area(s) which result from a CERCLA administrative order, a CERCLA or RCRA consent decree or a court order.

* * * * *

Limitation of Future Contracting Alternate II (Start) (Apr 2004)

* * * * *

(d) During the life of this contract, including any options, the Contractor agrees that unless otherwise authorized by the Contracting Officer:

(1) It will not provide to EPA cleanup services (*e.g.*, Emergency and Rapid Response Services (ERRS) contracts) within the Contractor's START assigned geographical area(s), either as a prime Contractor, subcontractor, or consultant.

(2) Unless an individual design for the site has been prepared by a third party, it will not provide to EPA as a prime contractor, subcontractor or consultant any remedial construction services at a site where it has performed or plans to perform START work. This clause will not preclude START contractors from performing construction management services under other EPA contracts.

(3) It will be ineligible for award of ERRS type activities contracts for sites within its respective START assigned geographical area(s) which result from a CERCLA administrative order, a CERCLA or RCRA consent decree or a court order.

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Limitation of Future Contracting Alternate III (ESAT) (Apr 2004)

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Limitation of Future Contracting Alternate IV (TES) (Apr 2004)

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Limitation of Future Contracting Alternate V (Headquarters Support) (Apr 2004)

* * * * *

(c) The Contractor, during the life of this contract, will be ineligible to enter into a contract with EPA to perform response action work (*e.g.*, Response Action Contract (RAC), Emergency and Rapid Response Services (ERRS), Superfund Technical Assistance and Removal Team (START), and Enforcement Support Services (ESS) contracts), unless otherwise authorized by the Contracting Officer.

* * * * *

Limitation of Future Contracting Alternate VI (Site Specific) (Apr 2004)

* * * * *

(d) During the life of this contract, including any options, the Contractor agrees that unless otherwise authorized by the Contracting Officer:

(1) It will not provide any Superfund Technical Assistance and Removal Team (START) type activities (*e.g.*, START contracts) to EPA on the site either as a prime contractor, subcontractor, or consultant.

* * * * *

1552.215–76 [Removed and reserved]

■ 10. Remove and reserve section 1552.215–76.

1552.229–70 [Removed and reserved]

■ 11. Remove and reserve section 1552.229–70.

1552.237–73 [Removed and reserved]

■ 12. Remove and reserve section 1552.237–73.

[FR Doc. 05–21196 Filed 10–24–05; 8:45 am]
BILLING CODE 6560–50–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket No. RSPA–04–16855; Amdt. 192–101 and 195–85]

RIN 2137—AD97

Pipeline Safety: Standards for Direct Assessment of Gas and Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: Under current regulations governing integrity management of gas transmission lines, if an operator uses direct assessment to evaluate corrosion risks, it must carry out the direct assessment according to PHMSA standards. In response to a statutory directive, this Final Rule prescribes similar standards operators must meet when they use direct assessment on certain other onshore gas, hazardous liquid, and carbon dioxide pipelines. PHMSA believes broader application of direct assessment standards will enhance public confidence in the use of direct assessment to assure pipeline safety.

DATES: This Final Rule takes effect November 25, 2005. Incorporation by reference of NACE Standard RP0502–2002 in this rule is approved by the Director of the **Federal Register** as of November 25, 2005.

FOR FURTHER INFORMATION CONTACT: L.M. Furrow by phone at 202–366–4559, by fax at 202–366–4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at *buck.furrow@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

This Final Rule concerns direct assessment, a process of managing the effects of external corrosion, internal corrosion, or stress corrosion cracking on pipelines made primarily of steel or iron. The process involves data collection, indirect inspection, direct examination, and evaluation. Operators use direct assessment not only to find existing corrosion defects but also to prevent future corrosion problems.

Congress recognized the advantages of using direct assessment on U.S. Department of Transportation (DOT) regulated gas, hazardous liquid, and carbon dioxide pipeline facilities. Section 14 of the Pipeline Safety Improvement Act of 2002 (Pub. L. 107–355; Dec. 17, 2002) directs DOT to issue regulations on using internal inspection, pressure testing, and direct assessment to manage the risks to gas pipeline facilities in high consequence areas. In addition, Section 23 directs DOT to issue regulations prescribing standards for inspecting pipeline facilities by direct assessment.

In response to the first statutory directive, Section 14, DOT's Research and Special Programs Administration (RSPA) [1] published regulations in 49 CFR part 192, subpart O, that require operators to follow detailed programs to manage the integrity of gas transmission line segments in high consequence areas. Subpart O also requires an operator electing to use direct assessment in its integrity management program, to carry out the direct assessment according to §§ 192.925, 192.927, and 192.929, as appropriate.[2]

Sections 192.925, 192.927, and 192.929 cross-reference the American Society of Mechanical Engineers' (ASME), ASME B31.8S–2001, ''Managing System Integrity of Gas Pipelines.'' ASME B31.8S–2001 describes a comprehensive process to assess and mitigate the likelihood and consequences of gas pipeline risks. In addition, § 192.925 cross-references a

[1] The Norman Y. Mineta Research and Special Programs Improvement Act (Pub. L. 108–426, 118; November 30, 2004) reorganized RSPA into two new DOT administrations: the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Research and Innovative Technology Administration. RSPA's regulatory authority over pipeline and hazardous materials safety was transferred to PHMSA.

[2] The standard on external corrosion direct assessment § 192.925) requires operators to integrate data on physical characteristics and operating history, conduct indirect aboveground inspections, directly examine pipe surfaces, and evaluate the effectiveness of the assessment process. Under the standard for direct assessment of internal corrosion (§ 192.927), operators must predict locations where electrolytes may accumulate in normally dry-gas pipelines, examine those locations, and validate the assessment process. The standard for direct assessment of stress corrosion cracking (§ 192.929) involves collecting data relevant to stress corrosion cracking, assessing the risk of pipeline segments, and examining and evaluating segments at risk.

NACE International (NACE) standard, NACE Standard RP0502–2002, ''Pipeline External Corrosion Direct Assessment Methodology.'' NACE Standard RP0502–2002 describes a step-by-step process for identifying and addressing external corrosion activity, repairing defects, and taking remedial action. Other parts of § § 192.925, 192.927, and 192.929 ensure operators use appropriate criteria in making direct assessment decisions.

II. Proposed Rules

In response to the second statutory directive, Section 23, PHMSA published a notice of proposed rulemaking (NPRM) (69 FR 61771; Oct. 21, 2004). The NPRM proposed standards for using direct assessment on any onshore gas pipeline made primarily of steel or iron and regulated by 49 CFR part 192 or onshore steel hazardous liquid or carbon dioxide pipeline regulated by 49 CFR part 195. Under proposed § 192.490, if an operator chooses to use direct assessment to evaluate the threat of external corrosion, internal corrosion, or stress corrosion cracking on a regulated onshore gas pipeline, the direct assessment would have to be done according to § § 192.925, 192.927, or 192.929, as appropriate. For regulated hazardous liquid and carbon dioxide pipelines, proposed § 195.588 would require similar action, except compliance with § 192.927 would not be required, because § 192.927 requirements are only suitable for dry gas pipelines.

III. Advisory Committee Recommendations

The Technical Pipeline Safety Standards Committee (TPSSC) and the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) considered the NPRM at meetings in Washington, DC, on December 14 and 15, 2004. The TPSSC, a statutorily mandated advisory committee, advises PHMSA on proposed safety standards and other policies concerning gas pipelines. The THLPSSC is a similar committee that provides advice about hazardous liquid and carbon dioxide pipelines. Each committee has an authorized membership of 15 persons with membership evenly divided between government, industry, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. A transcript of each committee's meeting is available in Docket No. PHMSA–98–4470.

After careful consideration of the NPRM, the THLPSSC voted unanimously to recommend the following: (1) Adopt a single definition of direct assessment for use by hazardous liquid pipeline operators inside and outside high consequence areas; (2) state direct assessment standards directly in part 195, rather than by cross-referencing part 192 standards; (3) consider adopting the consensus standard under development by NACE for direct assessment of stress corrosion cracking; and (4) amend the integrity management rule (§ 195.452) to allow use of direct assessment without prior notice.

As a result of its deliberation, the TPSSC voted unanimously that proposed § 192.490 should not be applied to gas distribution lines. It also voted unanimously that the Final Rule should distinguish direct assessment from similar methods of assessing corrosion. Such a distinction would identify situations where similar methods of addressing corrosion are appropriate but are not regulated under the proposed direct assessment standard.

IV. Disposition of Comments and Advisory Committee Recommendations on Proposed Rules

We received written comments on the proposed rules from 19 sources. These sources are categorized as follows:

State pipeline safety agency	Pennsylvania Public Utility Commission.
Gas pipeline operators	Duke Energy Gas Transmission (Duke), El Paso Corporation (El Paso), Nicor Gas (Nicor), NiSource Corporate Services Company (Nisource), Pacific Gas & Electric Company (PG&E), Paiute Pipeline Company (Paiute), Puget Sound Energy (Puget), Southwest Gas Corporation (SWGas).
Gas pipeline trade associations	American Public Gas Association (APGA), American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), Northeast Gas Association (NGA).
Gas pipeline industry committee	Gas Piping Technology Committee (GPTC).
Hazardous liquid pipeline trade associations	American Petroleum Institute (API), Association of Oil Pipe Lines (AOPL).
Nonprofit organizations	Cook Inlet Regional Citizens Advisory Council, Pipeline Safety Trust
Consultant	Glen F. Armstrong.

Only one commenter, the Cook Inlet Regional Citizens Advisory Council (Council), created by the Oil Pollution Act of 1990, supported the proposed rules without change. The Council welcomed the additional Federal standards because of the need to control pipeline corrosion. The remaining commenters' issues are stated below along with our disposition of those issues and the advisory committee's recommendations.

Is this rulemaking necessary? AGA, Duke, El Paso, GPTC, INGAA, NiSource, and Puget claimed the integrity management regulations for gas transmission lines (subpart O of part 192) satisfy the statutory directive to prescribe direct assessment standards. Taking a similar position, AOPL and API contended that Congress did not intend direct assessment standards to apply outside integrity management regulations. To support this position, these commenters stated that Congress did not require operators to use direct assessment on pipelines outside integrity management regulations. They also pointed out that direct assessment was developed for use in integrity management programs.

Because the legislative history does not support the commenter's argument that direct assessment standards should apply only to pipelines subject to integrity management rules, PHMSA believes this rulemaking is necessary. It is reasonable to conclude Congress did not intend to restrict direct assessment standards to pipelines covered by integrity management regulations. Unlike the first statutory directive concerning direct assessment, which applies only to pipeline facilities in high consequence areas, the second directive applies to pipeline facilities regardless of location. Also, the first and second directives appear in separate sections of the statute (Sections 14 and 23 of Pub. L. 107–355), with no apparent connection. Had Congress wanted to restrict direct assessment standards to pipelines covered by integrity management regulations, it could have expressly linked the second directive to the first or included the second directive in the same section as the first.

Is proposed § 192.490 appropriate for gas distribution lines? AGA, APGA, Duke, El Paso, GPTC, INGAA, NGA, Nicor, NiSource, Paiute, and PG&E argued direct assessment was developed for gas transmission integrity management and has not been shown to be appropriate for gas distribution lines. They said the relevant technical data and experience do not show direct assessment would be effective on gas distribution lines. In addition, some of these commenters thought because gas distribution lines differ from gas transmission lines in design, operation, configuration, and location, direct assessment may be impractical on gas distribution lines. The many aboveground and belowground utility facilities—both in-service and abandoned—were thought to pose significant technical hurdles. The Pennsylvania Public Utility Commission and the Pipeline Safety Trust also questioned the suitability of direct assessment for gas distribution lines.

These comments came as a surprise to PHMSA because the two documents that are the mainstays of the proposed direct assessment standards, ASME B31.8S–2001 and NACE Standard RP0502–2002, can be interpreted to cover gas distribution lines. Each document states that it applies to onshore pipelines. Although neither document defines ''pipeline,'' ASME's B31.8 Code, to which ASME B31.8S–2001 is a supplement, defines ''pipeline'' as ''all parts of physical facilities through which gas moves in transportation.'' And ''transportation of gas'' is defined as the ''gathering, transmission, or distribution of gas.''

No matter how ASME B31.8S–2001 and NACE Standard RP0502–2002 are interpreted, the comments persuaded us that direct assessment, as depicted by these two documents, is not appropriate for gas distribution lines. Both ASME B31.8S–2001 and NACE Standard RP0502–2002, were developed during the rulemaking proceeding on gas transmission integrity management and in furtherance of that proceeding. Consequently, neither document was developed with a focus on gas distribution lines. Furthermore, although both documents apply to pipelines, they do not take full account of gas distribution line features as comments suggest they should to treat gas distribution lines appropriately.

Given these considerations and the TPSSC's unanimous recommendation that we not apply the proposed direct assessment standards to gas distribution lines, we decided to exclude distribution lines from final § 192.490. Removing ''pipeline'' from the proposed wording and adding ''transmission line'' in its place accomplishes this change.

Would the proposed standards discourage the voluntary use of corrosion control methods? AGA, Armstrong, Duke, El Paso, GPTC, INGAA, NGA, Nicor, NiSource, Paiute, PG&E, Puget, and SWGas were concerned the proposed standards (§ § 192.490 and 195.588) would discourage operators from voluntarily using corrosion control methods related to direct assessment on pipelines not subject to the integrity management regulations. Their concern stemmed from the difficulty of recognizing when direct assessment is being used. They said performance of any one of the four steps that constitute direct assessment could imply use of direct assessment and lead to disagreements with government inspectors over whether direct assessment is being used. For example, some commenters said performing a close interval electrical survey resembled the indirect examination step of direct assessment. Others thought examining buried pipe for corrosion could be considered the direct examination step. El Paso, INGAA, Nicor, and Armstrong suggested the Final Rule clarify that operators may use corrosion control methods related to direct assessment without having to meet the proposed direct assessment standards.

We recognize disagreements could arise over whether the use of a corrosion control method is part of the direct assessment process. However, we do not think such disagreements are likely to be serious enough to discourage operators from continuing to use such methods separately from direct assessment. To minimize potential disagreements, operators may explain in their corrosion control procedures the situations in which they use methods related to direct assessment separately from direct assessment.

In view of the commenters' concern, PHMSA has added provisions to final § § 192.490 and 195.588 to clarify application of the direct assessment standards. The statement provides that the direct assessment standards do not apply to methods related to direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process. This change is consistent with the TPSSC's second recommendation.

Are the gas pipeline standards cross-referenced in proposed § 195.588 suitable for hazardous liquid and carbon dioxide pipelines? In their comments on proposed § 195.588, AOPL and API opposed cross-referencing § § 192.925 and 192.929 primarily because these standards refer to ASME B31.8S–2001. They argued ASME B31.8S–2001 was developed for natural gas transmission lines and without the involvement of hazardous liquid pipeline operators. They were also concerned that cross-referencing part 192 gas pipeline standards could lead to misunderstandings by hazardous liquid pipeline operators. The THLPSSC similarly opposed cross-referencing part 192 standards.

In developing the NPRM, we assumed the cross-referenced part 192 standards and their cross-references to ASME B31.8S–2001 would be suitable for hazardous liquid and carbon dioxide pipelines. However, the AOPL and API comments and the THLPSSC's recommendation have caused us to doubt that assumption. In addition, we are concerned that application of the part 192 direct assessment standards to hazardous liquid and carbon dioxide pipelines could present compliance problems. Contributing to this concern is the comment that ASME B31.8S–2001 was not developed with an eye to hazardous liquid pipelines. In fact, paragraph 1.1 of ASME B31.8S–2001 specifically states that the scope of ASME B31.8S–2001 is limited to ''onshore pipeline systems * * * that transport gas.''

Therefore, we decided not to include cross-references to part 192 standards or to ASME B31.8S–2001 in final § 195.588. Instead, final § 195.588 includes a complete statement of direct assessment standards, with cross-references only to NACE Standard RP0502–2002.

Should the integrity management regulations for hazardous liquid and carbon dioxide pipelines allow use of direct assessment without advance notice? The integrity management regulations for hazardous liquid and carbon dioxide pipelines (§ 195.452) prescribe three ways to assess pipeline integrity: internal inspection via a smart pig, pressure testing, and any other technology the operator demonstrates can provide an equivalent understanding of pipe conditions. However, before another technology, such as direct assessment may be used, the operator must notify PHMSA at least 90 days in advance (§ § 195.452(c)(1)(i)(C) and 195.452(j)(5)(iii)).

In contrast to § 195.452, the proposed direct assessment standards do not include a requirement to give 90 days' advance notice as a precondition to using direct assessment. We see no need to propose such a requirement since the current Part 192 direct assessment standards do not require operators to give advance notice before using direct assessment.

In their comments on proposed § 195.588, AOPL and API suggested direct assessment of external corrosion should be listed directly in § 195.452 as a permissible method of integrity assessment. They believe that when external corrosion direct assessment is performed according to NACE Standard RP0502–2002, it is an acceptable use of ''other technology'' for which 90 days advance notice is no longer necessary. As discussed above under Advisory Committee Recommendations, the THLPSSC also favored listing direct assessment directly in § 195.452 as a recognized assessment method that would bypass the 90-day advance notice requirement.

The purpose of the 90 days advance notice requirement in § 195.452 is to provide time for PHMSA and State pipeline safety agencies to review technology other than pigging and pressure testing to learn what information the technology provides about pipe conditions. According to information on a PHMSA Web site (*http://primis.phmsa.dot.gov/iim/notifications.imd*), several operators have submitted notices of their intent to use direct assessment on hazardous liquid or carbon dioxide pipelines. In a majority of cases, there were no PHMSA or State government objections to the use of direct assessment. Objections were raised where the notification lacked information explaining how the direct assessment was to be performed.

When applied to direct assessment, we believe the 90-day advance notice requirement of § 195.452 is no longer useful and is inconsistent with the proposed rules. Direct assessment is now being used under the part 192 integrity management regulations without advance notice. As a result, government inspectors are fully aware of the direct assessment technology and the situations for which it is suited, making advance case-by-case review under § 195.452 unnecessary. In addition, requiring operators to follow prescribed standards when using direct assessment will remove the primary objection previously raised about operators' advance notices—insufficient information to explain the method of assessment. Therefore, we are changing § § 195.452(c)(1)(i)(C) and 195.452(j)(5)(iii) to allow use of direct assessment in accordance with final § 195.588 without 90 days advance notice.

What standard should apply to direct assessment of stress corrosion cracking on hazardous liquid and carbon dioxide pipelines? The NPRM proposed that § 192.929 be the standard for direct assessment of stress corrosion cracking on hazardous liquid and carbon dioxide pipelines. This standard relies largely on cross-references to ASME B31.8S–2001.

Besides their objections to cross-referencing part 192 standards and particularly ASME B31.8S–2001, AOPL and API suggested that we not adopt any standard for the direct assessment of stress corrosion cracking on hazardous liquid pipelines. They said because methods of detecting stress corrosion cracking are developing rapidly, direct assessment may not be the optimum technology for hazardous liquid pipelines. The THLPSSC recommended we consider adopting the consensus standard that NACE International was developing for direct assessment of stress corrosion cracking.

As explained above, we decided not to cross-reference directly or indirectly ASME B31.8S–2001 in final § 195.588, because the document is closely identified with gas pipelines. Consequently, since provisions of ASME B31.8S–2001 are an important part of the proposed stress corrosion standard, we have not included a direct assessment standard for stress corrosion cracking in final § 195.588. As the THLPSSC recommended, we will consider the recently published NACE Standard RP0204–2004, Stress Corrosion Cracking (SCC) Direct Assessment Methodology, for possible future rulemaking action. By removing the proposed cross-reference to § 192.929, final § 195.588 consists of the text of § 192.925 without its cross-references to ASME B31.8S–2001.

V. Editorial Changes

• Final § § 192.490 and 195.588 do not include the proposed phrase ''or to meet any requirement of this Subpart regarding that threat.'' The phrase was used in the proposed rules to draw attention to situations in which operators might choose to use direct assessment. However, the phrase appears to be unnecessary and, according to comments, possibly confusing.

• Final § 192.490 clarifies that ''direct assessment'' means direct assessment as defined in § 192.903.[3] This definition applies to ''direct assessment'' as it is used in subpart O of part 192, including § § 192.925, 192.927, and 192.929—the bases of the proposed direct assessment standards. Also, in final § 192.490, instead of using the proposed term ''ferrous'' to limit pipelines to which the direct assessment standards apply, we used ''made primarily of steel or iron.'' This change removes the possibility of confusion over the meaning of ferrous.

• We added a similar definition of ''direct assessment'' to § 195.553, which contains definitions applicable to subpart H of part 195, including final § 195.588. This addition satisfies the first THLPSSC recommendation. The definition of ''external corrosion direct assessment,'' which was proposed through the cross-reference to § 192.925, is also added to § 195.553.

• In final § 195.588, we substituted ''pipeline segment'' for the terms ''covered segment'' and ''covered pipeline segment'' to avoid the possibility that the definition of these terms in § 192.903—a segment of transmission pipeline located in a high consequence area—would unintentionally constrain the scope of final § 195.588. A footnote resolves a similar problem in final § 192.490.

• Section 192.925(b) provides that if coating damage is detected by external corrosion direct assessment, the operator must integrate that information with data gathered and integrated under certain other requirements (§ § 192.917(b) and 192.917(e)(1)). These other requirements, which involve evaluating and addressing risks besides corrosion, including third-party damage, apply only to gas transmission lines subject to the integrity management regulations in subpart O of part 192. Although the proposed direct assessment standards for other pipelines included cross-references to § 192.925, the NPRM did not address extending § § 192.917(b) and 192.917(e)(1) to pipelines outside subpart O by virtue of the cross-references. The focus of the NPRM was strictly on using direct assessment to evaluate and address corrosion risks. Using direct assessment data to evaluate non-corrosion risks to pipeline integrity was not discussed. So it would be inappropriate to infer that the proposed references to § 192.925 meant that operators who voluntarily use external corrosion direct assessment on pipelines outside subpart O would also have to comply with § § 192.917(b) and 192.917(e)(1). To ensure this possible inference does not affect the Final Rules, final § § 192.490 and 195.588 exclude pipelines outside subpart O from the § 192.925(b) requirement related to integrating coating damage data. Nevertheless, for

[3] Section 192.903 defines ''direct assessment'' as ''an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's intergrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.''

hazardous liquid and carbon dioxide pipelines that are subject to the integrity management regulations in § 195.452, the detection of coating damage is an important factor to consider in the information analysis required by § 195.452(g) and the continual integrity evaluation required by § 195.452(j)(2).

VI. Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures. PHMSA does not consider this rulemaking to be a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of the Final Rule to review. PHMSA also does not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

PHMSA has evaluated the costs and benefits of this Final Rule and a copy of the evaluation is in the docket. The evaluation concludes operators will incur only minimal costs to comply with the Final Rule.

Regulatory Flexibility Act. Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions have a significant economic impact on a substantial number of small entities. Based on the facts available about the anticipated impacts of this rulemaking, I certify that this rulemaking will not have a significant impact on a substantial number of small entities.

Executive Order 13175. PHMSA has analyzed this rulemaking according to the principles and criteria contained in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because the Final Rule will not significantly or uniquely affect the communities of the Indian Tribal Governments nor impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act. Operators have just recently begun to use direct assessment to assess the effects of corrosion on onshore gas transmission lines subject to the integrity management regulations in subpart O of part 192. The use of direct assessment on other pipelines regulated by part 192 or part 195 is voluntary. This Final Rule does not change this voluntary use status. It merely sets standards for performing direct assessment if operators choose to use it.

Pipeline operators covered by the Final Rule who choose to use direct assessment would have to prepare appropriate plans and procedures and keep records as required by Section 7 of *NACE Standard RP0502–2002.* To help estimate the paperwork burden these operators would face, the NPRM invited comments on how many operators plan to use direct assessment voluntarily and what the burden hours and cost would be.

None of the commenters foresaw any voluntary use of direct assessment or commented on the potential paperwork burden. This result was not a surprise, for direct assessment is a new process and so far its use is mostly limited to gas transmission lines subject to subpart O of part 192. Under these circumstances, it is reasonable to expect that few, if any, operators will be affected by the Final Rule. So no net increase in paperwork burdens is likely from this Final Rule. For this reason, we believe that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary.

Unfunded Mandates Reform Act of 1995. This Final Rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rulemaking.

National Environmental Policy Act. PHMSA has analyzed the Final Rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the Final Rule affects only those operators that voluntarily use direct assessment and because it largely involves processes of data collection and evaluation, we have determined that it is unlikely to significantly affect the quality of the human environment. An Environmental Assessment is available for review in the docket.

Executive Order 13132. PHMSA has analyzed the Final Rule according to the principles and criteria contained in Executive Order 13132, ''Federalism.'' No part of the rule (1) has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on State and local governments; or (3) preempts State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211. This Final Rule is not a ''Significant Energy Action'' under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects

49 CFR Part 192

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 195

Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

■ In consideration of the foregoing, PHMSA amends 49 CFR parts 192 and 195 as follows:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

■ 2. Add § 192.490 to read as follows:

§ 192.490 Direct assessment.

Each operator that uses direct assessment as defined in § 192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard [1]
External corrosion	§ 192.925 [2]
Internal corrosion in pipelines that transport dry gas.	§ 192.927
Stress corrosion cracking	§ 192.929

[1] For lines not subject to subpart O of this part, the terms ''covered segment'' and ''covered pipeline segment'' in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2] In § 192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 3. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

■ 4. In § 195.3(c), amend the table of referenced material by adding item G.(2) to read as follows:

§ 195.3 Matter incorporated by reference in whole or in part.

* * * * *

(c) * * *

G. * * * .... (2) NACE Standard RP0502–2002 "Pipeline External Corrosion Direct Assessment Methodology" (2002).	* * * § 195.588

■ 5. Amend § 195.452 as follows:
■ a. Redesignate paragraph (c)(1)(i)(C) as (c)(1)(i)(D);
■ b. Remove "or" from the end of paragraph (c)(1)(i)(B);
■ c. Redesignate paragraph (j)(5)(iii) as (j)(5)(iv);
■ d. Remove "or" from the end of paragraph (j)(5)(ii); and
■ e. Add new paragraphs (c)(1)(i)(C) and (j)(5)(iii) to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(c) * * *

(1) * * *

(i) * * *

(C) External corrosion direct assessment in accordance with § 195.588; or

* * * * *

(j) * * *

(5) * * *

(iii) External corrosion direct assessment in accordance with § 195.588; or

* * * * *

■ 6. In § 195.553, add definitions for "direct assessment" and "external corrosion direct assessment (ECDA)" as follows:

§ 195.553 What special definitions apply to this Subpart?

* * * * *

Direct assessment means an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

* * * * *

External corrosion direct assessment (ECDA) means a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

* * * * *

■ 7. Add § 195.588 to read as follows:

§ 195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) *General.* You must follow the requirements of NACE Standard RP0502–2002 (incorporated by reference, see § 195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment.

(2) *Pre-assessment.* In addition to the requirements in Section 3 of NACE Standard RP0502–2002, the ECDA plan procedures for pre-assessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and

(iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502–2002, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(3) *Indirect examination.* In addition to the requirements in Section 4 of NACE Standard RP0502–2002, the procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:

(A) The known sensitivities of assessment tools;

(B) The procedures for using each tool; and

(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) For each indication identified during the indirect examination, criteria for—

(A) Defining the urgency of excavation and direct examination of the indication; and

(B) Defining the excavation urgency as immediate, scheduled, or monitored; and

(iv) Criteria for scheduling excavations of indications in each urgency level.

(4) *Direct examination.* In addition to the requirements in Section 5 of NACE Standard RP0502–2002, the procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard RP0502–2002 provides guidance for criteria); or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE Standard RP0502–2002 provides guidance for criteria);

(iii) Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis you will reclassify and re-prioritize any of the provisions specified in Section 5.9 of NACE Standard RP0502–2002.

(5) *Post assessment and continuing evaluation.* In addition to the requirements in Section 6 of NACE Standard UP 0502–2002, the procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in

Sections 6.2 and 6.3 of NACE Standard RP0502–2002 (see Appendix D of NACE Standard RP0502–2002).

Issued in Washington, DC, on October 19, 2005.

Brigham A. McCown,

Acting Administrator, PHMSA.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 031015257-3308-02 ; I.D. 101705B]

Fisheries of the Northeastern United States; Atlantic Surfclam and Ocean Quahog Fisheries; Suspension of Minimum Atlantic Surfclam Size Limit for Fishing Year 2006

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; suspension of the Atlantic surfclam minimum size limit.

SUMMARY: NMFS suspends the minimum size limit of 4.75 inches (120 mm) for Atlantic surfclams for the 2006 fishing year. This action is taken under the authority of the implementing regulations for this fishery, which allow for the annual suspension of the minimum size limit based upon set criteria. The intended effect is to relieve the industry from a regulatory burden that is not necessary, as the majority of surfclams harvested are larger than the minimum size limit.

DATES: Effective January 1, 2006, through December 31, 2006.

ADDRESSES: Written inquiries may be sent to Patricia A. Kurkul, Regional Administrator, National Marine Fisheries Service, Northeast Regional Office, One Blackburn Drive, Gloucester, MA 01930–2298.

FOR FURTHER INFORMATION CONTACT: Brian R. Hooker, Fishery Policy Analyst, (978) 281-9220; fax (978) 281–9135.

SUPPLEMENTARY INFORMATION: Section 648.72(c) of the regulations implementing the Fishery Management Plan (FMP) for the Atlantic Surfclam and Ocean Quahog Fisheries allows the Administrator, Northeast Region, NMFS (Regional Administrator) to suspend annually, by publication of a notification in the Federal Register, the minimum size limit for Atlantic surfclams. This action may be taken unless discard, catch, and biological sampling data indicate that 30 percent of the Atlantic surfclam resource is smaller than 4.75 inches (120 mm) and the overall reduced size is not attributable to harvest from beds where growth of the individual clams has been reduced because of density-dependent factors.

At its June 2004 meeting, the Mid-Atlantic Fishery Management Council (Council) voted to recommend that the Regional Administrator suspend the minimum size limit for the 2005, 2006, and 2007 fishing years. In accordance with the provisions of the FMP, the Regional Administrator will publish the suspension of the surfclam minimum size if the proportion of undersized surfclams is under 30 percent of the total surfclam landings for each fishing year.

Commercial surfclam data for 2005 were analyzed to determine the percentage of surfclams that were smaller than the minimum size requirement. The analysis indicated that 6.8 percent of the overall commercial landings were composed of surfclams that were less than 4.75 inches (120 mm). Based on these data, the Regional Administrator adopts the Council's recommendation and suspends the minimum size limit for Atlantic surfclams from January 1, 2006, through December 31, 2006.

Classification

This action is authorized by 50 CFR part 648 and is exempt from review under Executive Order 12866.Authority: 16 U.S.C. 1801 et seq.

Dated: October 20, 2005.

Alan D. Risenhoover,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

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