Response to Comments
New Mexico Notice to Lessees (NTL) 2008-1

General Comments

The Bureau of Land Management (BLM) received two comments referencing the National Technology Transfer and Advancement Act (NTTAA), and suggesting that BLM accept industry standards (in whole) as required by the NTTAA, rather than developing independent standards. The NTTAA, Sec 12(d)(1) states:

> *"Except as provided in paragraph (3) of this subsection, all Federal agencies and departments shall use technical standards that are developed or adopted by voluntary consensus standards bodies, using such technical standards as a means to carry out policy objectives or activities determined by the agencies and departments."*

Paragraph (3) goes on to state:

> *"If compliance with paragraph (1) of this subsection is inconsistent with applicable law or otherwise impractical, a Federal agency or department may elect to use technical standards that are not developed or adopted by voluntary consensus standards bodies…"*

In developing the draft Notice to Lessees (NTL), BLM did adopt various industry voluntary consensus standards such as American Petroleum Institute Chapter 21, Section 1 (hereafter referred to as API 21.1) relating to electronic flow measurement, American Gas Association Report Number 3 (hereafter referred to as AGA 3), and American Gas Association Report Number 8 (hereafter referred to as AGA 8). The NTL does make various exceptions and additions to the requirements of API 21.1 because some of the provisions of API 21.1 are inconsistent with applicable law or with other BLM requirements such as Oil and Gas Onshore Order Number 5 (OO5).

Oil and Gas Onshore Order 5 (OO5) remains BLM's primary standard for gas measurement on Federal and Indian land. While the NTL is specific to New Mexico and *electronic* flow measurement, OO5 has a national scope and applies to all forms of gas measurement. One of the premises in developing the draft NTL was to be consistent, where practical, with the requirements for chart recorders that are described in OO5. For example, OO5 requires a 3-point verification for chart recorders, whereas API 21.1.8.3 requires a 5-pont verification for electronic flow computers (EFC). In order to ensure that the requirements for EFCs are not more stringent than the requirements for chart recorders in OO5, BLM decided not to enforce the 5-point verification requirement in API 21.1.

As another example, OO5(III.C.19) requires chart recorders to be adjusted to "zero" error prior to placing the meter back into service. This is generally obtainable in a chart recorder because the precision of the chart recorder is less than its accuracy. In other words, combining the effects of pen width, chart line width, and subjectivity in reading charts, the appearance of “zero” error is relatively easy to achieve. Given that the precision of the readout for a transmitters or transducers often exceeds its accuracy, obtaining “zero” error during a verification or calibration is often not possible or practical. API 21.1 does not provide a tolerance for verification; therefore, even if API 21.1 were adopted in whole and without exceptions, BLM would still enforce the “zero” error provision of OO5. The verification tolerances provided in paragraphs 9 and 13 actually benefit operators because they are more practical and obtainable than the default requirements in OO5 as they would apply to EFCs.

BLM believes that we are in compliance with the NTTAA by adopting three different industry standards in the draft NTL. Exceptions and additions to the requirements of API 21.1 are necessary due to inconsistencies with applicable law and because they were otherwise impractical, as allowed by Section 12(d)(3) of the NTTAA. No changes were made based on these comments.

The New Mexico State Office received two comments suggesting that BLM work with industry to review and revise existing standards and to participate in technical forums to achieve a common understanding of EFC measurement practices. We agree with this comment. Since 2004, BLM has been actively participating in the development of new API standards and revisions of existing standards, including API 22.1, 22.2, 22.4, 22.5, 21.1, 14.3, and the newly formed Committee on Petroleum Measurement and Allocation. Because no wording changes were suggested by the commenter and BLM is actively working to address these comments, no changes to the NTL were made.

Several comments suggested that BLM develop a consistent national standard similar to OO5, which references industry standards. BLM agrees with this comment and is working towards this goal. However, the revision of a national standard such as OO5 is a long and tenuous endeavor. Several attempts at revising OO5 have been made since the early 1990’s, including the proposed 43 CFR 3100 revisions in 1998; none of which have been successful for one reason or another. Even under the best circumstances, the revision of OO5 is at least 3 years away. BLM feels strongly that the requirements in the draft NTL are long overdue and has developed the NTL process as a temporary solution until such time as OO5 is revised. BLM policy (WO IM 2006-233) requires that a consistent “model” NTL be proposed for each state wishing to develop an NTL for EFCs. This process has helped ensure national consistency between states.

When or if Onshore Order 5 is revised, BLM intends to rely on industry standards as much as possible per the NTTAA. However, even with BLM’s participation on standards development organizations such as API, it is unlikely that BLM will ever be able to accept an industry standard in whole, with no exceptions or additions. The goals, purposes, and limitations of industry standards are often very different from the goals, purposes, and limitations that BLM must adhere to. No changes to the draft NTL were made as a result of these comments.

We received several comments stating that the NTL is not necessary for BLM to carry out its mandated responsibility and is, therefore, unnecessary. The commenters argued that since BLM is currently carrying out gas accountability without the NTL, it must not be necessary. We do not agree with this statement and reject the comments. Without this NTL, BLM is unable to enforce[1] many deficiencies related to EFCs which makes it difficult or impossible for us to carry out our overall mandate to ensure that Federal and Indian gas is accurately measured and properly reported. The following bullet items give several examples of how our core responsibilities have been affected without the NTL:

- BLM was unable to enforce[1] requirements for on-site information, which inhibited our ability to verify the calculated flow rate and determine overall meter station uncertainty. Both of these functions are critical to our core mission regarding gas accountability for Federal and Indian leases;
- BLM was unable to enforce[1] any of the provisions of API 21.1, including calculation methodologies, reporting requirements, and calibration/verification procedures, all of which help ensure that gas is being accurately measured and properly reported on Federal and Indian leases;
- BLM was unable to enforce[1] low-flow cutoff standards which could have resulted in significant volumes of unreported gas being removed from Federal and Indian leases.

While it is true that BLM was able to accomplish some level of gas accountability prior to the implementation of the NTL, much of this was due to fortuitous and voluntary compliance with the standards in the NTL on the part of industry and the issuing of case-specific written orders by the local field offices. However, the use of written orders also resulted in a great deal of inconsistency from state to state and office to office. The development of consistent national standards has been a predominate theme for the industry.

BLM received two comments stating that this NTL would result in considerable unnecessary expense and would be unduly burdensome on industry. One of the comments mentioned that existing EFC programs and operating procedures would need to be changed and some EFCs would have to be replaced because they cannot be updated to meet these requirements. No specific information was provided as to exactly what programs or operating procedures would need to be changed or what provisions of the NTL would require the replacement of some EFCs; therefore, it is difficult to respond in detail. Nearly all the requirements of the NTL are already required by API 21.1, other API standards, or federal law. The only requirement that may require expenditure by industry is the requirement for a display; however, industry has not made the case that is will be significant enough to result in wells being shut in or production curtailed. We are aware that there are still a number of EFCs without a display, especially in the Farmington area. The response to comments regarding the display are discussed in detail

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[1] Even without the NTL, BLM could enforce these requirements through the Written Order and variance approval process. However, this would be done on a case by case basis and would result in enormous inconsistencies from state to state and office to office. Throughout the development of the "model" NTL, from which this NTL is derived, industry expressed a strong desire for national consistency.

under “Paragraph 4”. Because the NTL enforces the calculation procedures of API 21.1, 14.3, and AGA-8, we cannot envision why EFC programs would have to be changed as a result of this NTL. In many cases, EFC’s not meeting the uncertainty requirements of Paragraph 15 could be brought into compliance through re-spanning, re-locating, or installing smaller orifice plates to increase differential pressure.

Some of the provisions of the NTL are actually less restrictive and less burdensome than existing requirements. For example:

- Implementation of this NTL gives automatic approval for the use of the AGA Report No. 3 (1992) flow equation. Without this NTL, operators would have to request a meter-specific variance request to use anything besides the AGA Report No. 3 (1985) flow equation. This represents a savings in time and paperwork.
- Implementation of this NTL provides consistent requirements with other states that have recently issued NTLs for EFCs including California, Montana, Utah, and Wyoming (the Wyoming NTL does have some minor differences that will be corrected in the near future). Consistency across field office and state office boundaries was one of the primary concerns of industry in the development of this, and other, NTLs.
- Strict adherence to Onshore Order 5 could require differential and static pressure transducers to operate in the outer 2/3 of their calibrated spans. This NTL provides the option of uncertainty based measurement which, in the vast majority of cases, is far less restrictive.
- API 21.1.8.3.1.4 requires the flowing temperature transducer to be calibrated if the “as found” value of flowing temperature is more than 0.5º from the reference standard. The NTL allows a difference of 2.0ºF.

In summary, we do not believe that the requirements of this NTL are excessively burdensome or costly and no changes to the NTL were made as a result of these comments. Our experience with other NTLs such as WY NTL 2004-1, which has been in place for over 3 years, has shown that compliance is relatively easy and places very little burden on industry. We are not aware of any wells or leases that were shut in or curtailed as a result of the implementation of WY NTL 2004-1, nor did the Wyoming BLM offices receive any significant complaints from industry during the implementation phase. In extreme cases where an operator would incur significant expenses in order to comply with the NTL, a case-specific variance could be requested from the local BLM office.

One comment suggested that BLM wait for the new version of API 21.1 to be published before pursuing the NTL, as the new API 21.1 should be out “in the near future” and may alter some of the existing requirements. As a participant on the API 21.1 working group, BLM fully appreciates the amount of work that has gone into the revision so far and the tremendous amount of work left to do. We believe it is highly unlikely that the revised version of API 21.1 will be completed and balloted “in the near future”.

It is the intent of BLM to initiate a revision of Onshore Order 5 once API 21.1 and other standards are finalized. A new Onshore Order 5 would supersede the NTLs and adopt much of the new industry standards. The New Mexico State Office feels that it is appropriate and necessary to implement the NTL at this time and not base timeframes on the tentative completion dates of other documents. If significant changes to API 21.1 are finalized in the near future that would affect the provisions of the NTL, it would be relatively simple and quick process to issue an amended NTL in order to comply with the revised standard.

BLM received several comments objecting to the "picking and choosing" of parts of API 21.1 that will be enforced and stating that we should adopt it in whole. While BLM recognizes this comment and is actively working to address the concerns raised by the commenter, no changes to the NTL were made as a result.

To date, New Mexico has not recognized or enforced any of the provisions of API 21.1. We feel that even without the revisions currently being developed, API 21.1 in its current form sets forth useful and necessary standards for EFCs. Unfortunately, API 21.1 contains several statements that: 1) exceed existing requirements for chart recorders under OO5; 2) conflict with existing laws, or; 3) do not adequately define violations for the purposes of enforcement. Therefore, nine specific additional requirements to API 21.1 have been included in this NTL. In addition, four of the provisions of API 21.1 will not be enforced by BLM. As a result, BLM will be able to enforce the remaining provisions. For the most part, the additional requirements are minor and should not represent a significant burden to the industry. We felt it was more beneficial to adopt the majority of API 21.1, with a few additional requirements, than to not adopt it all.

Several comments expressed concern that most contracts reference API 21.1 and that because the NTL deviates from API 21.1, there could be some derogation of contractual provisions. While the NTL does require some additional provisions to API 21.1, we do not believe that any of these contradict the provisions of API 21.1 in a manner that would affect gas sales contracts. No changes to the NTL were made as a result of the comments. The additional provisions are summarized below:

- Paragraph 4 requires the use of display whereas API 21.1.5.1.1 gives the option of display. The requirement for a display does not conflict with API 21.1, it just clarifies one of the options that API 21.1 allows. Operators can still use laptops or data collection units; however, a display must also be present.
- Paragraph 5 requires some information to be on-site that is in addition to the on-site data requirements of API 21.1. None of the additional information required conflicts with the on-site data already required in API 21.1.
- Paragraph 6, as well as the Federal Oil and Gas Royalty Management Act, require data to be retained for at least 6 years. API 21.1 requires data to be retained for *at least* 2 years "unless specified by regulation, tariff, or contract". As the NTL is essentially a regulation, the data retention period required by the NTL is in accordance with API 21.1.
- Paragraph 8 requires 3 "as found" verification points for differential and static pressure: zero, 100% of span, and one point that represents the normal operating point of the transducer. API 21.1 requires 5 verification points and does not

include the “normal point” that the NTL requires. The inclusion of the “normal point” is an additional requirement and does not preclude the testing of any of the points required in API 21.1. Also, the required verification points of zero and 100% of span does not preclude the operator from verifying additional points to be in compliance with API 21.1.

- Paragraph 9 defines a verification tolerance based on the reference accuracy of the device, whereas API 21.1 generically states that a calibration is required “whenever the verification test determines an unacceptable difference between the value measured or produced by the certified reference standard and that of the value measured and utilized by the EGM”. The NTL is merely defining the “unacceptable difference” referenced in API 21.1.
- Paragraph 10 requires “as left” verification points for differential and static pressure at zero, 100% of span, and one point that represents the normal operating point of the transducer. As described above (Paragraph 8), this requirements does not preclude compliance with API 21.1.
- Paragraph 12 requires that the temperature transducer be verified near the normal flowing temperature of the gas. API 21.1 requires “verification of the fluid’s temperature…”. We believe that the requirements of the NTL and 21.1 are sufficiently vague that they are not in conflict. The requirements in the NTL were left intentionally vague because Onshore Order 5 has essentially no requirements for verification of the temperature element.
- Paragraph 13 requires the temperature transducer to be within 2.0ºF whereas API 21.1 requires a tolerance of 0.5ºF. As the NTL defines minimum standards, there is no prohibition against compliance with the tighter tolerances of API 21.1.
- Paragraph 16 establishes a maximum value for the low flow cutoff of 0.5”, whereas API 21.1 *recommends* that it “be determined by the contractually concerned parties based upon a realistic assessment of site conditions”. Any contractual values of low flow cutoff set lower than 0.5” would not be in violation of the NTL as 0.5” is set as a maximum value. If a contract stated that the low flow cutoff be set higher than 0.5” (this would be very rare), the operator could apply for a variance to this requirement. It is also important to note that API does not have a standard for low flow cutoff, only a recommendation.

One comment objected to “BLM interference” into third party contracts, stating that some of the provisions of the NTL were in conflict with third party contracts that the commenter had entered into. The commenter asked that items which would require changes to existing contracts be dropped from the NTL. The commenter did not specify which provisions of the NTL were in conflict with their third party contracts.

BLM has no authority over third party contracts. Our only authority is over companies that operate on Federal and Indian leases. This authority is granted to BLM through the lease instrument which acts as a contract between BLM and the operator and which applies all applicable regulations to the operator. This NTL is authorized under 43 CFR 3261.2. BLM believes that all the provisions of this NTL are necessary to carry out our core mission of ensuring accurate measurement and proper reporting of gas produced and removed from Federal and Indian leases. We are aware that some of our requirements, both in this NTL and in Onshore Order 5 may be in conflict with some of the sales and transportation agreements that the operator has with third parties. We are also aware that some contracts are not "arms-length" in nature and often contain negotiated terms that do not necessarily represent good measurement practice. Conflicts between BLM requirements and third party contracts are outside of BLM's control. Because Federal and Indian oil and gas operators must comply with BLM requirements regardless of the provisions contained in other contracts, no changes to the NTL were made.

BLM received one comment asking what the expected increase in accuracy will be by implementing this NTL. Before answering this question, we would like to clarify that establishing accuracy (uncertainty) limits is only one of the goals of this NTL. Other goals include the ability to field verify EFCs, enforce existing industry standards such as API 21.1, and establish objective and enforceable standards for calibration and low flow cutoff. As far as uncertainty, we feel that this NTL will result in a significant improvement in overall measurement uncertainty. Our experience in New Mexico and in other states is that uncertainty greater, sometimes much greater, than ±3% is relatively common in metering stations, even in those measuring more than 100 Mcf/day. The most prevalent cause for this is the operation of transducers at a very low percent of their span. Paragraph 15 of this NTL establishes uncertainty limits which will ensure that meters measuring more than 100 Mcf/day will have an overall measurement uncertainty of ±3% or better, which we believe will be a significant improvement over the existing conditions. No changes to the NTL were requested by the commenter and none were made as a result.

A similar comment stated that implementing this NTL will not increase volumes, revenues, or taxes, and that industry will not get any benefit from the expenditure required to comply with this NTL. First, as stated previously, we do not believe that complying with this NTL will result in significant expenditure to industry. Second, it is not our intent to increase volumes, revenues, or taxes with this NTL. BLM's mandate is to ensure that gas produced from Federal and Indian leases is accurately measured and properly reported and we believe this NTL will help fulfill our mandate by setting accuracy (uncertainty) limits, and helping to ensure that reported volumes are verifiable. No changes to the NTL were made as a result of this comment.

We received one comment stating that BLM is not concerned with the cost of compliance when new NTLs are established and that it doesn't matter how much the industry has to spend to comply. We believe the commenter has overstated the intent of our position. Our primary goal in issuing this NTL is to help ensure accurate measurement and proper reporting of gas produced from Federal and Indian leases. While it is true that the cost of implementing requirements to achieve our goals is not our primary concern, any requirements that would cause wells to be shut in prematurely or that would result in curtailed production would be unacceptable to us. Any such requirements would also be contrary to the Energy Policy Act of 2005. We do not believe that complying with this NTL will result in significant costs. Industry has not provided any data in these comments or in comments received on NTLs in other states to support their contention of a signification cost to comply. In addition, we are not aware of any wells being shut in or production being curtailed in other states that have already implemented the NTL. In the case that an operator can demonstrate that the requirements of the NTL will cause economic hardship, individual operators can apply for a variance. No changes to the NTL were made as a result of this comment.

One comment requested that BLM consider the economic impact of this proposed NTL and assess the effects of this NTL on the nation's energy supply, distribution, use, and cost and benefit to the industry in accordance with Executive Orders (E.O.) 12866 and 13211. This NTL is not a significant regulatory action as defined in E.O. 12866. It will not have an annual economic effect of $100 million or adversely affect an economic sector, productivity, jobs, the environment, or other units of government. In accordance with E.O. 13211, the BLM has determined that the proposed rule will not have substantial direct effects on the energy supply, distribution or use, including a shortfall in supply or price increase. The NTL informs operators of the minimum standards and requirements for EFCs located within New Mexico, Oklahoma, Kansas, and Texas. The provisions of the NTL do not represent a significant change from existing industry standards, and therefore will have little economic impact and will not have a substantial effect on the energy supply, distribution or use. No changes to the NTL were made as a result.

One comment requested that BLM circulate this response to comments for further review and comment by industry. In implementing this NTL, BLM is following the requirements of the Administrative Procedures Act which requires any new rulemaking to be made available to the public and that BLM receive and consider comments on the rulemaking before making it final. No changes were made as a result of this comment.

The New Mexico State Office received one comment requesting that meters installed prior to the effective date of this NTL be "grandfathered" under the requirements of the New Mexico EFC NTL issued in 1999[sic]. The argument made by the commenter is that existing EFCs are already in compliance with BLM requirements and operators should not be forced to replace them just because they would no longer comply with this NTL.

The actual NTL the commenter is referring to is New Mexico NTL 89-2, approved on November 3, 1989, not 1999 as the commenter stated. NTL 89-2 was the first NTL ever issued by BLM addressing EFCs and even preceded API 21.1 by four years. While NTL 89-2 has served its purpose, we do not feel it is unreasonable to revise our minimum standards for EFCs considering the advances in technology and industry standards that have been made over the past 19 years. As stated previously, the provisions of NTL 89-2 are not sufficient for BLM to enforce requirements necessary to carry out our mandated responsibilities. This fact has been documented in various internal reviews which found that insufficient regulatory guidance in New Mexico had greatly impaired the ability of several offices to conduct production accounting.

As far as "grandfathering" existing meters, one of the purposes of an NTL is to provide consistent requirements for all meters within the jurisdiction of the NTL. If existing installations were grandfathered, it would result in inconsistent requirements based on the installation date of the meter. Not only would this be very complex for us to track and enforce, but in other comments, industry has expressed a desire for consistent measurement standards, which we feel can only be accomplished by making this NTL retroactive to all electronic flow computers. In addition, our ability to carry out our mandated responsibilities would be adversely affected for meters that had been grandfathered. Instead of grandfathering, the NTL establishes timeframes for compliance that were developed as a result of industry comment. We feel that the timeframes are reasonable and do not impose a significant financial burden on industry. No changes were made as a result of this comment.

One comment objected to the implication that the NTL was needed to allow unrestricted access to Federal and Indian meter locations because of safety and liability concerns. Actually, the Federal Oil and Gas Royalty Management Act gives BLM the authority for unrestricted access to Federal and Indian leases, not the NTL; the NTL merely describes the information that must be on-site and accessible to us.

BLM is also very concerned about the safety of our inspection personnel and will work with operators to ensure inspections can be made in a safe manner. However, Section 108(b) of FOGRMA mandates that BLM be given unrestricted access to leases:

> *"Authorized and properly identified representatives of the Secretary may without advance notice, enter upon, travel across and inspect lease sites on Federal or Indian lands and may obtain from the operator immediate access to secured facilities on such lease sites, for the purpose of making any inspection or investigation for determining whether there is compliance with the requirements of the mineral leasing laws and this Act".*

Federal regulations implementing FOGRMA further state:

> *"The operator shall permit properly identified authorized representatives to enter upon, travel across and inspect lease sites and records normally kept on the lease pertinent thereto without advance notice."* (43 CFR § 3162.1(b))
>
> *"Any person shall be liable for a civil penalty of up to $10,000 per violation for each day such violation continues...if he/she: (1) Fails or refuses to permit lawful entry or inspection authorized by 3162.1(b) of the title:"* (43 CFR § 3163.2(e)(1))

These are statutory requirements that are beyond the scope of this NTL to change. BLM does not have the legal authority to waive or modify these requirements and we believe that these provisions are necessary to ensure production from federal and Indian leases is properly measured and accounted for. No revisions to the NTL were made as a result of this comment.

Paragraphs 4 and 5

One comment objected to the information retention requirements in both Paragraphs 4 and 5, claiming them to be burdensome without any corresponding benefit that would improve the information available to BLM. The commenter then went on to state that the electronic readout may not be able to display all the necessary data and that the data can be retrieved through an audit request.

The display requirements in Paragraph 4 are available on virtually every make and model of EFC that BLM is aware of on Federal and Indian land; therefore the requirement to display the required information in Paragraph 4 should not be burdensome. The data requirements of Paragraph 4, in conjunction with the requirements of Paragraph 5, serve several purposes critical to BLM's core mission of ensuring that gas produced from Federal and Indian leases is accurately measured and properly reported:

- The on-site information allows BLM to independently calculate an instantaneous flow rate and compare it with the flow rate displayed on the EFC. Significant differences *may* indicate that the EFC has been programmed with erroneous set-up parameters or that there is a calculation error;

- The data shown on the display is raw and unedited, giving BLM a level of assurance that is not possible with data requested after-the-fact;

- Onsite data can be used by BLM to determine "normal" operating conditions that is used as one of the required calibration points;

- Onsite data allows the calculation of overall meter station uncertainty as required in Paragraph 15(b).

BLM cannot rely solely on audits to fulfill our mandated responsibilities for two reasons. First, numerous internal reviews from the Inspector General and General Accounting Office have historically found material weaknesses in our inspection and enforcement programs and have emphasized the need for "field verification" and "field presence". Second, given the limited number of inspection and enforcement staff, and multiple responsibilities that are assigned to them, the field verifications are a quick, easy, and efficient way to identify potential problems and prioritize audit workloads without relying on or waiting for industry assistance or involvement.

In summary, BLM does not believe the requirements of Paragraph 4 or 5 to be burdensome and feels that they are essential to BLM's core mission regarding production accountability. No changes to the NTL were made as a result of this comment.

Several comments stated that the meter software may not provide electronic readout of all the required information and requiring this information may result in costly replacement of many older EFCs. The commenter also stated concerns about updating the information every time a change is made, especially considering that it can be obtained through audit.

The necessity of having the information required by both Paragraphs 4 and 5 is discussed above. In regards to the commenter's concern about meter software being able to provide electronic readout of all the required information, we want to emphasize that the onsite data requirements of Paragraph 5 do not have to be part of the display. For example, the meter run inside diameter is typically stamped on the flange or plate holder. As long as this value is readable and accessible, the requirement has been met. Likewise, the requirement for make, range, and model number of each transducer/transmitter will be met as long as the manufacturer's identification tag is readable and accessible on site. Other parameters, such as physical location of the static pressure tap, calibrated spans, orifice size, and specific gravity can be written on a data card and placed at an on-site location. It could also be part of the display if the EFC has that capability. No changes to the NTL were made as a result of this comment.

Several comments expressed concerns about maintaining the currency of the information required in Paragraph 5. One comment went on to say that flow computers will need to be replaced to meet this requirement which would be cost prohibitive. We realize that maintaining current data on site can be an additional workload, especially as it relates to specific gravity since that value can change frequently. For this reason, the wording of Paragraph 5 is such that it is not a violation if the data is not current; it is only a violation if the data is not there. If, for example, it was discovered during an inspection that the specific gravity posted on site was not the most recent value, the BLM would not issue an Incident of Non Compliance. Instead, we would issue a Written Order to update the specific gravity to match the most recent gas analysis. A violation could be issued if the operator did not comply with the Written Order.

Additionally, the purpose of the on-site data is to check the displayed flow rate, given the on-site data available. Unless the specific gravity used in the EFC is significantly different from that displayed on-site, it is unlikely that the difference in calculated flow rate would be significant enough to result in a "failed" field verification (note that a "failed" field verifications simply means more research is needed to explain the discrepancy, and is not, in itself, a violation). Based on the intent and wording of this requirement, we do not believe that any existing EFCs would have to be replaced to comply. No changes to the NTL were made based on this comment.

One comment questioned the need for displaying the specific gravity on-site when all calculations are performed off-site. The commenter went on to state that only the flow extension and temperature are used from the EFC on-site, and all other data is maintained in an off-site database. We realize that off-site calculations are relatively common and are allowed by API 21.1. However, even if off-site calculations are performed to derive final volumes, the information required by Paragraphs 4 and 5 is still required at the meter. The values displayed on location do not necessarily have to be final settlement values. There is no violation if an inspector finds a significant discrepancy between the displayed flow rate and the flow rate calculated manually; it simply indicates that more research into the issue is warranted.

In most situations, BLM inspectors would have no indication of whether calculations were being done on-site or off-site, and would have no way of verifying where the calculations were being done even if it was indicated. For this reason, we felt that we must apply consistent requirements to all EFCs and no changes to the NTL were made as a result of this comment.

One comment objected to the requirement of maintaining records on site in remote locations, and that record retention at the nearest office should be acceptable. The necessity of providing the information required in Paragraphs 4 and 5 has already been described. In specific cases, the operator can apply to the local BLM office for a variance from the requirement for on-site information. The variance request would have to justify the reason the variance is needed and provide an alternative to the requirement that would not inhibit BLM's ability to carry out the intent of these requirements. No changes to the NTL were made as a result of this comment.

One comment stated that some companies are now able to remotely update the specific gravity as soon as a new analysis is available. Because of this, the commenter raised a concern that the requirement for specific gravity to be displayed on-site would actually make the measurement less accurate in meters that cannot display it automatically. The reasoning is that the EFC would have to use an older outdated value of specific gravity until someone was able to come out and manually enter the gravity and update the data card at the same time. It is not BLM's intent to make measurement less accurate. In fact, the wording of Paragraph 5 was intentionally designed so that it would not be a violation if the specific gravity listed on-site was not up to date.

To explain the wording of Paragraph 5, we will use a hypothetical case where the specific gravity is updated remotely based on a new analysis and a BLM inspector performs a field verification on the meter before the operator is able to update the data card. First, unless the updated value of specific gravity had changed significantly (greater than 4 or 5%) it is unlikely that the field verification would even detect that a new specific gravity was being used by the EFC. Assuming, however, that the field verification did identify a significant discrepancy, the inspector would simply flag the meter as requiring a more in-depth verification. This would most likely result in an audit where the cause of the discrepancy – in this case an old value of specific gravity – would be discovered. Upon this determination, BLM would send the operator a written order to update the specific gravity posted on-site with the new value. The written order would also contain a reasonable time-frame for compliance. If, and only if, the operator did not comply with the written order would a violation be issued. Even under this worst-case scenario, the operator has ample time to update the data card without fear of receiving an Incident of Non Compliance. In the meantime, the EFC can use the latest value of specific gravity for volume calculations with no derogation of measurement accuracy. No changes to the NTL were made as a result of this comment.

Paragraph 6

BLM received two comments objecting to the required 6-year retention of data, stating that it was left over from the days of chart recorders and should not apply to EFCs. The comment went on to say that the 6-year data retention requirement is very costly. The commenter also made the observation that FERC only requires data retention for 3 years.

Federal oil and gas lessees and operators have a statutory requirement to retain data for at least 6 years because of Section 103(b) of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) which states:

> *"Records required by the Secretary with respect to oil and gas leases from Federal or Indian lands…shall be maintained for 6 years after the records are generated…"*

To change this requirement would require a legislative amendment to FOGRMA, which is well beyond the scope and authority of this NTL. No changes were made as a result of this comment.

BLM received one comment objecting to the operator being held responsible for collecting and maintaining the audit trail data on meters because the operator typically does not own or operate the meter. The commenter suggested that the pipeline companies who own the meters be made the responsible party. We partially agree with this comment. Section 103(a) of The Federal Oil and Gas Royalty Management Act states:

> *"A lessee, operator, or other person directly involved in developing, producing, transporting, purchasing, or selling oil or gas subject to this Act through the point of first sale or the point of royalty computation, whichever is later, shall establish and maintain any records,, make any reports, and provide any information that the Secretary may, by rule, reasonably require for the purposes of implementing this Act or determining compliance with rules or orders under this Act."*

In addition, Federal Regulations (43 CFR 3162.7-1(c)(2)) states:

> *"Any person engaged in transporting any oil or gas by pipeline from any lease site, or allocated to any lease site, shall maintain documentation showing, at a minimum, the amount, origin, and intended first purchaser of such oil or gas."*

Both the Act and the Regulations state that a pipeline company (purchaser and/or transporter) is also responsible for maintaining records and documentation pertaining to the production of oil and gas from Federal and Indian leases. However, BLM regulations are vague on how we would enforce the submittal of such records from anyone but the operator and the portions of the FOGRMA dealing with transporters or purchasers have typically gone to the MMS for implementation. For this reason, BLM has historically not gone directly to the purchaser/ transporter to get audit trail data and as a result there is little precedent for us to consider this course of action. Although we believe the commenter has made a valid argument, we will continue going through the lease operator for data until we receive guidance and legal opinion to the contrary. In any case, no changes were made to the NTL because the language of the NTL does not specify the responsible party.

<u>Paragraph 7</u>

BLM received one comment asking that information submitted to BLM under this Paragraph be held as confidential.

BLM generally holds data received by oil and gas operators as confidential under § 552(b)(4) and (9) of the Freedom of Information Act. Section 552(b)(4) exempts "trade secrets and commercial or financial information obtained from a person as privileged or confidential", and Section 552(b)(9) exempts "geological and geophysical information and data, including maps, concerning wells". If the operator believes data requested under Paragraph 7 is confidential, each page should be clearly marked with the words "Proprietary and Confidential". However, BLM cannot guarantee that the data will remain confidential if the determination of confidentiality under the above-referenced paragraphs is challenged and overturned.

<u>Paragraphs 8 and 10</u>

BLM received one comment objecting to the requirement to verify the static pressure transducer at 100% of span. The commenter stated that their company policy only calls for calibration at line pressure and this requirement will force their calibrators to carry high-pressure nitrogen bottles.

The requirement in Paragraph 8 to perform a verification at 100% of span is also required by API 21.1.8.3.1.3. Because verification at 100% of span is standard industry practice and as the commenter did not provide any justification, other than cost savings, to use line pressure in lieu of 100% of span, we reject this comment.

BLM received one comment stating that the determination of a "normal operating point" with a fluctuating well is difficult and that a BLM should allow a range of values. While the requirement of performing a verification at the normal point is still necessary for fluctuating flows, we agree that defining the normal point is open for interpretation. It could be that the verification points required by API 21.1 would be adequate in these cases, or there could be other options such as using the average values of static and differential pressure from a recent volume statement as the normal points. While we agree with the comment, we believe this is a training issue both internally and with industry and is not cause for a wording change in the NTL, as the requirement to perform a normal point verification is still necessary regardless of the type of flow being measured. No changes to the NTL were made as a result of this comment.

Paragraphs 11 and 13

BLM received a comment stating that the required 48-hour timeframe for equipment replacement could be burdensome if the failure occurred over a weekend or holiday. The commenter suggested that a three-day time frame would be more practical.

BLM is aware that there may be special circumstances where the 48-hour timeframe is unworkable. This could be due to a holiday or weekend, or the unavailability of parts or work crews. In these instances, the operator should work with the local BLM office in requesting a variance to the 48-hour requirement. No changes to the NTL were made as a result of this comment because we believe that 48 hours is reasonable in the vast majority of cases.

Paragraph 14

One comment objected to the requirement for the lease operator to submit amended reports if an error of greater than 2% is discovered during a calibration. The basis of the objection is that the meters are typically owned and operated by the purchaser/transporter, and the lease operator may not have access to this data. The commenter asked that the purchaser be held as the responsible party rather than the lease operator. The wording in this paragraph specifically requires the operator (i.e. lease operator) to "submit a corrected report". We are rejecting this comment because federal regulations at 43 CFR 3162.4 specifically require the operator to submit reports to BLM and MMS and do not provide the option of having a purchaser or transporter submit the required reports.

Paragraph 15

BLM received several comments stating that the uncertainty requirement in this paragraph is unprecedented and not addressed in OO5 or API standards.

While we agree that operating and uncertainty limits are not explicitly addressed by API standards, we do not agree that they are unprecedented and not addressed in OO5. In fact, OO5, III.C.4 and III.C.5, both require that differential and static pens operate in the outer 2/3 of the chart. These requirements in OO5 establish operating limits and set a precedent for BLM to enforce operating limits. Paragraph 15(a) of the NTL is virtually the same as the OO5 requirements.

BLM recognizes that most EFCs perform better than chart recorders and an expanded operating range is usually justified as a result. In order to quantify the expanded operating range, BLM performed an uncertainty analysis of chart recorders and orifice plates operating at the minimum limits allowed by OO5. It was determined that such a meter would have an overall measurement uncertainty of ±3%. This level of uncertainty then became the performance standard for EFCs in Paragraph 15(b), as an alternative to the outer 2/3 requirement in Paragraph 15(a). Because OO5 was used as the basis for both Paragraphs 15(a) and 15(b), we disagree with the comment and we made no changes as a result of the comment.

One comment argued that the term uncertainty can be confused with inaccuracy, and that meter stations not meeting the uncertainty specification in Paragraph 15(b) may be misconstrued to be reading inaccurately. We understand the point being made by the commenter, and agree that confusion does exist with the terminology. Uncertainty, as used in the NTL, is the statistical range of inaccuracy that *may* be occurring in a meter. It is also true that a meter operating with a high degree of uncertainty may not have any inaccuracy. However, the high degree of uncertainty increases the *probability* or *risk* of inaccuracy. We do not believe wording changes in the NTL would clarify the difference between uncertainty and inaccuracy (and no wording changes were suggested by the commenter). Clarifying the meaning of uncertainty and inaccuracy will be an ongoing educational effort among both BLM and industry. No changes were made as a result of this comment.

One comment stated that the process of determining uncertainty assumes that each of the elements of uncertainty act in the same direction, which results in the calculated uncertainty being overstated. We do not agree with this statement. The root-sum-square statistical method described in API 14.3.1 (1991) and used by BLM to determine uncertainty does, in fact, assume that some sources of uncertainty will be offsetting.

For example, assume that a measurement system consists of only two components A and B. The uncertainty of component A is assumed to be ±5% and the uncertainty of component B is assumed to be ±2%. If the offsetting effects were not taken into consideration, the total uncertainty of the measurement system would be ±7% (the algebraic sum of the two components). However, the root-sum-square method, employed by BLM, gives the following result:

$$U_{system} = \sqrt{U_A^2 + U_B^2} = \sqrt{5^2 + 2^2} = \pm 5.39\%$$

where:

U_{system} = uncertainty of the measurement system (%)
U_A = uncertainty of component A (%)
U_B = uncertainty of component B (%)

Note: all uncertainties are 2-sigma, or at a 95% confidence level

This method of calculation results in an overall uncertainty significantly less than the algebraic sum of the uncertainties of the individual components because it assumes that some degree of offsetting of uncertainties is probable. No changes were made as a result of this comment.

BLM received two comments objecting to the requirement to maintain the differential pressure in the outer 2/3 of calibrated span as it applies to plunger lift and heading wells, and older low volume leases, many producing less than 100 Mcf/day.

We believe the commenters have mis-interpreted the requirements of Paragraph 15. First, Paragraph 15 offers two options as to the lower operating limits of differential pressure: either the outer 2/3 of calibrated span or a differential pressure that will result in an overall meter station uncertainty of ±3%, or better, whichever is less restrictive. In virtually every case we have analyzed, the ±3% uncertainty option is by far the less restrictive option. While the lower limit for differential pressure under this option depends on the equipment being used, it is typically in the range of 5% to 10% of calibrated span rather than 33% of span as in the option described by Paragraph 15(a).

Second, Paragraph 15 only applies to meters measuring more than 100 Mcf/day on a monthly basis, and then only to the majority of the flowing period. Since one of the comments stated that much of the concern is for leases producing less than 100 Mcf/day, these meters would automatically be exempt from either requirement in Paragraph 15.

As far as plunger lift and heading wells flowing more than 100 Mcf/day, the requirement only applies "for the majority of the flowing period". This means that transducers can usually be spanned to accommodate the differential and static pressure spikes, even if the meter cannot maintain the required ±3% uncertainty when the differential or static pressure decline towards the end of the plunger or heading cycle. Documentation for the uncertainty calculator used to determine overall measurement uncertainty recommends entering flow-weighted averages for differential and static pressure as these reasonably represent conditions during the majority of the flowing period. No changes to the NTL were made as a result of these comments.

Two comments expressed concern that there are no industry-accepted methods with which to calculate uncertainty and that the determination of meter uncertainty is subjective. We do not agree with these comments regarding the lack of industry methods to calculate uncertainty. On the contrary, API 14.3.1 includes an entire 11-page section (1.12) on recommended methods for calculating overall measurement uncertainty, including several sample calculations.

We do agree that there is some level of subjectivity in calculating uncertainty, as there is with most calculations. For this reason, BLM had an uncertainty calculator developed that not only allows a quick calculation of uncertainty at the field level, but also provides a consistent and objective means for the calculation. The uncertainty calculator uses the methods described in API 14.3.1.12 as its basis and also includes comprehensive installation effects research conducted by a multitude of flow labs as well as statistical analyses of ambient temperature changes in selected cities across the U.S. The calculator has been available for free public downloading (www.ceesi.com) and review since May, 2007, comes with complete documentation of the methods and calculations used, and is continuously open for comment. To date, very few comments specific to the calculation methodology have been received from industry and for those comments that have been received, changes to the calculator have been made to address concerns. In summary, we believe that the calculation of uncertainty has a sound technical basis and provides a practical alternative to assigning arbitrary operational limits to differential and static pressure transducers. Therefore, no changes were made based on the comment.

One comment expressed a concern that Paragraph 15 is highly restrictive which would add to operating costs and recommended that the requirement be dropped altogether. We do not feel that the uncertainty requirement is overly restrictive when compared to existing industry standards. For example, current requirements in API 21.1.8.1 state that:

> *"the electronic flow measurement system (flow computer and transducers) shall be capable of a performance uncertainty…of ±1% of flow over the expected range of operating temperatures and pressures for the installation."*

To demonstrate the restrictiveness of the NTL requirement versus the API requirement, we ran two tests, one using a self-contained EFC with differential and static pressure transducers rated at ±0.20% of calibrated span, and one using differential and static pressure transducers rated at ±0.05% of calibrated span. The results of the test are as follows:

DP/SP Transducer Reference Accuracy (% of span)	Minimum allowable DP or SP reading (% of span)	
	New Mexico NTL (3% overall measurement uncertainty)	API 21.1.8.6 (1% for flow computer & transducers)
0.20	11	46
0.05	3	15

From the above table, it is clear that this NTL is far less restrictive than existing requirements under API 21.1. For example, the EFC with transducers having a reference accuracy of ±0.20% of span can operate down to 11% of span and still meet the NTL, Paragraph 15(b), requirement for ±3% overall measurement uncertainty. The same EFC could only operate down to 46% of span according to the API 21.1 requirement.

In summary, we do not believe that Paragraph 15(b) is overly restrictive. We feel that using overall measurement uncertainty as a performance-based requirement results in a consistent, objective, and fair method by which all measurement systems can be regulated. Therefore, no changes were made as a result of this comment.

One comment asked how this requirement would increase BLM's gas flow measurement accuracy in relation to current requirements or industry standards. As described above, current requirements in API 21.1 are actually more restrictive than the requirements of this paragraph. However, the requirement in API 21.1 only addresses the flow computer and transducers and does not take into account the primary device or the gas analysis. Therefore, even if a meter were in compliance with the API 21.1 requirements, there is still no control on overall measurement uncertainty. Onshore Order 5 sets the operating limits of chart recorders at the outer 2/3 of the chart range. It is unclear how this requirement applied to EFCs. Prior to the implantation of this NTL, some offices were enforcing the outer 2/3 rule on EFCs which is much more restrictive than the requirements in Paragraph 15(b). Other offices did not believe the outer 2/3 requirement applied to EFCs because the language in Onshore Order 5 refers specifically to “pens”. In this case there was no restriction on where the EFC could operate and that often resulted in transducers operating at a very low percentage of span and very high uncertainty. No changes were made to the NTL as a result of this comment (and none were requested).

Several comments objected to the higher operating costs that would result from this requirement, although no specifics were given as to what the higher operating would result from. We do not believe that this requirement will result in significantly higher operating costs. Meters measuring 100 Mcf/day or less are automatically exempt from this requirement. For meters measuring more than 100 Mcf/day, uncertainty can often be brought into compliance by installing a smaller orifice plate, re-spanning the transducers, or relocating the meters, none of which is particularly costly. No changes to the NTL were made as a result of these comments.