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

January 31, 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-0038-2014.00
BP America Production Company
Dry Creek 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 Dry Creek 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 March 12, 2014.

A 30-day public comment period was held from October 4, 2013 to November 4, 2013. The Tribe received comments from Rebecca Robert, Air Specialist for BP on October 31, 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 made 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

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

- Text revised to better align with the Reservation Air Code (RAC).

A 45-day Administrative Review period at EPA Region 8 was held from December 6, 2013 to January 20, 2014. No comments were received from EPA during this review period.

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-0038-2014.00 and associated Statement of Basis for the Dry Creek 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, Pages 4-5, I.A. Source Information

A. On page 4, BP requests to update the following language in the section titled "Other Clean Air Act Permits:" "This permit replaces the facility's EPA-issued part 71 permit (V-SU-*0*038-08.00). There are no other CAA permits issued to this facility*.* ~~Title V Operating Permit: Title V Operating Permit:~~"

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

B. On page 5, BP requests to correct the last paragraph of the "Description of Process" as follows: "…The four engines are four-stroke lean-burn (4SLB) spark ignition (SI) Waukesha 7042 GL reciprocating internal combustion engines (RICE) ~~engines~~ fueled by natural gas. Insignificant emission sources ~~including~~ *include* several small storage tanks (~~<~~ *≤* 500 gal), two 210 bbl produced water tanks, *one 95 bbl used oil sump tank,* one 95 bbl water and oil sump tank, one 95 bbl residual TEG tank…"

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

2. Permit, Page 5, I.B. Source Emission Points, Table 1

A. BP requests to update the horsepower listed for Emission Unit IDs C-100, C-200, C-300 and C-400 to reflect the ~~1,478~~ *1,318 site-rated* horsepower, rather than the nameplate horsepower rating. The potential to emit calculations submitted in the application are based on the site-rated horsepower for each engine. Alternatively, BP suggests that Table 1 clarify that the 1,478 horsepower listed is the nameplate horsepower rating to reduce any future confusion.

Tribe's Response: The suggested change has not been made. The Tribe would prefer to use the nameplate rated horsepower in Table 1. However, the tribe will clarify that this is the nameplate horsepower rating for the engines.

B. In Table 1, BP requests to correct the control equipment description from "~~Air to fuel ratio controller~~" to "*None*" for C-100, C-200, and C-300. In Section D of the EUD Forms submitted for these units in the November 2011 permit application, both "N/A" and "Air/Fuel Ratio Controller" were selected as associated air pollution control equipment;

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

however, C-100, C-200, and C-300 do not have air to fuel ratio controller equipment. Please advise if the Tribe will require updated EUD forms to be submitted for these units.

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

3. Permit, Page 6, Section II. Requirements for Engines

A. BP requests to add the following language to this section: "Emission units C-100, C-200, C-300, and C-400 are stationary RICE greater than 500 site-rated brake horsepower constructed prior to December 19, 2002 *and have not been reconstructed since this date*. Therefore, all four units are considered existing stationary RICE *under 40 CFR Part 63, subpart ZZZZ*…"

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

4. Permit, Pages 6-9, Section III. Facility-Wide Requirements

A. On page 6, BP requests to include "*RAC 4-103*" as a regulatory reference for Section III.A. General Recordkeeping Requirements since BP has recordkeeping requirements under 40 CFR 63, Subparts A and HH.

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

B. On pages 7-8, BP requests to delete Section III.B. General Reporting Requirements from the permit and renumber the remainder of the permit. This section is requiring the submittal of semi-annual monitoring reports and prompt deviation reports; however, the emission units at the Dry Creek CDP do not have monitoring requirements or emission limitations. Therefore, semi-annual monitoring reports and prompt deviation reports should not be required.

Tribe's Response: The requested change has not been made. The Tribe prefers to keep the General Reporting Requirements section as a placeholder in every permit, regardless of whether or not the facility has reporting requirements, and because this section acts as a catch-all for all of the potentially applicable reporting requirements for a Title V facility. The Tribe also prefers to have the General Reporting Requirements section included in the permit to reduce the required revisions to the permit in the event that the facility becomes subject to any reporting requirements.

C. On page 8, in section III.C. Alternative Operating Scenarios, BP requests to delete "…~~or a Significant Permit Revision as specified in RAC 2-111(4)…~~" as an option for incorporating any new applicable requirements resulting from the replacement of an existing engine. BP believes the minor permit revision procedures are adequate procedures to incorporate new applicable requirements triggered by an engine replacement.

Tribe's Response: The requested change has not been made. The Tribe believes that a replacement engine not meeting the requirements of the alternative operating scenario provisions could potentially fall within the definition of a significant permit revision per RAC 1-103(61)(b).

D. On page 9, in Condition III.C.2., BP requests clarification from the Tribe regarding the timing of the written notice required for engine replacements made under Section III.C. Alternative Operating Scenarios. Condition III.C.2. requires "contemporaneous" notifications. However, this Condition later states that the notice shall state when the exchange "occurred," implying the notice is required after the replacement. Please clarify.

Tribe's Response: Written notice of any replacement of an existing engine must be provided to both the Tribe and the Administrator contemporaneously. This required notice can be submitted after the replacement as long as the alternative operating scenario requirements are met.

5. Permit, Pages 9-19, Section IV. Part 70 Administrative Requirements

A. On page 12, 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 requested change has been made.

B. On page 14, 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, ~~The~~ 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 requested changes have been made.

C. On page 17, in Condition IV.O.1(d), BP requests clarification from the Tribe regarding the timing of the written notice required for Off Permit Changes. Condition IV.O.1(d) requires "contemporaneous" notifications. However, this Condition later states that the notice shall state when the exchange "occurred," implying the notice is required after the change is made. Please clarify.

Tribe's Response: Written notice of any off permit change must be provided to both the Tribe and the Administrator contemporaneously. This notice can be submitted after the change is made *as long as the change meets the requirements for off permit changes.*

6. Statement of Basis, Section 1, Facility Information

A. On page 1, in Section 1.a, BP requests to change the location of the site to "SW¼ ~~NW¼~~ Section 5U, T34N, R7W."

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

B. In Section 1.c, BP requests to correct the last paragraph of the "Description of Operations" as follows: "…The four engines are four-stroke lean-burn (4SLB) spark ignition (SI) Waukesha 7042 GL reciprocating internal combustion engines (RICE) ~~engines~~ fueled by natural gas. Insignificant emission sources ~~including~~ *include* several small storage tanks (~~<~~ ≤ 500 gal), two 210 bbl produced water tanks, *one 95 bbl used oil sump tank*, one 95 bbl water and oil sump tank, one 95 bbl residual TEG tank…"

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

C. In Table 1 – Emission Units, BP requests to update the horsepower listed for Emission Unit IDs C-100, C-200, C-300, and C-400 to reflect the ~~1,478~~ *1,318 site-rated* horsepower, rather than the nameplate horsepower rating. The potential to emit calculations submitted in the application are based on the site-rated horsepower for each engine. Alternatively, BP suggests that Table 1 clarify that the 1,478 horsepower listed is the nameplate horsepower rating to reduce and future confusion.

Tribe's Response: The suggested change has not been made. The Tribe would prefer to use the nameplate rated horsepower in Table 1. However, the tribe will clarify that this is the nameplate horsepower rating for the engines.

D. In Table 1, BP requests to correct the control equipment description from "~~Air to fuel ratio controller~~" to "*None*" for C-100, C-200, and C-300. In Section D of the EUD Forms submitted for these units in the November 2011 permit application, both "N/A" and "Air/Fuel Ration Controller" were selected as associated air pollution control equipment; however, C-100, C-200, and C-300 do not have air to fuel ratio controller equipment. Please advise if the Tribe will require updated EUD forms to be submitted for these units.

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

E. In Table 1 – Emission units, BP requests to add "unenforceable)" to the Control Equipment description for Emission Unit ID C-400.

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

7. Statement of Basis, Section 3, Applicable Requirements

A. In Table 3 of the 40 CFR Part 60, Subpart JJJJ applicability determination and in the applicability table for 40 CFR Part 63, Subpart ZZZZ, BP requests to correct the serial number for Unit C-300 to "C-11100/~~0~~7."

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

B. In the applicability determination for 40 CFR Part 60, Subpart OOOO, BP requests to change the following sentence: "According to BP, Dry Creek CDP is not a *natural gas processing plant or a gas well, nor does a gas well exist at the site*. ~~Crude oil or natural gas production site or a natural gas processing plant.~~"

Tribe's Response: The requested change 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-0038-2014.00
January 31, 2014

BP America Production Company
Dry Creek Central Delivery Point
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

The Dry Creek 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 SW¼ Section 5U, T34N, R7W, in La Plata County, at latitude North 37.213598 and longitude West -107.640711. The mailing address is:

BP America Production Company
Dry Creek Central Delivery Point
380A Airport Road
Durango, CO 81303

b. Contacts

Facility Contact:	**Responsible Official:**
Julie Best Environmental Advisor BP America Production Company 380A Airport Road Durango, CO 81303 970-375-7540	Stephen Collins Onshore Site Manager – San Juan North BP America Production Company 380A Airport Road Durango, CO 81303 970-247-6810
Alternate Responsible Official:	**Alternate Responsible Official:**
Jerry Austin Area Operations Manager BP America Production Company 501 Westlake Park Boulevard Houston, TX 77079 281-366-2953	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

Dry Creek Central Delivery Point (Dry Creek CDP) is a natural gas compression facility located in southwestern Colorado within the exterior boundaries of the Southern Ute Indian Reservation. The facility compresses coal bed methane gas from wells in the Fruitland formation. Dry Creek CDP does not handle any condensate or natural gas liquids.

Natural gas entering the compressor station first passes through an inlet separator vessel to remove any free liquids in the gas stream by gravity. The gas then passes to a filter vessel at the inlet to each compressor, which serves to filter out any solids such as coal dust in the gas. The gas stream then passes to a distribution header, which distributes gas to one of four compressors.

After compression the gas passes through an outlet coalescer vessel, which serves to remove any entrained droplets of lubricating oil carried over from the compressors. The gas then passes to one of three glycol absorber columns where it contacts a TEG solution. The purpose of this contact is to remove water vapor in the gas. The gas is then routed and metered into the medium pressure pipeline.

The pigging and pipeline clean-out system at Dry Creek CDP consists of one pig launcher and two pig receivers. The pigging operation is not a closed loop system; therefore, venting emissions are associated with the process. Calculations are included in the application and are based on the assumption that each pig is used twenty (20) times per year.

The primary emission units at Dry Creek CDP include four skid-mounted combinations of engine and compressor units and three tri-ethylene glycol (TEG) dehydrator/regenerator units. The four engines are four-stroke lean-burn (4SLB) spark ignition (SI) Waukesha 7042 GL reciprocating internal combustion engines (RICE) fueled by natural gas. Insignificant emission sources include several small storage tanks (< 500 gal), two 210 bbl produced water tanks, one 95 bbl used oil sump tank, one 95 bbl water and oil sump tank, one 95 bbl residual TEG tank, natural gas-fired combustion units including tank heaters and reboilers, process fugitives, and venting emissions from pigging operations.

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, Dry Creek Central Delivery Point

Emission Unit ID	Description	Control Equipment
C-100 C-200 C-300	3 - Waukesha L7042GL (4SLB SI) Compressor Engines, 1,478 nameplate rated hp each Serial No.: C-11492-2 Installed: 07/2010 Serial No.: 365279 Installed: 05/2011 Serial No.: C-11100/7 Installed: 04/2011	None
C-400	1 - Waukesha L7042GL (4SLB SI) Compressor Engine, 1,478 nameplate rated hp Serial No.: 403605 Installed: 04/2012	Air to fuel ratio controller and oxidation catalyst (unenforceable)
Dehy1 Dehy2 Dehy3	3 –Tri-ethylene Glycol (TEG) Dehydrator Regenerators and Flash Tank Vents, 20 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 deminimis 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 the emission units in Table 2, below, are insignificant. BP provided emission estimates and example calculations for each storage tank using EPA Tanks 4.0.9d, combustion units using emission factors from AP-42, Table 1.4-2, and process fugitive emissions using emission factors from the EPA's *Protocol for Equipment Leak Emission Estimates, Table 2-4* (November 1995). This data supports the source's claim that these units qualify as insignificant.

Table 2 – Insignificant Emission Units
BP America Production Company, Dry Creek Central Delivery Point

Emission Unit ID	Description
N/A	1 - 95 bbl Used Oil Sump Tank
N/A	4 - 500 gal Lube Oil Tanks
N/A	2 - 300 gal Tri-ethylene Glycol (TEG) Storage Tanks
N/A	1 - 500 gal Tri-ethylene Glycol (TEG) Storage Tank
N/A	1 - 500 gal Ethylene Glycol (EG) Storage Tank
N/A	2 - 210 bbl Produced Water Tanks

N/A	2 - 250 MBtu/hr Tank Heaters
N/A	1 - 95 bbl Water and Oil Sump
N/A	1 - 500 MBtu/hr Tri-ethylene Glycol (TEG) Dehy Unit Reboiler
N/A	1 - 750 MBtu/hr Tri-ethylene Glycol (TEG) Dehy Unit Reboiler
N/A	1 - 800 MBtu/hr Tri-ethylene Glycol (TEG) Dehy Unit Reboiler
N/A	1 - 95 bbl Residual Tri-ethylene Glycol (TEG) Sump Tank
N/A	Process fugitive emissions – (Estimated 411 subject components)
N/A	Pigging Operations (approximately 30 Mscf/yr)

e. Facility Construction and Permitting History

Dry Creek CDP commenced operation February 2000 as a minor Title V stationary source. The EPA issued the initial part 71 permit (No. V-SU-0038-03.00) in January 2004. This permit has undergone six revisions since initial issuance including five administrative amendments and one minor modification. The permit was renewed in October 2009 and the current authorization is V-SU-0038-08.00. The referenced permit will be replaced by Part 70 Permit No. V-SUIT-0038-2014.00.

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 Dry Creek CDP was listed by BP in Forms "GIS", "PTE", and the various forms "EMISS" of the Part 70 operating permit initial application. T able 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, Dry Creek Central Delivery Point

Emission Unit ID	Regulated Air Pollutants in tpy								
	NO_x [1]	VOC [2,6]	SO_2 [3]	PM_{10} [3]	CO [4]	Lead	Total HAPs	Largest [5] Single HAP (CH_2O)	GHGs (CO_2 *e* tpy)
C-100	19.1	12.7	0.0	0.4	38.2		3.7	3.7	4,832.8
C-200	19.1	12.7	0.0	0.4	38.2		3.7	3.7	4,832.8
C-300	19.1	12.7	0.0	0.4	38.2		3.7	3.7	4,832.8
C-400	20.4	12.7	0.0	0.4	38.2		3.7	3.7	4,832.8
Dehy1	0.0	33.2	0.0	0.0	0.0		0.0	0.0	1,905.2
Dehy2	0.0	33.2	0.0	0.0	0.0		0.0	0.0	1,905.2
Dehy3	0.0	17.7	0.0	0.0	0.0		0.0	0.0	4,151.4
Total IEUs	1.4	0.1	0.0	0.1	1.2		0.0	0.0	22,868.3
TOTAL	**79.0**	**135.0**	**0.1**	**1.8**	**153.9**		**14.8**	**14.8**	**50,161.3**

[1] *Engine uncontrolled NO_x emission estimates are based on Waukesha Bulletin 7005 0102 for L7042GL VHP Series engine (SI 4SLB RICE) using 1,478 hp and associated 7,155 Btu/hp-hr.*
[2] *Engine units uncontrolled VOC emission estimates are based on Waukesha Gas Engine Exhaust Emission Levels, dated 03/2011, pages 3 and 8 VHP Emission Levels GL. Total VOC emission factor conservative at 1.0 g/hp-hr.*
[3] *Engine SO_2 and PM_{10} emissions estimates are based on AP-42, Fifth Edition, Volume 1, Chapter 3, Section 3.2, Table 3.2-2 Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines.*
[4] *Engine uncontrolled CO emission estimates are based on Waukesha Bulletin 7005 0102 for low fuel consumption setting. Calculations use 3.0 g/hp-hr CO emission factor.*
[5] *Engine uncontrolled organic Hazardous Air Pollutant (HAP) emission estimates (as CH_2O) are based on Waukesha Gas Engine Exhaust Emission Levels, dated 03/2011, pages 3 and 8 VHP Emission Levels GL. Calculations use 0.29 g/hp-hr CH_2O emission factor.*
[6] *Uncontrolled dehydrator emissions are based on GRI GLY-Calc Version 4.0 modeled emissions.*
[7] *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. Tribal Authority

BP's Dry Creek CDP is located within the exterior boundaries of the Southern Ute Indian Reservation and is thus within Indian Country as defined at 18 U.S.C. §1151. 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). The requirements of the Clean Air Act Title V, Part 70 Permitting Program (Program) have been incorporated at Article II, Part 1 of the Reservation Air Code. Therefore, the Southern Ute Indian Tribe is the appropriate governmental entity to issue the Title V permit to this facility.

The 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 No. 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).

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 that 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 (76 FR 38748). 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 EPA starting August 30, 2011. Existing true minor sources are required to register with the permitting authority no later than March 1, 2013.

3. Applicable Requirements

The following discussion addresses a selection of the regulations from the Code of Federal Regulations (CFR) at Title 40. 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. The following discussion does not include all potentially applicable regulations and is not intended to represent official Tribe applicability determinations.

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 considered a major stationary source or a major modification of an existing stationary source as defined in 40 CFR §52.21 (b)(1)(i) and (b)(2)(i). A new stationary source or a modification to an existing stationary source is major if the proposed project has the PTE any pollutant regulated under the CAA in amounts equal to or exceeding specified major source thresholds, which are 100 tpy for 28 listed industrial sources (named source) and 250 tpy for all other sources. 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 (b)(23). A modification is a physical change or change in the method of operation.

Dry Creek CDP is not a PSD named source. Therefore, the PTE threshold for determining PSD applicability for this source is 250 tpy for criteria pollutants and 100,000 tpy for CO_2e. The PTE of regulated pollutants at this facility are currently below major source thresholds, therefore, this site is not subject to the requirements of PSD.

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, Dry Creek CDP 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, Dry Creek CDP 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, Dry Creek CDP 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, Dry Creek CDP 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, Dry Creek CDP 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 (472 bbl).

According to BP, All tanks storing volatile organic liquids at Dry Creek CDP are less than 75 m^3 (472 bbl 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 Dry Creek CDP. **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, Dry Creek CDP 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, Dry Creek CDP does not perform gas sweetening or 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 Dry Creek CDP. **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 3 - NSPS Subpart JJJJ Applicability Determination
BP America Production Company, Dry Creek Central Delivery Point

Unit[1]	Serial No	Unit Description	Fuel	BHP[2]	Manufacture Date	Commenced Construction Date	Subpart JJJJ Trigger Date - Manufactured on or after
C-100	C-11492-2	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,478	01/31/1995	Prior to 6/12/2006	7/1/2007
C-200	365279	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,478	09/09/1981	Prior to 6/12/2006	7/1/2007
C-300	11100/7	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,478	04/01/1994	Prior to 6/12/2006	7/1/2007
C-400	403605	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,478	06/12/1991	Prior to 6/12/2006	7/1/2007

1. Per BP, these engines have not been modified or reconstructed since June 12, 2006 (as defined in Part 60).
2. Horsepower given is name plate rating. Site hp has been de-rated to 1,318 hp based on altitude.

According to BP, emission units C-100, C-200, C-300 and C-400 were manufactured prior to July 1, 2007 (trigger date for engines with a maximum engine power greater than or equal to 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 replacement engines for emission units C-100, C-200, C-300 and C-400 that are 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 Dry Creek CDP. **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, Dry Creek CDP is not a natural gas processing plant or a gas well, nor does a gas well exist at the site. The facility has no centrifugal compressors and there are no continuous bleed natural gas driven pneumatic controllers constructed, reconstructed or modified after October 15, 2013 . The storage vessels and four reciprocating compressors located at the site were constructed prior to August 23, 2011 and have not been modified or reconstructed since this date. **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, Dry Creek CDP is not subject to a specific Subpart of Part 63. Emission units Dehy1, Dehy2, and Dehy3 are not subject to the general standards for area sources outlined in subpart HH. However, a record of an applicability determination demonstrating the emission 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 determination 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. The affected units are glycol dehydration units, storage vessels 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.

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.

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.

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 Dry Creek CDP

> According to BP, the Dry Creek CDP 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, Dry Creek CDP is considered an area source of HAPs according to 40 CFR Part 63, subpart HH. Uncontrolled actual benzene emissions from the dehydration units at the facility 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.**

<u>40 CFR Part 63, Subpart HHH</u>: 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, Dry Creek CDP 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

Applicability of 40 CFR 63, Subpart ZZZZ to Dry Creek Central Delivery Point:

Unit	Serial Number	Unit Description	Fuel	Site Rated BHP	Commenced Construction, Reconstruction, or Modification Date
C-100	C-11492-2	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,318	Prior to 12/19/2002
C-200	365279	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,318	Prior to 12/19/2002
C-300	11100/7	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,318	Prior to 12/19/2002
C-400	403605	Waukesha L7042GL (4SLB SI) Compressor Engine	Natural Gas	1,318	Prior to 12/19/2002

According to BP, the Dry Creek CDP is a major source of HAPs as defined in subpart ZZZZ. Emission units C-100, C-200, C-300 and C-400 are each four-stroke lean burn stationary spark ignition RICE > 500 site rated horsepower constructed prior to December 19, 2002 but have not been reconstructed or modified since that date. **Therefore, C-100, C-200, C-300, and C-400 are considered existing stationary SI RICE and are not subject to the applicable requirements for a major source under 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. 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, Dry Creek CDP is a natural gas production field facility located prior to the point of custody transfer. 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 Dry Creek CDP meets the definition of a boiler as defined in §63.11237, **Therefore, 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: <u>Continuous compliance method</u> 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, there are no emission units with pre-control emissions that exceed a major source threshold. **Therefore, CAM does not apply.**

Chemical Accident Prevention Program

<u>40 CFR Part 68</u>: 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, Dry Creek CDP 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 Dry Creek CDP that contain Class I or Class II refrigerants (chlorofluorocarbons (CFCs)). However, should BP obtain any air conditioning units at the Dry Creek CDP 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 Dry Creek CDP. 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 modification 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.

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 for the draft permit was published in the Durango Herald, on October 4, 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 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 was 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 has passed. 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