe, including those who request in writing to be on the list, and by other means if necessary to assure adequate notice to the affected public. If an interested person would like to be added to the Tribe's mailing list to be informed of future actions on permits issued by the Tribe, please send your name and address:

by United State Postal Service to:

Southern Ute Indian Tribe
Environmental Programs Division
Part 70 Program
PO Box 737 MS #84
Ignacio, Colorado 81137

by any other delivery service to:

Southern Ute Indian Tribe
Environmental Programs Division
Part 70 Program
398 Ouray Drive
Ignacio, Colorado 81137

Public notice for the draft permit was published in the Durango Herald, on September 9, 2013 in order to provide opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for Comment

Members of the public were given an opportunity to review a copy of the draft permit prepared by the Tribe, the application, the statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents were available at:

Southern Ute Indian Tribe
Environmental Programs Division
Air Quality Program
71 Mike Frost Way
Ignacio, Colorado 81137

All documents were available for review at the Southern Ute Indian Tribe's Environmental Programs Division office Monday through Friday from 9:00 a.m. to 4:00 p.m. (excluding holidays).

Any interested person was given the opportunity to submit written comments on the draft Part 70 operating permit during the public comment period. The Tribe has considered and addressed all comments in making a final decision on the permit. The Tribe keeps a record of the commenters and of the issues raised during the public participation process.

Anyone, including the applicant, who believed any condition of the draft permit is inappropriate could raise all reasonably ascertainable issues and submit all arguments supporting his or her position by the close of the public comment period. Any supporting materials submitted must have been included in full and may not have been incorporated by reference, unless the material had already been submitted as part of the administrative record in the same proceeding or consisted of Environmental Commission, tribal, state or Federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to the Part 70 Permit Contact, at the addresses listed above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, the Tribe will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. The Tribe will provide public notice of the public hearing. If a public hearing is held, any person may submit oral or written statements and data concerning the draft permit.

d. Public Petitions to the Administrator

In the event the Administrator of the United States Environmental Protection Agency does not object to issuance of the permit, on the basis that it would not be in compliance with applicable requirements, within its 45-day review period, any person may then petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection. Any such petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objections arose after such period. If the Administrator objects to a permit as a result of this petition, the Tribe shall not issue the permit until the Administrator's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day review period and before the Administrator's objection.

e. Appeal of Permits

Within 60 days after the Tribe's final permit action, an applicant, any person who filed comments on the draft permit or participated in the public hearing, and any other person who could obtain judicial review of that action under applicable law, may appeal to the Environmental Commission in accordance with RAC 2-109(8) and the Commission's Procedural Rules.

Petitions for administrative review of final permit actions can be filed after the deadline designated by the Commission only if they are based solely on grounds arising after the deadline for administrative review. Such petitions shall be filed no later than 60 days after the new grounds for review arise. If the final permit action being challenged is the Tribe's failure to take final action, a petition for administrative review may be filed any time before the Tribe denies or issues the final permit.

f. Notice to Affected States/Tribes

As described in RAC § 2-109(3), public notice will be given by notifying all affected programs. The following entities will be notified:

- State of Colorado, Department of Public Health and Environment
- State of New Mexico, Environment Department
- Ute Mountain Ute Tribe, Environmental Programs Department
- Navajo Tribe, Navajo Nation EPA
- Jicarilla Tribe, Environmental Protection Office
- National Park Service, Air Resources Division, Denver, CO
- U.S. Department of Agriculture, United States Forest Service, Rocky Mountain Region