

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0137
Expires: March 31, 2007

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE- Other instructions on reverse side.

1. Type of Well
☐ Oil Well ☒ Gas Well ☐ Other

2. Name of Operator **Burlington Resources Oil & Gas Company**

3a. Address
P. O. Box 4289, Farmington, NM 87499

3b. Phone No. (include area code)
505-326-9700

4. Location of Well (Footage, Sec., T., R., M., or Survey Description)

**NENW, Lot C, Sec 28-32N-14W
1120' FNL & 1860' FWL**

5. Lease Serial No.
I22IND2772

6. If Indian, Allottee or Tribe Name
Ute Mountain Ute

7. If Unit or CA/Agreement, Name and/or No.

8. Well Name and No.
Ute Mountain Ute 75

9. API Well No.
30-045-33300

10. Field and Pool, or Exploratory Area
Basin Dakota

11. County or Parish, State
San Juan Co., NM

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water Shut-Off
☒ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other Calibrated Gauge
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recompleat horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports must be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompleat in a new interval, a Form 3160-4 must be filed once testing has been completed. Final Abandonment Notices must be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

Burlington Resources Oil and Gas Company respectfully requests the use of Electronic Flow Meter (EFM) in place of chart meters for the above referenced well.

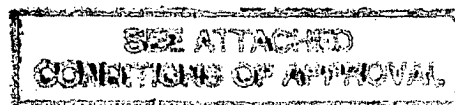
February 21, 2006:

Installed Calibrated Gauge on bradenhead valve. Gauge showed 0 psi.

RECEIVED

MAR 9 2006

**Bureau of Land Management
Durango, Colorado**



14. I hereby certify that the foregoing is true and correct
Name (Printed/Typed)

Catherine Smith

Title **Huntington Energy, L.L.C., Agent for Burlington Resources**

Signature

Catherine Smith

Date

03/06/2006

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Title

Amurs

Date

4/19/06

Office

S. J. P.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on page 2)

RECEIVED

Conditions of Approval for Electronic Flow Meters or Electronic Flow Computers.

Standards for the Use of Electronic Flow Computers Used On Differential Type Flow Meters For Gas Measurement

This notice is to inform Federal and Indian lessees/operators of the minimum standards for sales and allocation Electronic Flow Computers (EFCs) used on differential-type flow meters for gas measurement. EFCs that meet these requirements are approved for use on all Federal and Indian oil and gas leases located within New Mexico, Kansas, Oklahoma, and Texas.

For the purpose of this NTL, a "*differential-type flow meter*" is a meter that determines flow rate as a function of a change in gas pressure caused by the meter geometry. Examples include orifice plate meters, venturi meters, and pitot tubes. An "*electronic flow computer*" includes the secondary device that electronically measures the differential pressure and other variables, and the tertiary device which makes flow rate calculations, and stores the data taken.

The requirements of this NTL supercede and replace all existing local NTLs and variances addressing EFC installation and approval. (Note: NTL 92-5 is not affected by this NTL and remains in full force and effect). All EFCs already installed and operating prior to this notice shall be subject to all of the new provisions listed below.

This office reserves the right to rescind this approval at any time should gross inefficiencies in the measurement.

No other wells can be added to this EFM approval without prior approval of this office.

Other Standards Incorporated by Reference

1. Onshore Oil and Gas Order 5, *Measurement of Gas on Federal and Indian Oil and Gas Leases*, remains in full force and effect, except as specified below:
 - Requirements III.C.4, III.C.5, III.C.14, and III.C.16 are unique to chart recorders and are waived;
 - Requirements III.C.13 and III.C.15 are unique to chart recorders and have been replaced with a similar requirement (Paragraph 8) that applies to EFCs;
 - Requirement III.C.21 is specific to AGA Committee Report No. 3, 1985. This requirement has been replaced by Paragraph 3, which allows the use of AGA Committee Report No. 3, 1992; and,
 - Requirement III.C.19, requiring chart recorders to be adjusted to zero error, is replaced by Paragraph 14, which allows some leeway in the "as left" readings during calibration.
2. EFCs shall be installed, operated, and maintained in accordance with the portions of API Chapter 21, Section 1, 1993, that apply to differential types of flow meters. In addition, Paragraphs 4, 5, 6, 8, 9, 10, 12, 13, 16, 17, and 18 specify additional requirements to API 21.1. Paragraphs 8, 10, 12, and 13, also state that only some of the provisions of API 21.1 will be enforced by BLM. Specific portions of API 21.1 are referenced at the end of each paragraph listed above.

3. All flow rate calculations shall be made in accordance with either AGA Committee Report No. 3, 1985 (API 14.3, 1985), or AGA Committee Report No. 3, Part 3, 1992 (API Chapter 14.3.3, 1992). Supercompressibility shall be determined in accordance with AGA Committee Report No. 3, 1985 (API 14.3, 1985), AGA-8, or NX-19.

Informational Requirements

4. For each meter, the EFC shall display at a minimum, the previous day gas volume, and the current instantaneous values of flowing (static) pressure, differential pressure, flowing temperature, and flow rate. The units of measure for each variable shall also be displayed. The display shall be readable without the need for data collection units, laptop computers, or any special equipment, shall be on-site, and shall be in a location that is accessible to BLM (Note: This is an additional requirement to API 21.1.5.1.1).
5. The following information must be maintained onsite and be accessible to BLM personnel without the need for data collection units, laptop computers, or any special equipment (Note: This is an additional requirement to API 21.1.5.1.1):
 - Meter run inside diameter;
 - Orifice bore or other primary device dimensions necessary for device verification, beta ratio determination, and gas volume calculation;
 - Make, range, and model number of each transducer/transmitter;
 - Calibrated span of each transducer/transmitter;
 - Differential pressure and static pressure transducer accuracies;
 - Atmospheric pressure or elevation above sea level;
 - The physical location of the flowing (static) pressure (upstream or downstream);
 - A unique meter identification number; and,
 - Specific gravity of the gas.
6. All records required by API 21.1.6, shall be retained for at least 6 years, and shall be made available to BLM upon request (Note: This is an additional requirement to API 21.1.6.8).
7. Upon BLM's request, the operator shall submit all technical documentation pertaining to the EFCs that are installed. This includes installation instructions, calibration procedures, software and algorithm details, and technical specifications.

Verification and Calibration

8. "As found" readings for the differential pressure and static pressure transducers/transmitters shall be recorded at 0% and 100% of calibrated span, and at one point that represents the normal operating pressure of each transducer/transmitter (Note: The inclusion of a verification point at the normal operating pressure is an additional requirement to API 21.1.8.3.1.2 and .3. BLM will not enforce the provisions of API 21.1.8.3.1.2 and .3 that require more verification points than those specified in this requirement).
9. If any of the "as found" readings required in Paragraph 8 are off by more than the transducer/transmitter specification for accuracy, expressed in units of measure (inches of water column or psi), that transducer/transmitter shall be calibrated in accordance with the manufacturer's specifications. Refer to *Example 1 of the Attachment* for details. (Note: This is an additional requirement to API 21.1.8.3).
10. If either transducer/transmitter required calibration, then prior to returning a meter to service, "as left" readings for those transducers/transmitters shall be recorded at 0% and 100% of

calibrated span, and at one point that represents the normal operating pressure of each transducer/transmitter. (Note: The inclusion of an "as left" verification point at the normal operating pressure is an additional requirement to API 21.1.8.3.1.5. BLM will not enforce the provisions of API 21.1.8.3.1.5 that require more "as left" verification points than those specified in this requirement).

11. If any of the "as left" readings required in Paragraph 10 are off by more than the transducer/transmitter specification for accuracy, expressed in units of measure (inches of water column or psi), the transducer/transmitter shall be repaired or replaced within 48 hours.
12. An "as found" reading for the temperature transducer/transmitter shall be obtained near the normal flowing temperature of the gas (Note: The requirement for an "as found" measurement at the normal flowing temperature of the gas is an additional requirement to API 21.1.8.3.1.4. Provisions of API 21.1.8.3.1.4 beyond this requirement will not be enforced by BLM).
13. If the "as left" readings for the temperature transducer/transmitter are not within 2.0°F of the test device, the temperature transducer/transmitter shall be replaced within 48 hours (Note: Provisions of API 21.1.8.3.1.4 exceeding the requirements of this paragraph will not be enforced by BLM).
14. If, during a verification or calibration, transmitter/transducer errors result in a flow rate error greater than 2% at the normal flowing conditions tested, the volume shall be corrected in addition to adjusting the transducers/transmitters to the standards specified in Paragraphs 11 and 13. In addition, the operator shall submit a corrected report adjusting the volumes of gas measured, and showing or discussing all the calculations made in correcting the volumes. The volumes shall be corrected back to the time the inaccuracy occurred, if known. If this time is unknown, volumes shall be corrected for the last half of the period elapsed since the date of last verification or calibration.

Other Requirements

15. For meters measuring more than 100 Mcf per day on a monthly basis, the EFC shall be installed, operated, and maintained to achieve an overall measurement uncertainty of $\pm 3\%$, or better, of true flow rate. The calculation of uncertainty shall be done in accordance with AGA Committee Report No. 3, Part 1, 1991 (API 14.3.1, 1991) or other method that has been approved by the authorized officer. BLM may prescribe operating limits to implement this requirement.
16. Unless otherwise approved by BLM, the low flow cutoff (*see Example 2 of the Attachment*) shall not be set higher than 1.5 times the manufacturer's basic uncertainty specification for the differential pressure transducer/transmitter, expressed in inches of water column, or 0.5", whichever is less (Note: This is an additional requirement to API 21.1.4.2.3).

17. Upon BLM's request, configuration logs, daily quantity transaction records, and event logs shall be submitted within 2 working days.

a. Configuration Logs

Configuration logs shall be retrieved and saved at least once per month. In addition to the configuration log requirements in API 21.1.6.4, the following information must be included:

- Well name and number or point of measurement identifier if different than an individual well;
- For non-orifice meters, all primary device information (e.g. size, beta ratio, and discharge coefficient) needed to determine gas flow rate;
- Method of determining gas volume (i.e. AGA 1985, AGA 1992) and supercompressibility (i.e. AGA 8–Gross, AGA 8–Detail, NX-19);
- Averaging technique (i.e. API 21.1.4.4) used to determine hourly and monthly averages of flowing temperature, flowing pressure, and differential pressure;
- BTU content; and,
- Instantaneous values of differential pressure, flowing pressure, flowing temperature, and flow rate at the time the configuration log was retrieved.

b. Daily Quantity Transaction Records

In addition to the requirements in API 21.1.6.2 and 21.1.6.2.1, the following information must be included:

- Well name and number or point of measurement identifier if different than an individual well;
- Daily integral value (referred to as "IV" in API 21.1.4.2 sections);
- Daily integral multiplier value (referred to as "IMV" in API 21.1.4.2 sections);
- Method of determining IMV (i.e. AGA 1985, AGA 1992);
- Monthly flow time total; and,
- For each calendar month, the total volume, and the overall average values of flowing temperature, flowing pressure, and differential pressure.

c. Event Logs

Event logs containing the information required in API 21.1.6.5 shall be retrieved and saved in order to provide a complete event history for a period of six years or as long as the meter has been in service, whichever is less. The following information must be included:

- Well name and number or point of measurement identifier if different than an individual well; and,
- A unique meter identification number.

18. The following items must be included on the meter calibration report form *in addition to* the requirements of On-shore Order No. 5.III.C. 24 and shall be submitted within two working days if requested by BLM:

- Well name and number or point of measurement identifier if different than an individual well;

- For non-orifice meters, all primary device information (e.g. size, beta ratio, and discharge coefficient) needed to determine gas flow rate;
- Model number of each transducer/transmitter;
- Calibrated span of each transducer/transmitter;
- *Normal operating* differential and static pressures;
- "Applied" data;
- Calculated flow rate error based on *normal operating* points;
- Date of last meter verification/calibration;
- Date *testing* equipment was most recently checked and calibrated; and,
- *Testing* equipment accuracy.

Variances from Requirements or Minimum Standards

An operator may request that the authorized officer approve a variance from any of the requirements or minimum standards prescribed in this NTL. All such requests shall be submitted in writing to the appropriate authorized officer and provide information as to the circumstances that warrant approval of the variance(s) requested and the proposed alternative means by which the requirements or related minimum standard(s) will be satisfied. The authorized officer, after considering all relevant factors, will approve the requested variance(s) if it is determined that the proposed alternative(s) meet or exceed the objectives of the applicable minimum standard(s); or if the authorized officer determines that the exemption of the requirement is justified. Variances granted by BLM under this NTL shall be limited to proposals and requirements under BLM statutory and/or regulatory authority only, and shall not be construed as granting variance to regulations under other Federal Agencies, State, or Tribal authority.

"Drift Verification and Low Flow Cutoff"

Example for Paragraphs 9, 11, and 16

Paragraph 9, 11, and 16, all reference the basic transducer/transmitter accuracy specification, expressed in actual units of measure: inches of water column or psia/psig.

The purpose of the wording in Paragraphs 9 and 11 is to recognize that even the best transducers/transmitters will drift slightly, and to allow some level of tolerance when performing a verification or calibration. Using the stated transducer/transmitter accuracy, given by the manufacturer, is an objective way to specify the tolerance. Paragraph 16 allows the low flow cutoff to be set only to compensate for transducer/transmitter drift.

Example 1: You are performing a verification of the differential pressure transducer on an EFC. The manufacturer's specifications for this transducer state an overall accuracy of $\pm 0.2\%$ of span. The calibrated span of the transducer is 0-50". Assume the normal operating differential pressure is 27.0". You obtain the following "as found" readings as required by paragraph 8:

Required Test Point	Applied Pressure (inches water)	"as found" Pressure (inches water)	Error (inches water)
Zero	0.0	0.1	0.1
100% of span	50.0	50.0	0.0
Normal operating	27.0	27.2	0.2

pressure			
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Does this transmitter need to be calibrated according to Paragraph 9?

Answer: Since the calibrated span is 50", the accuracy of the transducer, expressed in units of measure, is ± 0.1 " (0.2% of 50"). If any of the required "as found" readings are off by more than ± 0.1 ", the transducer must be calibrated. The "as found" reading at the "normal operating pressure" is 0.2" greater than the applied pressure, which is more than the ± 0.1 " allowed. Therefore, according to Paragraph 9, this transducer must be calibrated in accordance with the manufacturer's specifications. Per paragraph 11, if after calibration the transducer could still not achieve a tolerance of ± 0.1 " for all three required test points, it would have to be repaired or replaced within 48 hours.

Example 2: What is the maximum allowable low flow cutoff for an EFC with a 0-300" multivariable transmitter, spanned down to 0-200"? The performance specifications for this EFC state that the differential pressure accuracy is $\pm 0.1\%$ FS (full span).

Answer: The span in this example is 0-200", which gives an accuracy of ± 0.2 " ($\pm 0.1\%$ of 200"). Therefore, the maximum allowable value for the low flow cutoff is 1.5 times 0.2", or 0.3".