SUMMARY: This document contains corrections to the proposed regulations which were published Friday, July 5, 1996 (61 FR 35158). The proposed rule amends regulations governing Courts of Indian Offenses.

DATES: Comments must be received on or before March 28, 1997.

ADDRESSES: Comments are to be mailed to Bettie Rushing, Office of Tribal Services, Bureau of Indian Affairs, 1849 C Street, NW, MS 4641–MIB, Washington, DC 20240; or, hand delivered to Room 4641 at the same address.

FOR FURTHER INFORMATION CONTACT: Bettie Rushing, Bureau of Indian Affairs (202) 208–4400.

SUPPLEMENTARY INFORMATION:

Background

The proposed rule that is the subject of these corrections supersedes 25 CFR 11.100(a) and affects those tribes that have exercised their inherent sovereignty by removing the names of those tribes from the list of Courts of Indian Offenses.

The Assistant Secretary-Indian Affairs, or her designee, has received law and order codes adopted by the Lovelock Paiute Tribe of Nevada, the Absentee Shawnee Tribe of Indians of Oklahoma, the Cheyenne-Arapaho Tribes of Oklahoma, the Citizen Potawatomi Nation, the Iowa Tribe of Oklahoma, the Kaw Nation, the Kickapoo Tribe of Oklahoma, the Otoe-Missouria Tribe of Indians, the Pawnee Indian Tribe of Oklahoma, and the Osage Indian Nation (except those matters involving the Osage mineral estate) in accordance with their constitutions and by-laws and approved by the appropriate bureau official. The Assistant Secretary-Indian Affairs recognizes that these courts were established in accordance with the tribes' constitutions and by-laws.

Inclusion in § 11.100, Where are Courts of Indian Offenses established?, does not defeat the inherent sovereignty of a tribe to establish tribal courts and exercise jurisdiction under tribal law. Tillett v. Lujan, 931 F.2d 636, 640 (10th Cir. 1991) (CFR courts ''retain some characteristics of an agency of the federal government'' but they ''also function as tribal courts''); Combrink v. Allen, 20 Indian L. Rep. 6029, 6030 (Ct. Ind. App., Tonkawa, Mar. 5, 1993) (CFR court is a ''federally administered tribal court''); Ponca Tribal Election Board v. Snake, 17 Indian L. Rep. 6085, 6088 (Ct. Ind. App., Ponca, Nov. 10, 1988) (''The Courts of Indian Offenses act as tribal courts since they are exercising the sovereign authority of the tribe for which the court sits.''). Such exercise of inherent sovereignty and the establishment of tribal courts shall comply with the requirements in 25 CFR 11.100(c).

Need for Correction

As published, the proposed rule contains errors which may prove to be misleading and are in need of clarification.

Correction of Publication

Accordingly, the publication on July 5, 1996 of the proposed regulations, which were the subject of FR Doc. 96–16039, is corrected as follows:

§ 11.100 [Corrected]

1. On page 35159 in the third column and on page 35160 in the first column paragraph (a) is corrected to read as follows:

§ 11.100 Where are Courts of Indian Offenses established?

(a) Unless indicated otherwise in this title, the regulations in this part apply to the Indian country (as defined in 18 U.S.C. 1151) occupied by the following tribes:

(1) Red Lake Band of Chippewa Indians (Minnesota).

(2) Confederated Tribes of the Goshute Reservation (Nevada).

(3) Te-Moak Band of Western Shoshone Indians (Nevada).

(4) Yomba Shoshone Tribe (Nevada).

(5) Kootenai Tribe (Idaho).

(6) Shoalwater Bay Tribe (Washington).

(7) Eastern Band of Cherokee Indians (North Carolina).

(8) Ute Mountain Ute Tribe (Colorado).

(9) Quechan Indian Tribe (Arizona) (Except resident members).

(10) Valley Tribe, Yurok Tribe, and Coast Indian Community of California (California Jurisdiction limited to special fishing regulations).

(11) Louisiana Area (includes Coushatta and other tribes located in the State of Louisiana which occupy Indian and which accept the application of this part); Provided that this part shall not apply to any Louisiana tribe other than the Coushatta Tribe until notice of such application has been published in the Federal Register.

(12) For the following tribes located in the former Indian Territory (Oklahoma):

(i) Chickasaw Nation.

(ii) Choctaw Nation.

(iii) Thlopthlocco Tribal Town.

(iv) Seminole Nation.

(v) Eastern Shawnee Tribe.

(vi) Miami Tribe.

(vii) Modoc Tribe.

(viii) Ottawa Tribe.

(ix) Peoria Tribe.

(x) Quapaw Tribe.

(xi) Wyandotte Tribe.

(xii) Seneca-Cayuga Tribe.

(xiii) Osage Tribe (Limited to mineral estate matters).

* * * * *

Dated: February 14, 1997.

Ada E. Deer,

Assistant Secretary—Indian Affairs.

[FR Doc. 97–4686 Filed 2–25–97; 8:45 am]

BILLING CODE 4310–22–P

Minerals Management Service

30 CFR Part 250

RIN 1010–AB97

Oil and Gas Production Measurement, Surface Commingling, and Security

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Proposed rule.

SUMMARY: This proposed rule would amend MMS regulations governing oil and gas operations in the Outer Continental Shelf (OCS) to update production measurement and surface commingling requirements. The MMS needs this rule to help ensure that gas produced in the OCS is accurately measured and reported.

DATES: MMS will consider all comments received by May 27, 1997. We will begin reviewing comments at that time and may not fully consider comments we receive after May 27, 1997.

ADDRESSES: Mail or hand-carry comments to the Department of the Interior; Minerals Management Service; Mail Stop 4700; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: Rules Processing Team.

FOR FURTHER INFORMATION CONTACT: Sharon Buffington, Engineering and Research Branch, at (703) 787–1147.

SUPPLEMENTARY INFORMATION: Pipeline and price deregulation and open access to pipelines that occurred in the late 1980's spawned a restructuring of OCS pipeline system operations. Pipeline companies traditionally were merchants buying and selling gas under long-term contracts to only a few well established customers. Under the Federal Energy Regulatory Commission Order 636, pipeline companies operate as common carriers involved in transportation services to a broad spectrum of gas producers, end users, and transportation brokers. Also, the OCS pipeline systems have hundreds of short-term, limited volume contracts, many of which require daily accounting and balance controls.

Because of the restructuring and complexity in pipeline operating systems and the increasing use and value of natural gas, the accuracy and reliability of meters have become even more important to ensuring product accountability and fiscal responsibility. Therefore, industry has initiated production measurement research that resulted in more precise metering and data collection equipment.

Most of the production in the OCS is natural gas and a 1 percent measurement or reporting uncertainty could result in royalty revenue variations of $15 million per year. MMS is responsible for ensuring accurate production measurement and reporting.

The gas measurement and commingling regulations now in effect were based on conditions before deregulation and before the industry began to apply the results of research efforts. Therefore, MMS is proposing to amend the production measurement and commingling regulations. The regulatory revisions proposed in this rule would:

- Reflect current industry technology,
- Form the basis for a gas verification system (GVS),
- Require tracking of gas lost or used on the lease, and
- Clarify the restrictions on surface commingling.

The liquid measurement regulations of 1988 already give the guidance for our liquid verification system. Therefore, MMS is not proposing technical changes to liquid measurement; we are only clarifying the language.

On June 23, 1994, a meeting was held at the Department of the Interior (DOI) in Washington, D.C., to introduce the oil and gas industry to the principles of this rulemaking and the proposed GVS. The participants generally agreed that the regulations on production measurement should be updated to include current industry standards. The main items discussed at the meeting are as follows:

1. If MMS verifies gas production and also conducts audits, it appears that industry is under a double jeopardy. Currently, MMS only audits some OCS gas production. MMS is proposing to supplement the audits by implementing a limited gas verification program that will create a system to quickly check submitted gas production volumes with gas volume statements. MMS will coordinate gas verification and the royalty audit programs.

2. Why does MMS want daily production data on the gas volume statements to verify production reported monthly? While daily production data is easier to obtain from electronically measured data than from chart recorders, it appears that meter owners provide gas producers (lessees) a daily breakout of gas production once a month. Daily production data is the best data to use to verify gas production.

3. How will MMS verify gas that is processed before royalty is calculated? MMS will use the monthly statement that gas plant managers supply to producers instead of the gas volume statement. However, if these statements are not prepared on a daily basis for the month, MMS may ask for additional data from the lessee to verify production.

4. MMS is seeking comments concerning whether you receive monthly gas measurement statements from meter owners that show a daily summary of volumes and quality. If you do not receive the statements, please list how you audit the production records.

5. MMS is seeking comments on the applicable industry standards and practices that we incorporate and exclude. This proposed rule would require that lessees follow the standards listed in 30 CFR 250.1, Documents Incorporated by Reference. MMS published that final rule on November 26, 1996, (61 FR 60019).

6. This proposed rule would require seals only on liquid hydrocarbon royalty installations. However, MMS may also require seals on gas installations in the final rule. Please comment on this proposal.

7. MMS is also seeking comments on the type of records you keep for gas used on the lease, how you record volumes and quality, and how you measure or estimate volumes and quality.

Executive Order (E.O.) 12866

DOI has certified that this proposed rule is not a significant rule under E.O. 12866.

E.O. 12988

DOI has certified to the Office of Management and Budget (OMB) that the rule meets the applicable reform standards provided in sections 3(a) and 3(b)(2) of E.O. 12988.

Unfunded Mandates Reform Act of 1995

DOI has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any year on State, local, and tribal governments, or the private sector.

Regulatory Flexibility Act

The DOI has determined that this proposed rule will not have a significant economic effect on a substantial number of small entities.

Paperwork Reduction Act

This proposed rule contains a collection of information which has been submitted to OMB for review and approval under section 3507(d) of the Paperwork Reduction Act of 1995. As part of our continuing effort to reduce paperwork and respondent burden, MMS invites the public and other Federal agencies to comment on any aspect of the reporting burden. Submit your comments to the Office of Information and Regulatory Affairs; OMB; Attention Desk Officer for the Department of the Interior, 725 17th Street NW, Washington, D.C. 20503 (OMB control number 1010–0051). Send a copy of your comments to the Chief, Engineering and Standards Branch; Mail Stop 4700; Minerals Management Service; 381 Elden Street; Herndon, Virginia 20170–4817. You may obtain a copy of the proposed collection of information by contacting the Bureau's Information Collection Clearance Officer at (703) 787–1242.

OMB may make a decision to approve or disapprove this collection of information after 30 days from receipt of our request. Therefore, your comments are best assured of being considered by OMB if OMB receives them within that time period. However, MMS will consider all comments received during the comment period for this notice of proposed rulemaking.

The title of this collection of information is ''30 CFR 250, Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security.'' OMB previously approved it under OMB control number 1010–0051.

The collection of information consists of oil run tickets; proving and calibrations reports; measuring liquid hydrocarbons and gas; applications for surface commingling, and various recordkeeping requirements. The proposed rule would delete some recordkeeping and reporting requirements. it would add the following when required by the Regional Supervisor:

- Gas volume statements,
- Production quality data, and
- Data concerning gas lost or used on the lease.

MMS would use the information to verify production measurements.

Respondents are Federal OCS oil, gas, and sulphur lessees. MMS will receive approximately 2,300 new responses each year. The frequency of submission varies.

MMS estimates the additional annual reporting burden as a result of this rule would be approximately 192 hours (.08 hour per response). We estimate the total annual burden to be 2,615 reporting hours and 2,429 recordkeeping hours. Based on $35 per hour, the total burden hour cost to respondents is estimated to be $176,540.

In calculating the burden, MMS assumed that respondents perform many of the requirements and maintain records in the normal course of their activities. MMS considers these to be usual and customary and did not include them in the burden estimates. Commenters are invited to provide information if they disagree with this assumption and they should tell us what are the burden hours and costs imposed by this collection of information.

MMS will summarize written responses to this notice and address them in the final rule. All comments will become a matter of public record.

1. MMS specifically solicits comments on the following questions:

(a) Is the proposed collection of information necessary for the proper performance of MMS's functions, and will it be useful?

(b) Are the estimates of the burden hours of the proposed collection reasonable?

(c) Do you have any suggestions that would enhance the quality, clarity, or usefulness of the information to be collected?

(d) Is there a way to minimize the information collection burden on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other forms of information technology?

2. In addition, the Paperwork Reduction Act of 1995 requires agencies to estimate the total annual cost burden to respondents or recordkeepers resulting from the collection of information. MMS needs your comments on this item. Your response should split the cost estimate into two components:

(a) Total capital and startup cost and

(b) Annual operation, maintenance, and purchase of services.

Your estimates should consider the costs to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and startup costs include, among other items, computers and software you purchase to prepare for collecting information; monitoring, sampling, drilling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: Before October 1, 1995; to comply with requirements not associated with the information collection; for reasons other than to provide information or keep records for the Government; or as part of customary and usual business or private practices.

The Paperwork Reduction Act of 1995 provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Takings Implication Assessment

DOI certifies that the proposed rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, a Takings Implication Assessment need not be prepared pursuant to E.O. 12630, Government Action and Interference with Constitutionally Protected Property Rights.

National Environmental Policy Act

DOI determined that this rulemaking does not constitute a major Federal action significantly affecting quality of the human environment; therefore, an Environmental Impact Statement is not required.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Natural gas, Petroleum, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Dated: December 30, 1996.

Bob Armstrong,

Assistant Secretary, Land and Minerals Management.

For the reasons in the preamble, the Minerals Management Service (MMS) proposes to amend 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

1. The authority citation for part 250 continues to read as follows:

Authority: 43 U.S.C. 1334.

2. Subpart L is revised to read as follows:

Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security

Sec.

Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security

§ 250.180 Question Index Table

The table in this section lists questions concerning Oil and Gas Production Measurement, Surface Commingling, and Security and the location of the answers.

Frequently asked questions	CFR citation
1. What are the requirements for measuring liquid hydrocarbons?	§ 250.182 (a).
2. What are the requirements for liquid hydrocarbon royalty meters?	§ 250.182 (b).
3. What are the requirements for run tickets?	§ 250.182 (c).
4. What are the requirements for liquid hydrocarbon royalty meter provings?	§ 250.182 (d).
5. What are the requirements for a master meter and its calibration?	§ 250.182 (e).
6. What are the requirements for calibrating mechanical-displacement provers and tank provers?	§ 250.182 (f).
7. What correction factors must a lessee account for when calibrating meters with a mechanical displacement prover, tank provers or master meter?.	§ 250.182 (g).
8. What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?	§ 250.182 (h).
9. Under what circumstances does MMS consider that a liquid hydrocarbon royalty meter failed and what must a lessee do?	§ 250.182 (i).

Frequently asked questions	CFR citation
10. How must a lessee correct gross liquid hydrocarbon volumes measured under nonstandard conditions?	§ 250.182 (j).
11. What are the requirements for liquid hydrocarbon allocation meters?	§ 250.182 (k).
12. What are the requirements for tank facilities designated as a royalty point?	§ 250.182 (l).
13. To which meters do MMS requirements for gas measurement apply?	§ 250.183 (a).
14. What are the requirements for measuring gas?	§ 250.183 (b).
15. What are the requirements for gas meter calibrations?	§ 250.183 (c).
16. What must a lessee do if a gas meter is malfunctioning?	§ 250.183 (d).
17. What are the requirements when natural gas from a Federal lease is delivered to a gas plant?	§ 250.183 (e).
18. What are the requirements when commingling production at the surface?	§ 250.184 (a).
19. What are the requirements for a well test used for allocation?	§ 250.184 (b).
20. What are the requirements for site security?	§ 250.185 (a).
21. What are the requirements for using seals?	§ 250.185 (b).
22. What are the requirements for measuring gas lost or used on a lease?	§ 250.186.

§ 250.181 Definitions for subpart L.

Terms used in Subpart L have the following meaning:

Allocation meter means a meter whose volume measurement substantiates which portion of the volume measured by a royalty meter is attributable to a particular lease, unit, well, or other measurement point.

API MPMS means the American Petroleum Institute's Manual of Petroleum Measurement Standards.

British Thermal Unit (Btu) means the amount of heat needed to raise the temperature of one pound of water by 1 degree Fahrenheit (1°F) at standard atmospheric pressure.

Calibration means the adjustment or standardization of a measuring instrument to yield precise data.

Fractional Analysis means separating mixtures into identifiable components expressed in mole percent.

Gas meter means an approved meter that measures natural gas and upon which MMS bases royalty and/or allocation volumes.

Gas processing plant means an installation for processing natural gas to remove impurities and recover natural gas liquids (NGL's) and other products. The NGL's are reported as the sum of the products (ethane, propane, butane, and natural gasoline) on the report of sales and royalty remittance. Products like nitrogen, sulphur, carbon dioxide and helium are reported separately.

Gas processing plant statement means a monthly statement showing the volume and quality of the inlet gas stream and the plant products recovered during the period, volume of deductible plant fuel, and the allocation of plant products to the sources of the inlet stream.

Gas royalty meter malfunction means an error in the gas measurement device that exceeds manufacturers specifications.

Gas volume statement means a document prepared by the owner of a gas meter that identifies the volume of natural gas measured by the meter. The statement contains information such as pressure base, temperature base, and volumetric data in a thousand cubic feet (Mcf) and quality data in gross Btu's per cubic foot.

Liquid hydrocarbons (free liquids) mean a mixture of hydrocarbons produced in liquid form after passing through surface separating facilities.

Malfunction factor means a liquid hydrocarbon royalty meter factor that differs from the previous meter factor by an amount greater than 0.0025.

Natural gas means all components of a whole natural gas stream which pass a meter in vapor phase at the measurement point.

Natural gas liquids (NGL's) mean components of natural gas that are liquefied from the whole gas stream and extracted in gas processing plants.

Operating meter means a meter that is used for measurement at any time during the month. A meter must be proved or calibrated only if it is an operating meter.

Pressure base means the pressure at which gas volumes are reported. The standard pressure base for converting measured volumes to standard volumes is 14.73 pounds per square inch absolute (psia).

Prove means to determine the accuracy of a meter, usually by running a known quantity (or quantities) of hydrocarbon through the meter at a known temperature and pressure while recording the meter volume registration.

Retrograde condensate means liquid hydrocarbons that drop out of the separated gas stream at any point prior to entering a gas processing plant, but after the facility measurement point.

Royalty meter means an approved meter that measures natural gas or liquid hydrocarbons and upon which MMS bases royalty volumes.

Run ticket means the invoice for liquid hydrocarbons measured at a royalty point.

Sales meter means a meter at which custody transfer takes place (not necessarily a royalty meter).

Seal means a device or approved method used to prevent tampering with measurement facility components.

Standard conditions means 14.73 pounds per square inch absolute (psia) and 60° F.

Surface commingling means the surface mixing of production from two or more leases or units prior to measurement for royalty purposes.

Temperature base means the temperature at which gas volumes are reported. The standard temperature base for use in converting measured volumes to standard volumes is 60° F.

You or your means the lessee or contractor engaged in operations in the Outer Continental Shelf (OCS).

§ 250.182 Liquid hydrocarbon measurement.

(a) *What are the requirements for measuring liquid hydrocarbons?* Lessees must:

(1) Commence liquid hydrocarbon production or make changes to previously approved measurement procedures only after the Regional Supervisor has approved the liquid hydrocarbon application or changes to an existing approval;

(2) Use measurement equipment that will accurately measure the liquid hydrocarbons produced from a lease or unit;

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS as referenced in 30 CFR 250.1 when obtaining net standard volume and associated measurement parameters; and

(4) When requested by the Regional Supervisor, determine the retrograde condensate volume and allocate it back to the individual leases and/or units and wells.

(b) *What are the requirements for liquid hydrocarbon royalty meters?* Lessees must:

(1) Ensure that the royalty meter facilities include the following components (or other MMS-approved

components) which must be compatible with their connected systems:

(i) A positive-displacement meter equipped with a nonreset totalizer;

(ii) A mechanical displacement prover, a master meter, a calibrated tank prover;

(iii) A proportional-to-flow sampling device pulsed by the meter output; and

(iv) A temperature measurement or temperature compensation device.

(2) Ensure that the royalty meter facilities accomplish the following:

(i) Prevent flow reversal through the meter;

(ii) Protect meters subjected to pressure pulsations or surges;

(iii) Prevent the meter from shock pressures greater than the maximum working pressure; and

(iv) Prevent meter bypassing.

(3) Maintain royalty meter facilities to ensure the following:

(i) Meters operate within the gravity range specified by the manufacturer;

(ii) Meters operate within the manufacturer's specifications for maximum and minimum flow rate for linear accuracy; and

(iii) Meters are reproven when changes in metering conditions affect the meters performance such as changes in pressure, temperature, density (water content), viscosity, pressure, and flow rate.

(4) Ensure that sampling devices conform to the following:

(i) The sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve;

(ii) The sample container is vapor-tight and includes a mixing device to allow complete mixing of the sample before removal from the container; and

(iii) The sample probe is in the center of the flow piping in a vertical run and is located at least three pipe diameters downstream of any pipe fitting within a region of turbulent flow.

(c) *What are the requirements for run tickets?* Lessees must:

(1) Send all run tickets pulled and/or completed to the Regional Supervisor within 15 days following the end of the month;

(2) Pull a run ticket when establishing the monthly meter factor or a malfunction meter factor. Send the Regional Supervisor a copy of this run ticket; and

(3) Ensure that run tickets clearly identify all observed data, all correction factors not included in the meter factor, the net standard volume, and all calculations and factors.

(d) *What are the requirements for liquid hydrocarbon royalty meter provings*? Lessees must:

(1) Permit MMS representatives to witness regularly scheduled provings or any proving requested by the Regional Supervisor;

(2) Ensure that the integrity of the prover calibration is traceable to test measures certified by the National Institute of Standards and Technology;

(3) Prove each operating royalty meter to determine the meter factor during each month but the time between meter factor determinations must not exceed 42 days; and

(4) Submit copies of all meter proving reports for royalty meters to the Regional Supervisor monthly within 15 days after the end of the month.

(e) *What are the requirements for a master meter and its calibration*? Lessees must:

(1) Calibrate the master meter to obtain a meter factor before using it to determine operating meter factors;

(2) Use a fluid of similar gravity, viscosity, temperature, and flow rate as the liquid hydrocarbons that flow through the operating meter to calibrate the master meter;

(3) Calibrate the master meter during each month but the time between calibrations must not exceed 42 days;

(4) Calibrate the master meter by recording runs until the results of two consecutive runs (if a tank prover is used) or five out of six consecutive runs (if a mechanical-displacement prover is used) produce maximum meter factor differences of 0.0002. Lessees must use the average of the two (or the five) runs that produced acceptable results to compute the master meter factor; and

(5) Install the master meter upstream of any back-pressure or reverse flow check valves associated with the operating meter. However, you may install master meters either upstream or downstream of the operating meter.

(6) Keep a copy of the master meter proving report at your field location for 2 years.

(f) *What are the requirements for calibrating mechanical-displacement provers and tank provers*? Lessees must:

(1) Calibrate mechanical-displacement provers and tank provers at least once every 5 years according to the API MPMS as referenced in 30 CFR 250.1; and

(2) Submit a copy of each calibration report to the Regional Supervisor within 15 days after the calibration.

(g) *What correction factors must a lessee account for when calibrating meters with a mechanical-displacement prover, tank prover, or master meter*? Use the following correction factors from the API MPMS as referenced in 30 CFR 250.1:

(1) The change in prover volume due to pressure in the steel pipe (Cps);

(2) The change in volume of the test liquid with the change in temperature (Ctl);

(3) The change in prover volume due to the change in temperature (Cts); and

(4) The change in volume of the test liquid with the change in pressure (Cpl).

(h) *What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons*?

(1) If you use a mechanical-displacement prover, you must record proof runs until five out of six consecutive runs produce a maximum difference between individual runs of .0005. You must use the average of the five runs to compute the meter factor.

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a maximum total meter factor difference of 0.0005. The volume of each run must be at least 10 percent of the hourly rated capacity of the operating meter. You must use the average of the three runs to compute the meter factor.

(3) If you use a tank prover, you must record proof funs until two consecutive runs produce a maximum meter factor difference of .05 percent of the tank prover volume. You must use the average of the two consecutive runs to compute the meter factor.

(4) You must apply meter factors that are within tolerance starting with the date of the proving.

(i) *Under what circumstances does MMS consider that a liquid hydrocarbon royalty meter failed and what must a lessee do*?

(1) If the difference between the meter factor and the previous factor exceeds 0.0025 it is a malfunction factor and lessees must do the following:

(i) Remove the meter from service and check it for damage and/or wear;

(ii) Adjust it and/or repair it, and reprove it;

(iii) Apply the average of the malfunction factor and the previous factor to the production measured through the meter between the date of the previous factor and the date of the malfunction factor; and

(iv) Show all appropriate remarks regarding subsequent repairs and/or adjustments on the proving report.

(2) If a meter fails to register production the lessee must do the following:

(i) Remove the meter from service, repair and reprove it;

(ii) Apply the previous meter factor to the production run between the date of that factor and the date of the failure; and

(iii) Estimate unregistered production by the best possible means and report it as estimated production on the proving report.

(3) If the results of a royalty meter proving exceed the run tolerance criteria and all measures excluding the adjustment and/or repair of the meter can't bring results within tolerance the lessees must:

(i) Establish a factor using proving results made before any adjustment and/or repair of the meter; and

(ii) Treat the established factor like a malfunction factor [See paragraph (i)(1) of this section].

(j) *How must a lessee correct gross liquid hydrocarbon volumes measured under nonstandard condition?*

(1) Calculate Cpl factors into the meter factor or list and apply them on the appropriate run ticket.

(2) List the Ctl factors on the appropriate run ticket when the meter is not automatically temperature compensated.

(k) *What are the requirements for liquid hydrocarbon allocation meters?* Lessees must:

(1) Take samples continuously or daily;

(2) For turbine meters, take the sample proportional to the flow;

(3) Prove allocation meters monthly if they measure 50 or more barrels of oil per day per meter; or

(4) Prove allocation meters quarterly if they measure less than 50 barrels of oil per day per meter;

(5) Keep a copy of the proving reports at the field location for 2 years;

(6) Adjust and reprove the meter if a meter factor differs from the previous meter factor by more than 2 percent and less than 7 percent;

(7) For turbine meters, inspect the meter if a factor differs from the previous meter factor by more than 2 percent and less than 7 percent; and

(8) Repair or replace and reprove the meter if a meter factor differs from the previous meter factor by 7 percent or more.

(l) *What are the requirements for tank facilities designated as a royalty point?* Lessees must:

(1) Equip the tank with a vapor-tight thief hatch, a vent-line valve, and a fill line designed to minimize free fall and splashing;

(2) Submit a complete set of calibration charts (tank tables) to the Regional Supervisor before using the tank for measuring sales;

(3) Obtain the volume and other measurement parameters by using correction factors and procedures in the API MPMS as referenced in 30 CFR 250.1; and

(4) Submit a copy of each run ticket written from tank gaugings to the Regional Supervisor within 15 days after the end of the month.

§ 250.183 Gas measurement

(a) *To which meters do MMS requirements for gas measurement apply?* All OCS gas royalty and allocation meters.

(b) *What are the requirements for measuring gas?* Lessees must:

(1) Commence gas production or make changes to previously approved measurement procedures only after the Regional Supervisor has approved the gas measurement application or changes to an existing approval.

(2) Design, install, use, maintain, and test measurement equipment to ensure accurate and complete measurement. You must follow the recommendations in API MPMS (referenced in 30 CFR 250.1).

(3) Ensure that the measurement components are compatible with their connected systems.

(4) Equip the meter with a chart or electronic data recorder. Electronic data recorders must be capable of displaying real-time data during MMS inspections.

(5) Use continuous on-line chromatographic analyzers or sampling ports upstream or downstream of the meter. Take a sample at least once each calendar month but intervals must not exceed 42 days.

(6) Ensure that standard conditions for reporting gross heating value are at a base temperature of 60° F and at a base pressure of 14.73 pounds per square inch absolute (psia).

(7) When requested by the Regional Supervisor, submit gas volume statements for each requested month's gas sales. Show whether gas volumes and gross Btu heating value are reported at saturated or unsaturated conditions.

(8) When requested by the Regional Supervisor, provide any data necessary for gas volume and quality calculations.

(c) *What are the requirements for gas meter calibrations?* Lessees must:

(1) Calibrate meters monthly but not exceed 42 days between calibrations.

(2) Following a meter calibration, adjust the meter equipment (if necessary) by using the manufacturer's specifications.

(3) For positive displacement or turbine meters, conduct calibrations at the average hourly rate of flow since the last calibration.

(4) Retain calibration test data at the field location for 2 years and send the data to the Regional Supervisor upon request.

(5) Permit MMS representatives to witness regularly scheduled calibrations and any calibration requested by the Regional Supervisor.

(d) *What must a lessee do if a gas meter is malfunctioning?*

(1) If a gas meter is malfunctioning, adjust the meter to function properly or remove it from service and replace it.

(2) Correct the volumes to the last acceptable calibration as follows:

(i) If the duration of the error can be determined, calculate the volume adjustment for that period. The MMS does not require retroactive volume adjustments for allocation beyond 21 days; or

(ii) If the duration of the error can't be determined, apply the volume adjustment to one-half of the time elapsed since the last calibration or 21 days, whichever is less.

(e) *What are the requirements when natural gas from a Federal lease is delivered to a gas plant?*

(1) Lessees must provide the following to the Regional Supervisor upon request:

(i) The gas processing plant statement;

(ii) A gas volume statement for each of the lessee's meter facility sites that contribute natural gas to the processing plant; and

(iii) Composite fractional analyses and gross heating values.

(2) MMS may inspect the measurement and sampling equipment of natural gas processing plants that process Federal production.

§ 250.184 Surface commingling.

(a) *What are the requirements when commingling production at the surface? Lessees must:*

(1) Commence commingling of production only after the Regional Supervisor has approved the commingling and the method of measurement.

(2) Submit an application containing the following information:

(i) The method of allocation measurement and processing, if applicable;

(ii) The manner of entry into the commingled system; and

(iii) Any other information that the Regional Supervisor requests.

(3) Submit any changes to an approved commingling application to the Regional Supervisor for approval.

(4) Upon the request of the Regional Supervisor, lessees who deliver natural gas into a commingled system of both Federal and non-Federal production must provide volumetric and fractional analyses on the non-Federal gas through the designated system operator. If a lessees fails to provide that data, MMS will not permit the lessee to deliver Federal gas into the commingled system.

(b) *What are the requirements for a well test used for allocation?* Lessees must:

(1) Conduct a well test at least once every 2 months unless the Regional Supervisor approved a different frequency;

(2) Follow the well test procedures in § 250.173; and

(3) Retain the well test data at the field location for 2 years.

§ 250.185 Site Security.

(a) *What are the requirements for site security?* Lessees must:

(1) Protect Federal production against production loss or theft;

(2) Post a sign at each storage tank that MMS uses to determine royalty. The sign must contain the name of the facility operator, the size of the tank, and the tank number;

(3) Not bypass MMS-approved liquid hydrocarbon royalty meters and tanks; and

(4) Report the following to the Regional Supervisor as soon as possible, but no later than the next business day after discovery:

(i) Theft or mishandling of production;

(ii) Tampering or bypassing of meter or prover devices; and

(iii) Falsifying production measurements.

(b) *What are the requirements for using seals?* Lessees must:

(1) Seal the following components of liquid hydrocarbon royalty installations to ensure that tampering cannot occur without destroying the seal:

(i) Meter stack component connections from the base of the stack to the register;

(ii) Sampling systems including packing device, fittings, chains, sight glass, and container lid;

(iii) Temperature and gravity compensation device components;

(iv) All valves on lines leaving an oil storage tank including load-out line valves, drain-line valves, and connection-line valves between royalty and non-royalty tanks; and

(v) Any additional components required by the Regional Supervisor.

(2) Number and track the seals and keep the record at the field location for 2 years; and

(3) Make the record of seals available for MMS inspection.

§ 250.186 Measuring gas lost or used on a lease.

What are the requirements for measuring gas lost or used on a lease?

(a) Lessees must either measure or estimate the volume as required by the Regional Supervisor.

(b) If the Regional Supervisor requires you to measure the volume, document the measurement equipment used and include the volume measured.

(c) If the Regional Supervisor requires you to estimate the volume, document the estimating method and the data used and include the volume estimated.

(d) Lessees must keep the volume estimates and documentation at the field location for 2 years.

(e) If the Regional Supervisor requests, lessees must provide copies of the records.

[FR Doc. 97–4534 Filed 2–25–97; 8:45 am]

BILLING CODE 4310–MR–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[WA50–7123b; FRL–5692–9]

Approval and Promulgation of State Implementation Plans: Washington

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving in part, and disapproving in part, and taking no action in part on the Regulations of the Southwest Air Pollution Control Authority (SWAPCA) for the control of air pollution in Clark, Cowlitz, Lewis, Skamania and Wahkiakum Counties, Washington, as revisions to the Washington State Implementation Plan (SIP). These revisions pertain to General Regulations for Air Pollution Sources administered by SWAPCA. In the final rules section of this Federal Register, the EPA is approving the State's SIP revision as a direct final rule without prior proposal because the Agency views this as a noncontroversial revision amendment and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no adverse comments are received in response to this proposed rule, no further activity is contemplated in relation to this rule. If the EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. The EPA will not institute a second comment period on this action.

DATES: Comments on this proposed rule must be received in writing by March 28, 1997.

ADDRESSES: Written comments should be addressed to Montel Livingston, Environmental Protection Specialist (OAQ–107), Office of Air Quality, at the EPA Regional Office listed below. Copies of the documents relevant to this proposed rule are available for public inspection during normal business hours at the following locations. The interested persons wanting to examine these documents should make an appointment with the appropriate office at least 24 hours before the visiting day.

Environmental Protection Agency, Region 10, Office of Air Quality, 1200 6th Avenue, Seattle, WA 98101.

Washington State Department of Ecology, P.O. Box 47600, PV–11, Olympia, WA, 98504–7600.

FOR FURTHER INFORMATION CONTACT: Wayne Elson, Office of Air Quality (OAQ–107), EPA, 1200 6th Avenue, Seattle, WA 98101, (206) 553–1463.

SUPPLEMENTARY INFORMATION: See the information provided in the Direct Final action which is located in the rules section of this Federal Register.

Dated: February 14, 1997.

Charles Findley,

Acting Regional Administrator.

[FR Doc. 97–4660 Filed 2–25–97; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 52 and 64

[CC Docket No. 92–105; FCC 97–51]

The Use of N11 Codes and Other Abbreviated Dialing Arrangements

AGENCY: Federal Communications Commission.

ACTION: Proposed Rule.

SUMMARY: On February 19, 1997, the Commission released a Further Notice of Proposed Rulemaking (*FNPRM*) addressing N11 codes. The FNPRM is intended to obtain comment on the technical feasibility of implementing 711 for access to telecommunications relay services (TRS) and on several other issues related to N11 code administration.

DATES: Comments must be filed on or before March 31, 1997, and reply comments must be filed on or before April 30, 1997.

ADDRESSES: Federal Communications Commission, 1919 M Street, N.W., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Elizabeth Nightingale, Attorney, Network Services Division, Common Carrier Bureau, (202) 418–2352.

SUPPLEMENTARY INFORMATION: This summarizes the Commission's Further Notice of Proposed Rulemaking in the matter of The Use of N11 Codes and Other Abbreviated Dialing