or between refineries, except as noted in paragraph (d)(1)(iv) of this section.

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[FR Doc. E8–4915 Filed 3–11–08; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 271

[EPA–R08–RCRA–2006–0382; FRL–8541–6]

Colorado: Final Authorization of State Hazardous Waste Management Program Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Colorado has applied to EPA for final authorization of the changes to its hazardous waste program under the Resource Conservation and Recovery Act (RCRA). The EPA proposes to grant final authorization to the hazardous waste program changes submitted by Colorado. In the ''Rules and Regulations'' section of this **Federal Register**, EPA is authorizing the State's program changes as an immediate final rule. EPA did not make a proposal prior to the immediate final rule because we believe these actions are not controversial and do not expect comments to oppose them. We have explained the reasons for this authorization in the preamble to the immediate final rule. Unless we get written comments opposing this authorization during the comment period, the immediate final rule will become effective and the Agency will not take further action on this proposal. If we receive comments that oppose these actions, we will publish a document in the **Federal Register** withdrawing this rule before it takes effect. EPA will then address public comments in a later final rule based on this proposal. Any parties interested in commenting on these actions must do so at this time. EPA may not provide further opportunity for comment.

DATES: Comments must be received on or before April 11, 2008.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–RCRA–2006–0382, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *E-mail: daly.carl@epa.gov*.
- *Fax:* (303) 312–6341.
- *Mail:* Send written comments to Carl Daly, Solid and Hazardous Waste Program, EPA Region 8, Mailcode 8P–HW, 1595 Wynkoop Street, Denver, Colorado 80202–1129.
- *Hand Delivery or Courier:* Deliver your comments to Carl Daly, Solid and Hazardous Waste Program, EPA Region 8, Mailcode 8P–HW, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Such deliveries are only accepted during the Regional Office's normal hours of operation. The public is advised to call in advance to verify the business hours. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–R08–RCRA–2006–0382. EPA's policy is that all comments received will be included in the public docket without change, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov*, or e-mail. The federal web site *http://www.regulations.gov* is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties, and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters or any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm*.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information may not be publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at: EPA Region 8, from 9 a.m. to 4 p.m., 1595 Wynkoop Street, Denver, Colorado, contact: Carl Daly, phone number (303) 312–6416, or the Colorado Department of Public Health and Environment, from 9 a.m. to 4 p.m., 4300 Cherry Creek Drive South, Denver, Colorado 80222–1530, contact: Randy Perila, phone number (303) 692–3364.

FOR FURTHER INFORMATION CONTACT: Carl Daly, Solid and Hazardous Waste Program, U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop Street, Denver, Colorado 80202, (303) 312–6416, *daly.carl@epa.gov*.

SUPPLEMENTARY INFORMATION: For additional information, please see the immediate final rule published in the ''Rules and Regulations'' section of this **Federal Register**.

Dated: February 28, 2008.

Carol Rushin,

Acting Regional Administrator, Region 8.

[FR Doc. E8–4977 Filed 3–11–08; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket ID PHMSA–2005–23447; Notice 2]

RIN 2137–AE25

Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation

ACTION: Notice of proposed rulemaking.

SUMMARY: PHMSA proposes to amend the pipeline safety regulations to prescribe safety requirements for the operation of certain gas transmission pipelines at pressures based on higher stress levels. The result would be an increase of maximum allowable operating pressure (MAOP) over that currently allowed in the regulations. This action would update regulatory standards to reflect improvements in pipeline materials, assessment tools, and maintenance practices, which together have significantly reduced the risk of failure in steel pipeline fabricated and installed over the last twenty-five years. The proposed rule would allow use of an established industry standard for the calculation of

MAOP, but limit application of the standard to pipelines posing a low safety risk based on location, materials, and construction. The proposed rule would generate significant public benefits by boosting the potential capacity and efficiency of pipeline infrastructure, while promoting investment in improved pipe technology and rigorous life-cycle maintenance.

DATES: Anyone interested in filing written comments on the rule proposed in this document must do so by May 12, 2008. PHMSA will consider late filed comments so far as practicable.

ADDRESSES: Comments should reference Docket ID PHMSA–2005–23447 and may be submitted in the following ways:

- *E-Gov Web Site: http://www.regulations.gov.* This site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management System: U.S. Department of Transportation, 1200 New Jersey Avenue, SE., Room W12–140, Washington, DC 20590.
- *Hand Delivery:* DOT Docket Management System; Room W12–140, on the ground floor of the West Building, 1200 New Jersey Avenue, SE., Washington, DC between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: Identify the docket ID, PHMSA–2005–23447, at the beginning of your comments. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *http://www.regulations.gov.*

Note: Comments will be posted without changes or edits to *http://www.regulations.gov* including any personal information provided. Please see the Privacy Act heading in the Regulatory Analyses and Notices section of the Supplemental Information for additional information.

FOR FURTHER INFORMATION CONTACT: For information about this rulemaking, contact Barbara Betsock by phone at (202) 366–4361, by fax at (202) 366–4566, or by e-mail at *barbara.betsock@dot.gov.* For technical information, contact Alan Mayberry by phone at (202) 366–5124, or by e-mail at *alan.mayberry@dot.gov.*

SUPPLEMENTARY INFORMATION:

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A. Purpose of the Rulemaking

The regulatory relief proposed in this rulemaking is made possible by dramatic improvements in pipeline technology and risk controls over the past 25 years. The current standards for calculating maximum allowable operating pressure (MAOP) on gas transmission pipelines were adopted in 1970, in the original pipeline safety regulations promulgated under Federal law. Almost all risk controls on gas transmission pipelines have been strengthened in the intervening years, beginning with the introduction of improved manufacturing, metallurgy, testing, and assessment tools and standards. Pipe manufactured and tested to modern standards is far less likely to contain defects that can grow to failure over time than pipe manufactured and installed a generation ago. Likewise, modern maintenance practices, if consistently followed, significantly reduce the risk that corrosion, or other defects affecting pipeline integrity, will develop in installed pipelines. Most recently, operators' development and implementation of integrity management programs have increased understanding about the condition of pipelines and of how to reduce pipeline risks. In view of these developments, PHMSA believes that certain gas transmission pipelines can be safely and reliably operated at pressures above current Federal pipeline safety design limits. With appropriate conditions and controls, permitting operation at higher pressures will increase energy capacity and efficiency, without diminishing system safety.

PHMSA has granted special permits on a case-by-case basis to allow operation of particular pipeline segments at a higher MAOP than currently allowed under the design requirements. These special permits have been limited to operation in Class 1, 2, and 3 locations and conditioned on demonstrated rigor in the pipeline's design and construction and the operator's performance of additional safety measures. Building on the record developed in the special permit proceedings, PHMSA now proposes to codify the conditions and limitations of the special permits into standards of general applicability.

B. Background

B.1. Current Regulations

The design factor specified in § 192.105 restricts the MAOP of a steel gas transmission pipeline based on stress levels and class location. For most steel pipelines, the MAOP is defined in § 192.619 based on design pressure calculated using a formula, found at § 192.111, that includes the design factor. In sparsely populated Class 1 locations, the design factor specified in § 192.105 restricts the stress level at which a pipeline can be operated to 72 percent of the specified minimum yield strength (SMYS) of the steel. The operating pressures in more populated Class 2 and Class 3 locations are limited to 60 and 50 percent of SMYS, respectively. Paragraph (c) of § 192.619 provides an exception to this calculation of MAOP for pipelines built before the issuance of the Federal pipeline safety standards. A pipeline that is ''grandfathered'' under this section may be operated at a stress level exceeding 72 percent of SMYS (but not to exceed 80 percent of SMYS) if it was operated at that pressure for five years prior to July 1, 1970.

Part 192 also prescribes safety standards for designing, constructing, operating, and maintaining steel pipelines used to transport gas. Although these standards have always included several requirements for initial and periodic testing and inspection, prior to 2003, part 192 contained no Federal requirements for internal inspection of existing pipelines. Internal inspection is performed using a tool known as an ''instrumented pig'' (or ''smart pig''). Many pipelines constructed before the advent of this technology cannot accommodate an instrumented pig and, accordingly, cannot be inspected internally. Beginning in 1994, PHMSA required operators to design new pipelines so that they could accommodate instrumented pigs, paving the way for internal inspection (59 FR 17281; Apr. 12, 1994).

In December 2003, PHMSA adopted its gas transmission integrity management rule, requiring operators to develop and implement plans to extend additional protections, including internal inspection, to pipelines located in ''high consequence areas'' (68 FR 69816). Integrity management programs, as described in subpart O of part 192, include threat assessments, both baseline and periodic internal inspection or direct assessment, and additional measures designed to prevent and mitigate pipeline failures and their consequences. A high consequence area, as defined in § 192.903, is a geographic territory in which, by virtue of its population density and proximity to a pipeline, a pipeline failure would pose a higher risk to people. For purposes of risk analysis, the regulations establish four classifications based on population density, ranging from Class 1 (undeveloped, rural land) through Class 4 (densely populated urban areas). In addition to class location, one of the criteria for identifying a high consequence area is a potential impact circle surrounding a pipeline. The calculation of the circle includes a factor for the MAOP, with the result that a higher MAOP results in a larger impact circle.

B.2. Evolution in Views on Pressure

Absent any defects, and with proper maintenance, steel pipe can last for decades in gas service. However, the manufacture of the steel or casting of the pipe can introduce flaws. In addition, during construction, improper backfilling can damage pipe coating. Over time, damaged coating can allow corrosion to continue unchecked and cause leaks. During operation, excavators' substandard practices can dent the line or corrosion can thin the wall of the pipe.

The regulations on MAOP in part 192 have their origin in engineering standards developed in the 1950s, when industry had relatively limited information about the material properties of pipe and limited ability to evaluate a pipeline's integrity during its operating lifetime. Early pipeline codes allowed maximum operating pressures to be set at a fixed amount over the pressure of the initial strength test without regard to SMYS. Pipeline engineers developing consensus standards looked for ways to lengthen the time before defects initiated during manufacture, construction, or operation could grow to failure. Their solution focused on tests done at the mill to evaluate the ability of the pipe to contain pressure during operation. They added an additional factor to the hydrostatic test pressure of the mill test. At the time, the consensus standard, known as the B31.8 Code, used this conservative margin of safety for gas pipe design. A 25 percent margin of safety translated into a design factor limiting stress level to 72 percent of SMYS in rural areas. Specifically, the MAOP of 72 percent of SMYS comes from dividing the typical maximum mill test pressure of 90 percent of SMYS by 1.25. When issuing the first Federal pipeline safety regulations in 1970, regulators incorporated this design factor, as found in the 1968 edition of the B31.8 Code, into the requirements for determining the MAOP.

Even as the Federal regulations were being developed, some technical support existed for operation at a higher stress level, provided initial strength testing removed defects. In 1968, the American Gas Association published Report No. L30050 entitled *Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure* prepared by the Battelle Memorial Institute. The research study concluded that:

- It is inherently safer to base the MAOP on the test pressure, which demonstrates the actual in-place yield strength of the pipeline, than to base it on SMYS alone.
- High pressure hydrostatic testing is able to remove defects that may fail in service.
- Hydrostatic testing to actual yield, as determined with a pressure-volume plot, does not damage a pipeline.

The report specifically recommended setting the MAOP as a percentage of the field test pressure. In particular, it recommended setting the MAOP at 80 percent of the test pressure when the minimum test pressure is 90 percent of SMYS or higher. Although the committee responsible for the B31.8 Code received the report, the committee deferred consideration of its findings at that time because the Federal regulators had already begun the process to incorporate the 1968 edition of the B31.8 Code into the Federal pipeline safety standards.

More than a decade later, the committee responsible for development of the B31.8 Code, now under the auspices of the American Society of Mechanical Engineers (ASME), revisited the question of design factor it had deferred in the late 1960s. The committee determined pipelines could operate safely at stress levels up to 80 percent of SMYS. ASME updated the design factors in a 1990 addendum to the 1989 edition of the B31.8 Code, and they remain in the current edition. Although part 192 incorporates parts of the B31.8 Code by reference, it does not incorporate the updated design factors. With the benefit of operating experience with pipelines, it seems clear that operating pressure plays a less critical role in pipeline integrity and failure consequence than other factors within the operator's control.

By any measure, new technologies and risk controls have had a far greater impact on pipeline safety and integrity. A great deal of progress has occurred in the manufacture of steel pipe and in its initial inspection and testing. Technological advances in metallurgy and pipe manufacture decrease the risk of incipient flaws occurring and going undetected during manufacture. The detailed standards now followed in steel and pipe manufacture provide engineers considerable information about their material properties. The toughness standards make the new steel pipe more likely to resist fracture and to survive mechanical damage. Knowledge about the material properties allows engineers to predict how quickly flaws, whether inherent or introduced during construction or operation, will grow to failure under known operating conditions.

Initial inspection and hydrostatic testing of pipelines allow operators to discover flaws that have occurred prior to operation, such as during transportation or construction. They also serve to validate the integrity of the pipeline before operation. Initial pressure testing causes longitudinal and some other flaws introduced during manufacture, transportation, or construction to grow to the point of failure. Initial pressure testing detects all but one type of manufacturing or construction defect that could cause failure in the near term. The one type of defect pressure testing cannot identify is a flaw in a girth weld. Such defects are detectable though pre-operational non-destructive testing, which this proposed rule would require.

The most common defects initiated during operation are caused by mechanical damage or corrosion. Improvements in technology have resulted in internal inspection techniques that provide operators a significant amount of information about defects. Although there is significant variance in the capability of the tools used for internal inspections, they each provide the operator information about flaws in the pipeline that an operator would not otherwise have. An operator can then examine these flaws to determine whether they are defects requiring repair. In addition, internal inspections with inline inspection devices, unlike pressure testing, are not destructive and can be done while the pipeline is in operation. Initial internal inspection establishes a baseline. Operators can use subsequent internal inspections at appropriate intervals to monitor for changes in flaws already discovered or to find new flaws requiring repair or monitoring. Internal inspections, and other improved life cycle management practices, increase the likelihood operators will detect any flaws that remain in the pipe after initial inspection and testing, or that develop after construction, well before the flaws grow to failure.

B.3. History of PHMSA Consideration

Although the agency has never formally revisited its part 192 MAOP standards, developments in related arenas have increasingly set the stage for the more limited action we propose here. Grandfathered pipelines have operated successfully at higher stress levels in the United States during more than 35 years of Federal safety regulation. Many of these grandfathered pipelines have operated at higher stress levels for more than 50 years without a higher rate of failure. We have also been aware of pipelines outside the United States operating successfully at the higher stress levels permitted under the ASME standard. A technical study published in December 2000 by R.J. Eiber, M. McLamb, and W. B. McGehee, *Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level*, GRI–00/0233, further raised interest in the issue.

In connection with our issuance of the 2003 integrity management regulations, PHMSA announced a policy to grant ''class location'' waivers (now called special permits) to operators demonstrating an alternative integrity management program for the affected pipeline. A ''class location'' waiver allows an operator to maintain current operating pressure on a pipeline following an increase in population that changes the class location. Absent a waiver, the operator would have to reduce pressure or replace the pipe with thicker walled pipe. PHMSA held a meeting on April 14–15, 2004 to discuss the criteria for the waivers. In a notice seeking public involvement in the process (69 FR 22116; Apr. 23, 2004), PHMSA announced:

> Waivers will only be granted when pipe condition and active integrity management provides a level of safety greater than or equal to a pipe replacement or pressure reduction.

A second notice (69 FR 38948; June 29, 2004) announced the criteria. The criteria include the use of high quality manufacturing and construction processes, effective coating, and a lack of systemic problems identified in internal inspections. Although the class location waivers do not address increases in stress levels, they do address many of the same concerns by looking at how to handle the risks caused by operating pressure. Many of the specific criteria, and certainly the approach to risk management in the class location waivers, helped PHMSA develop the approach to the special permits discussed below and, ultimately, to this proposed rule.

Beginning in 2005, operators began addressing the issue of stress level directly with requests that PHMSA allow operation at the MAOP levels that the ASME B31.8 Code would allow. With the increasing interest, PHMSA held a public meeting on March 21, 2006, to discuss whether to allow increased MAOP consistent with the updated ASME standards. PHMSA also solicited technical papers on the issue. Papers filed in response, as well as the transcript of the public meeting, are in the docket for this rulemaking. Later in 2006, PHMSA again sought public comment at a meeting of its advisory committee, the Technical Pipeline Safety Standards Committee. The transcript and briefing materials for the June 28, 2006 meeting are in the docket for the advisory committee, Docket ID PHMSA-RSPA–1998–4470–204, 220. This docket can be found at *http://www.regulations.gov*. Comments and papers during these efforts overwhelmingly support examining increased MAOP as a way to increase energy efficiency and capacity without reducing safety.

B.4. Safety Conditions in Special Permits

In 2005, operators began requesting waivers, now called special permits, to allow operation at the MAOP levels that the ASME B31.8 Code would allow. In some cases, operators filed these requests at the same time they were seeking approval from the Federal Energy Regulatory Commission to build new gas transmission pipelines. In other cases, operators sought relief from current MAOP limits for existing pipelines that had been built to more rigorous design and construction standards.

In developing an approach to the requests, PHMSA examined the operating history of lines already operated at higher stress levels. Canadian and British standards have allowed operation at the higher stress levels for some time. The Canadian pipeline authority, which has allowed higher stress levels since 1973, reports the following experience with pipelines operating at stress levels higher than 72 percent of SMYS:

- About 6,000 miles of pipelines on the Alberta system, ranging from 6 to 42 inches in diameter, installed or upgraded between the early 1970s and 2005;
- About 4,500 miles of pipelines on the Mainline system east of the Alberta-Saskatchewan border, ranging from 20 to 42 inches in diameter, installed or upgraded between the early 1970s and 2005; and
- More than 600 miles in the Foothills Pipe Line system, ranging from 36 to 40 inches in diameter, installed between 1979 and 1998.

In the United Kingdom, about 1,140 miles of the Northern pipeline system has been uprated to operate at higher stress level in the past ten years.

In the United States, some 5,000 miles of gas transmission lines that were grandfathered under § 192.619(c) when the Federal pipeline safety regulations were adopted in the early 1970s continue to operate at stress levels higher than 72 percent of SMYS. After some accidents caused by corrosion on grandfathered pipelines, PHMSA considered whether to remove the exception in § 192.619(c). In 1992, PHMSA decided to continue to allow operation at the grandfathered pressures (57 FR 41119; Sept. 9, 1992). PHMSA based its decision on the operating history of two of the operators whose pipelines contained most of the mileage operated at the grandfathered pressures. PHMSA noted the incident rate on these pipelines, operated at stress levels above 72 percent of SMYS, was between 10 percent and 50 percent of the incident rate of pipelines operated at the lower pressure. Texas Eastern Gas Pipeline Company (now Spectra Energy), the operator of many of the grandfathered pipelines, attributed the lower incident rate to aggressive inspection and maintenance. This included initial hydrostatic testing to 100 percent of SMYS, internal inspection, visual examination of anomalies found during internal inspection, repair of defects, and selective pressure testing to validate the results of the internal inspection. Internal inspection was not in common use in the industry prior to the 1980s. PHMSA's statistics show these pipelines continue to have an equivalent safety record when compared with pipelines operating according to the design factors in the pipeline safety regulations.

PHMSA also considered technical studies and required companies seeking special permits to provide information about the pipeline's design and construction and to specify the additional inspection and testing to be used. PHMSA also considered how to handle findings that could compromise the long term serviceability of the pipe. PHMSA concluded that pipelines can operate safely and reliably at stress levels up to 80 percent of SMYS if the pipeline has well-established metallurgical properties and can be managed to protect it against known threats, such as corrosion and mechanical damage.

Early and vigilant corrosion protection reduces the possibility of corrosion occurring. At the earliest stage, this includes care in applying a protective coating before transporting the pipe to the right-of-way. With the newer coating materials and careful application, coating provides considerable protection against external corrosion and facilitates the application of induced current, commonly called cathodic protection, to prevent corrosion from developing at any breaks that may occur in the coating. Regularly monitoring the level of protection and addressing any low readings corrects conditions that can cause corrosion at an early stage. Vigilant corrosion protection includes close attention to operating conditions that lead to internal corrosion, such as poor gas quality. In addition, for new pipelines, operators' compliance with a rule issued earlier this year requiring greater attention to internal corrosion protection during design and construction (72 FR 20059; Apr. 23, 2007) will prevent internal corrosion. Finally, corrosion protection includes internal inspection and other assessment techniques for early detection of both internal and external corrosion.

One of the major causes of serious pipeline failure is mechanical damage caused by outside forces, such as an equipment strike during excavation activities. Burying the pipeline deeper, increased patrolling, and additional line marking helps prevent the risk that excavation will cause mechanical damage. Further, enhanced pipe properties increase the pipe's resistance to immediate puncture from a single equipment strike. Improved toughness increases the ability of the pipe to withstand mechanical damage from an outside force and also may also limit any failure consequences to leaks rather than ruptures. This toughness usually allows time for the operator to detect the damage during internal inspection well before the pipe fails.

To evaluate each request, PHMSA established a docket and sought public comment on the request. We received few public comments, most in response to the first special permits considered. Many of the comments supported granting the special permits. Those who did not may have been unappreciative of the significance of the safety upgrades required for the special permits. A few raised technical concerns. Among these were questions about the impact of rail crossings and blasting activities in the vicinity of the pipeline. The special permits did not change the current requirements where road crossings exist and added a requirement to monitor activities, such as blasting, that could impact earth movement. Some commenters expressed concern about the impact radius of the pipeline operating at a higher stress level. PHMSA included supplemental safety criteria to address the increased radius. The remainder of the comment addressed concerns, such as compensation or aesthetics, which were outside the scope of the special permits. PHMSA permits do not address issues on siting, which is governed by the Federal Energy Regulatory Commission.

PHMSA has now issued several special permits in response to these requests and continues to receive and evaluate other requests. The following table identifies the status of special permit requests and the dockets containing additional information about them.

TABLE B.4.—STATUS OF SPECIAL PERMITS

Docket ID PHMSA—	Status of request	Type
2005–23448, Maritimes & Northeast Pipeline (Spectra Energy)	Granted, July 11, 2006	Pipeline in operation since 1999.
2005–23387, Alliance Pipeline	Granted, July 11, 2006	Pipeline in operation since 2000.
2006–23998, Rockies Express Pipeline	Granted, July 11, 2006	New pipeline.
2006–25803, Kinder Morgan Louisiana Pipeline	Granted, April 19, 2007	New pipeline.
2006–25802, CenterPoint Energy Gas Transmission	Granted, July 18, 2007	New pipeline.
2006–26533, Gulf South Pipeline	Granted, August 24, 2007	New pipeline.
2006–26616, Ozark Gas Transmission	Pending	New pipeline.
2006–27607, Southeast Supply Header	Pending	New pipeline.
2006–27842, Midcontinent Express (Kinder Morgan)	Pending	New pipeline.
2007–27121, Transwestern Pipeline	Pending	Pipeline in operation since 1992 and 2005.
2007–28994, Gulf South Pipeline (SouthEast Expansion Project)	Pending	New pipeline.
2007–29078, Kern River Gas Transmission Company	Pending	Pipeline in operation since 1992.

In each case, PHMSA provides oversight to confirm the line pipe is, or will be, as free of inherent flaws as possible, that construction and operation do not introduce flaws, and that any flaws are detected before they can fail. PHMSA accomplishes this by imposing a series of conditions on the grant of special permits. The conditions are designed to address the potential additional risk involved in operating the pipeline at a higher stress level. A proposed pipeline must be built to rigorous design and construction standards, and the operator requesting a special permit for an existing pipeline must be able to demonstrate that the pipeline has been built to rigorous design and construction standards. These additional design and construction standards focus on producing a high quality pipeline that is free from inherent defects that could grow more rapidly under operation at a higher stress level and more resistant to expected operational risks. In addition, the operator of a pipeline receiving a special permit must comply with operation and maintenance requirements that exceed current pipeline safety regulations. These additional operation and maintenance requirements focus on the potential for corrosion and mechanical damage and on detecting defects before the defects can grow to failure.

B.5. Codifying the Special Permits

This proposed rule would put in place a process for managing the life cycle of a pipeline operating at a higher stress level. Integrity management focuses on managing and extending the service life of the pipeline. Life-cycle management goes beyond the operations and maintenance practices, including integrity management, to address steel production, pipeline manufacture, pipeline design, and installation.

Industry experience with integrity management demonstrates the value of life-cycle maintenance. Through baseline assessments in integrity management programs, gas transmission operators identified and repaired 2,883 defects in the first three years of the program (2004, 2005, and 2006). More than 2,000 of these were discovered in the first two years as operators assessed their highest risk, generally older, pipelines. In a September 2006 report, GAO–09–946, the General Accountability Office noted this data as an early indication of improvement in pipeline safety. In order to qualify for operation at higher stress levels under this proposed rule, pipelines will be designed and constructed under more rigorous conditions. Baseline assessment of these lines as proposed will likely uncover few defects, but removing those few defects will result in safer pipelines. In addition, the results of the baseline assessment will aid in evaluating anomalies discovered during future assessments.

This proposed rule, based on the terms and conditions of the special permits allowing operation at higher stress levels, would impose similar terms and conditions and limitations on operators seeking to apply the new rule. The terms and conditions, which include meeting current design standards that go beyond current regulation, address the safety concerns related to operating the pipeline at a higher stress level. PHMSA will step up inspection and oversight of pipeline design and construction, in addition to review and inspection of enhanced life-cycle maintenance requirements for these pipelines.

With special permits, PHMSA individually examined the design, construction, and operation and maintenance plans for a particular pipeline before allowing operation at a higher pressure than currently authorized. In each case, PHMSA conditioned approval based on compliance with a series of rigorous design, construction, operation, and maintenance standards. PHMSA's experience with these requests for special permits leads to the conclusion that a rule of general applicability is appropriate. With a rule of general applicability, the conditions for approval are established for all without need to craft the conditions based on individual evaluation. Thus, this proposed rule would set rigorous safety standards. In place of individual examination, the proposed rule would require senior executive certification of an operator's adherence to the more rigorous safety standards. An operator seeking to operate at a higher pressure than allowed by current regulation would have to certify that a pipeline is built according to rigorous design and construction standards and agree to operate under stringent operation and maintenance standards. After PHMSA receives an operator's certification indicating its intention to operate at a higher stress level, PHMSA could then follow up with the operator to verify compliance. As with the special permits, this proposed rule would allow an operator to qualify both new and existing segments of pipeline for operation at the higher MAOP, provided the operator meets the conditions for the segment.

Several types of segments will not qualify under the proposed rule. These include the following:

- Segments in densely populated Class 4 locations. In addition to the increased consequences of failure in a Class 4 location, the level of activity in such a location increases the risk of excavation damage.
- Segments of grandfathered pipeline already operating at a higher stress level but not constructed in accordance with modern standards. Although grandfathered pipeline has operated successfully at the higher stress level, PHMSA would examine any further increases individually through the special permit process.
- Bare pipe. This pipe lacks the coating needed to prevent corrosion and to make cathodic protection effective.
- Pipe with wrinkle bends. Section 192.315(a) currently prohibits wrinkle bends in pipeline operating at hoop stress exceeding 30 percent of SMYS.
- Pipe experiencing failures indicative of a systemic problem, such as seam flaws, during the initial hydrostatic testing. Such pipe is more likely to have inherent defects that can grow to failure more rapidly at higher stress levels and thus will not qualify.
- Pipe manufactured by certain processes, such as low frequency electric welding process, will not qualify because it could not satisfy the requirements of the proposed rule.
- Segments which cannot accommodate internal inspection devices. These segments would not qualify because the proposed rule would require internal inspection.

We are proposing to establish slightly different requirements for segments that have already been operating and those which are to be newly built. Some variation is necessary or appropriate with an existing pipeline. For example, the requirement for cathodically protecting pipeline within 12 months of construction is an existing requirement for all pipelines. A proposed requirement for the operator of an existing segment to prove that the segment was in fact cathodically protected within 12 months of construction provides greater confidence in the condition of the existing segment. Proposing proof of five percent fewer nondestructive tests done on an existing segment at the time of construction recognizes the possibility that, over time, an operator's records might not be complete. The overriding principal in the variation is to allow qualification of a quality pipeline with minimal distinction. Based on our review of requests for special permits on existing pipelines, PHMSA does not believe the more rigorous standards proposed here are too high for existing segments. Setting the qualification standards lower for existing segments could encourage operators to construct a pipeline at the lower standards and seek to raise the operating pressure at some future date.

Although pipeline proponents have not yet revealed their final plans, PHMSA anticipates the proposed trans-Alaskan gas pipeline will require an alternative design approach to address anticipated operating conditions in the Arctic. This alternative approach will be subject to PHMSA review. To a large degree, the technical requirements for operation at a higher stress level in this proposed rule will guide agency actions in reviewing the plans for a trans-Alaskan gas pipeline. However, the unique operating environment of the Arctic will dictate changes. For instance, even higher strength steels will be needed. PHMSA will have to look closely at the level of inspection needed to protect the environment and help ensure the long-term safety of the pipeline.

B.6. How To Handle Special Permits and Requests for Special Permits

Table B.4 describes the status of requests for special permits seeking relief from the current design requirements to allow operation at higher stress levels. For the most part, this proposed rule addresses the relief requested. PHMSA has already granted many of these under terms and conditions that vary slightly from those in this proposed rule. In some cases, the relief granted extends beyond the issues addressed in this proposed rule. It may be appropriate for PHMSA to review the special permits already granted after completion of the rulemaking to determine the need for changes. We seek comment on this issue.

PHMSA is also considering how to handle the pending requests and whether to consider others during the course of rulemaking. One option is to continue evaluating each request in light of the terms and conditions proposed here. Any grants of special permits during the course of rulemaking could be limited in time with the intention of revisiting the need for a special permit after completing the rulemaking. Another option is to defer further action on pending requests at least until PHMSA completes the rulemaking.

In any case, issuance of a final rule will not foreclose future requests for relief through the special permit process. We can anticipate, for instance, that operators may seek special permits covering pipeline that does not meet fully some of the terms and conditions in a final rule. In such a case, the operator may be able to demonstrate the existence of other safety measures that address the unmet terms and conditions. Notwithstanding the final rule, the operator would be able to request a special permit which PHMSA would consider under the usual public process for special permits.

B.7. Statutory Considerations

Under 49 U.S.C. 60102(a), PHMSA has broad authority to issue safety standards for the design, construction, operation, and maintenance of gas transmission pipelines. Under 49 U.S.C. 60104(b), PHMSA may not require an operator to modify or replace existing pipeline to meet a new design or construction standard. Although this proposal includes design and construction standards, these standards simply add more rigorous, non-mandatory requirements. This proposal does not require an operator to modify or replace existing pipeline or to design and construct new pipeline in accordance with these non-mandatory standards. If, however, a new or existing pipeline meets these more rigorous standards, the proposal would allow an operator to elect to calculate the MAOP for the pipeline based on a higher stress level. This would allow operation at an increased pressure over that otherwise allowed for pipeline built since the Federal regulations were issued in the 1970s. To operate at the higher pressure, the operator would have to comply with more rigorous operation and maintenance requirements.

Under 49 U.S.C. 60102(b), a gas pipeline safety standard must be practicable and designed to meet the need for gas pipeline safety and for protection of the environment. PHMSA must consider several factors in issuing a safety standard. These factors include the relevant available pipeline safety and environmental information, the appropriateness of the standard for the type of pipeline, the reasonableness of the standard, and reasonably identifiable or estimated costs and benefits. PHMSA has considered these factors in developing this proposed rule and provides its analysis in the preamble.

PHMSA must also consider any comments received from the public and any comments and recommendations of the Technical Pipeline Safety Standards Committee (Committee). Both the public and the Committee have already reviewed the concepts underlying this proposal. As discussed above, PHMSA opened this docket and conducted a public meeting in 2006 to discuss the potential for increasing MAOP. PHMSA subsequently briefed the Committee. Finally, PHMSA has sought public comment on several requests for special permits to allow operation at increased MAOP. PHMSA considered the Committee discussion and public comment in developing this proposed rule. This notice of proposed rulemaking seeks public comment on the proposed rule; the Committee will formally consider it in a future meeting. PHMSA will address the public comments and the Committee's recommendations in preparing final action.

C. The Proposed Rule

C.1. In General

The proposed rule would add a new section (§ 192.620) to Subpart L—Operations. This new section would explain what an operator would have to do to operate at a higher MAOP than currently allowed by the design requirements. Among the conditions set forth in proposed new § 192.620 is the requirement that the pipeline be designed and constructed to more rigorous standards. These additional design and construction standards are set forth in two additional new sections (§§ 192.112 and 192.328) to be located in Subpart C—Pipe Design and Subpart G—General Construction Requirements for Transmission Lines and Mains, respectively. In addition, the proposed rule would make necessary conforming changes to existing sections on incorporation by reference (§ 192.7) and maximum allowable operating pressure (§ 192.619).

C.2. Proposed Amendment to § 192.7—Incorporation by Reference

The proposed rule would add ASTM Designation: A 578/A578M—96 (Re-approved 2001) ''Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications'' to the documents incorporated by reference under § 192.7. This specification prescribes standards for ultrasonic testing of steel plates. It is referenced in proposed new § 192.112.

C.3. Proposed New § 192.112—Additional Design Requirements

The proposed rule would add a new section to Subpart C—Pipe Design in 49 CFR Part 192. The new section, § 192.112 would prescribe additional design standards required for the steel pipeline to be qualified for operation at an alternative MAOP based on higher stress levels. These include requirements for rigorous steel chemistry and manufacturing practices and standards. Pipelines designed under these standards contain pipe with toughness properties to resist damage from outside forces and to control fracture initiation and growth. The considerable attention paid to the quality of seams, coatings, and fittings would prevent flaws leading to pipe failure. Unlike other design standards, § 192.112 would apply to a new or existing pipeline only to the extent that an operator elects to operate at a higher

MAOP than allowed in current regulations.

Proposed paragraph (a) sets high manufacturing standards for the steel plate or coil used for the pipe. These include reducing oxygen content to produce more uniform chemistry in the plate and limiting the use of alloys in place of carbon. The pipe would be manufactured in accordance with level 2 of API Specification 5L, with the wall thickness and the ratio between diameter and wall thickness limited to prevent the occurrence of denting and ovality during construction or operation. Improved construction and inspection practices discussed elsewhere in this notice of proposed rulemaking also help prevent denting and ovality.

Proposed paragraph (b) addresses fracture control of the metal. First the metal would have to be tough; that is, deform plastically before fracturing. To the extent that the accepted industry toughness standard does not explicitly address the particular pipe used and expected operating conditions, correction factors would have to be used. Second, the pipe would have to pass several tests designed to reduce the risk that fractures would initiate. Third, to the extent it would be physically impossible for particular pipe to meet toughness standards under certain conditions, crack arrestors would have to be added to stop a fracture within a specified length.

Proposed paragraph (c) provides tests to verify that there are no deleterious imperfections in the plate or coil. The macro-etch test will identify flaws that impact the surface of the plate or coil. Interior flaws will show up in ultrasonic testing.

In addition to the quality of the steel, the integrity of a pipe depends on the integrity of the seams. Proposed paragraph (d) provides for a quality assurance program to assure tensile strength and toughness of the seams so that they resist breaking under regular operations. Hardness and ultrasonic tests would ensure that the seams also resist puncture damage.

Proposed paragraph (e) would require a longer mill test pressure for new pipe at a higher hoop stress than required by current regulations. The mill test is used to discover flaws introduced in manufacture. Because the pipeline will be operated at a higher stress level, the more rigorous mill test is needed to match (or exceed) the level of safety provided for pipelines operated at less than 72 percent of SMYS.

Proposed paragraph (f) would set rigorous standards for factory coating designed to protect the pipe from external corrosion. A quality assurance program would address all aspects of the application of coating that will protect the pipe. This would include applying a coating resistant to damage during installation of the pipe and examining the coated pipe to determine whether the applied coating is uniform and without gaps. Thin spots or holes in the coating make it more likely for corrosion to occur and more difficult to protect the pipe cathodically.

Proposed paragraph (g) would require that factory-made fittings, induction bends, and flanges be certified as to their serviceability. In addition, the amount of non-carbon added in the steel for these fittings and flanges would be limited.

Proposed paragraph (h) would require compressor design to limit the temperature of discharge to a specified maximum. Higher temperature can damage pipe coating. An exception to the specified maximum is allowed if testing of the coating shows it can withstand a higher temperature. The testing must be of sufficient length and rigor to detect coating integrity issues.

C.4. Proposed New § 192.328—Additional Construction Requirements

The proposed rule would also add a new section to Subpart G—General Construction Requirements for Transmission Lines and Mains. The new section, § 192.328, would prescribe additional construction requirements, including rigorous quality control and inspections, as conditions for operation of the steel pipeline at higher stress levels. These include requirements for rigorous quality control and inspection during construction. Unlike other construction standards, § 192.328 would apply to a new or existing pipeline only to the extent that an operator elects to operate at a higher MAOP than allowed in current regulations.

Proposed paragraph (a) would require a quality assurance plan for construction. Quality assurance, also called quality control, is common in modern pipeline construction. Activities such as lowering the pipe into the ditch and backfilling, if poorly done, can damage the pipe. Other construction activities such as nondestructive examination, if poorly done, will result in flaws remaining in the pipeline. Using a quality assurance plan helps to verify that the basic tasks done during construction of a pipeline are done correctly.

Field application of coating is one of these basic tasks to be covered in a quality assurance plan. During the course of analyzing requests for special permits, PHMSA discovered field coatings at one construction site which were applied at lower temperature than needed for good adhesion to the pipe. Because coating is so critical to corrosion protection, proposed paragraph (a) would require quality assurance plans to contain specific performance measures for field coating. Field coating would have to meet substantially the same standards as coating applied at the mill and the individuals applying the coating would have to be appropriately trained and qualified.

Proposed paragraph (b) would require non-destructive testing of all girth welds. Although past industry practice has been to non-destructively test only a sample of girth welds, no alternative exists for verifying the integrity of the remaining welds. The initial pressure testing once construction is complete does not detect flaws in girth welds. PHMSA believes that most modern pipeline construction projects include non-destructive testing of all girth welds. However, because the regulations do not require testing of all girth welds, an operator's records for pipelines already in operation may not be complete. To account for this, proposed paragraph (b) would require testing records for only 95 percent of girth welds on existing segments.

Proposed paragraph (c) would require deeper burial of segments operated at higher stress level. A greater depth of cover decreases the risk of damage to the pipeline from excavation, including farming operations.

Proposed paragraph (d) addresses the results of the initial strength test and the assurance these results provide that the material in the pipeline is free of pre-operational flaws which can grow to failure over time. Since the initial strength test is a destructive test, it only detects flaws relatively close to failure during operation. This could leave in place smaller flaws that could grow more rapidly at higher stress level. To prevent this from occurring, the proposed paragraph would disqualify any segment which experiences a failure during the initial strength test indicative of systemic flaws in the material.

Proposed paragraph (e) addresses cathodic protection on an existing segment. Applying this requirement to new segments is unnecessary since current regulations already require cathodic protection within 12 months of construction. Proposed paragraph (e) would prevent an existing segment not cathodically protected within 12 months after construction from qualifying for operation at a higher stress level under this proposed regulation.

Proposed paragraph (f) addresses electrical interference for new segments. During construction, it is relatively easy to identify sources of electrical interference which can impair future cathodic protection. Addressing interference at this time supports better corrosion control. The proposed additional operation and maintenance requirements of proposed § 192.620(d)(6) require operators electing operation at higher stress levels to address electrical interference on existing pipelines prior to raising the MAOP.

C. 5. Proposed Amendment to § 192.619—Maximum Allowable Operating Pressure

The proposed rule would amend existing § 192.619 by adding a new paragraph (d) Proposed § 192.619(d) would provide an additional means to determine the MAOP for certain steel pipelines. In addition, the proposed rule would make conforming changes to existing paragraph (a) of the section.

C.6. Proposed New § 192.620—Operation at an Alternative MAOP

The proposed rule would add a new section, § 192.620, to subpart L of part 192, to specify what an operator would have to do in order to elect an alternative MAOP based on higher stress levels. The proposed rule would apply to both new and existing pipelines.

C.6.1. Calculating the Alternative MAOP

Proposed § 192.620(a)

Proposed paragraph (a) describes how to calculate the alternative MAOP based on the higher stress levels. Qualifying segments of pipe would use higher design factors to calculate the alternative MAOP. For a segment currently in operation this would result in an increase in MAOP. No changes would be made in the design factors used for segments within compressor or meter stations or segments underlying certain crossings.

C.6.2. Which Pipeline Qualifies

Proposed § 192.620(b)

Proposed paragraph (b) describes which segments of new or existing pipeline are qualified for operation at the alternative MAOP. The alternative MAOP would be allowed only in Class 1, 2, and 3 locations. Only steel pipelines meeting the rigorous design and construction requirements of §§ 192.112 and 192.328 and monitored by supervisory data control and acquisition systems would qualify. Mechanical couplings in lieu of welding would not be allowed. Although the special permits did not expressly mention mechanical couplings, PHMSA would not have granted a special permit if the pipeline involved had mechanical couplings.

C.6.3. How an Operator Selects Operation Under This Section

Proposed §§ 192.620(c)(1) and (2)

Proposed paragraphs (c)(1) and (2) would require an operator to notify PHMSA when it elects to establish the MAOP under this section. An operator notifies PHMSA of the election by submitting a certification by a senior executive that the pipeline meets the rigorous additional design and construction regulations of this proposed rule. A senior executive must also certify that the operator has changed its operation and maintenance procedures to include the more rigorous additional operation and maintenance requirements of the proposed rule. In addition, a senior executive must certify that the operator has reviewed its damage prevention program in light of industry consensus standards and practices and made any needed changes to it to ensure that the program meets or exceeds those standards or practices. An operator would have to submit the certification at least 180 days prior to commencing operations at the MAOP established under this section. This will provide PHMSA sufficient time for appropriate inspection which may include checks of the manufacturing process, visits to the pipeline construction sites, analysis of operating history of existing pipelines, and review of test records, plans, and procedures.

C.6.4. Initial Strength Testing

Proposed § 192.620(c)(3)

Proposed paragraph (c)(3) addresses initial strength testing requirements. In order to establish the MAOP under this section, an operator would have to perform the initial strength testing of a new segment at a pressure at least as great as 125 percent of the MAOP. Since an existing pipeline was previously operated at a lower MAOP, it may have been initially tested at a pressure less than 125 percent of the higher MAOP allowed under this section. If so, paragraph (c) would allow the operator to elect to conduct a new strength test in order to raise the MAOP.

C.6.5. Operation and Maintenance

Proposed § 192.620(c)(4)

Proposed paragraph (c)(4) would require an operator to comply with the additional operating and maintenance requirements of paragraph (d). Compliance with these additional requirements is required if an operator elects to calculate the MAOP for a segment under paragraph (a) and notifies PHMSA of that election under paragraph (c)(1) of this section.

C.6.6. New Construction and Maintenance Tasks

Proposed § 192.620(c)(5)

Proposed paragraph (c)(5) addresses the need for competent performance of both new construction, and future maintenance activities, to ensure the integrity of the segment. PHMSA now requires operators to ensure that individuals who perform pipeline operation and maintenance activities are qualified. During a 2005 review of the qualifications program, PHMSA discussed the need to ensure that construction-related activities are properly done:

> We also have anecdotal information about errors in construction and the problems they cause. One incident [in late 2006] caused serious concern within PHMSA. The incident involved a dig-in by the pipeline company during construction near a large school. If the released gas had ignited, it could have resulted in a catastrophe exceeding the one that led to enactment of the Natural Gas Pipeline Safety Act of 1968. Although the construction project was not new construction, the distinctions between new construction and maintenance are often blurred, and excavation of the right-of-way of an active pipeline for any form of construction requires careful safety oversight. Federal and State inspectors can point to numerous situations in which they found dents or coating damage probably caused by poor backfill, pipeline handling, or equipment damage likely occurring during construction. When these problems become evident after the line has been in operation many years, it is too late for either remediation or enforcement action. Occasionally we have been able to address problems discovered soon after construction. As an example, a multi-agency investigation into construction of a natural gas transmission line in the mid-1990s uncovered numerous violations of pipeline safety and other environmental laws. Our enforcement order directed the operator to undertake a program to remediate the problems associated with numerous instances of improper backfill.
>
> Finally, we analyzed the pipeline incident data. In the first analysis, we reviewed the incidents from 1984 through 2005 where the operator had noted construction as either the primary or a secondary causal factor. Although the number of incidents is small, we observe a trend line increasing for both gas transmission and hazardous liquid pipelines. This is contrary to the general trend in pipeline incidents. We next looked at incidents in which we suspect construction issues were involved, incidents occurring within two years of construction of the pipeline. We eliminated those incidents clearly not caused by construction error, such

as excavation damage occurring during operation of the line. When we add these suspected construction-related incidents to those clearly involving construction error, the trend line, for both gas transmission and hazardous liquid pipelines, is sloped more steeply upward.

FDMS Docket ID PHMSA–RSPA–2004–19857–56, p. 2. Proposed paragraph (c)(5) would require operators seeking to operate at the higher stress levels allowed under this section to take steps designed to reduce incidents caused by errors during new construction and maintenance activities. As part of the 2005 review of the qualifications program, PHMSA sought comment on a broad approach to ensuring that construction-related activities are done properly. Proposed paragraph (c)(5) would incorporate this approach. The approach would allow an operator to select an appropriate way to verify the proper performance of a construction-related activity. For example, non-destructive testing of all girth welds will significantly reduce the risk of a future weld failure. An operator could also effectively use quality controls during construction or qualify the individuals performing the tasks. Both industry consensus standards, and subpart N, provide models for qualifying individuals performing safety tasks.

C.6.7. Recordkeeping

Proposed § 192.620(c)(6)

Proposed paragraph (c)(6) clarifies recordkeeping requirements for operators electing to establish the MAOP under this section. Existing regulations, such as §§ 192.13, 192.517(a), and 192.709, already require operators to maintain records applicable to this section. However, because the additional requirements proposed in this section address requirements found in other subparts of part 192, the recordkeeping requirements may cause confusion. For example, proposed § 192.620(d)(9) would require a baseline assessment for integrity for a segment operated at the higher stress level regardless of its potential impact on a high consequence area. Section 192.947 requires operators to maintain records of baseline assessments for the useful life of the pipeline. However, proposed new § 192.620 would be in subpart L. Section 192.709 requires an operator to retain records for an inspection done under subpart L for a more limited time. Accordingly, this paragraph would clarify the need to maintain all records demonstrating compliance for the useful life of the pipeline.

C.7. Additional Operation and Maintenance Requirements

Proposed § 192.620(d)

Paragraph (d) sets forth 11 operating and maintenance requirements that supplement the existing requirements in part 192. Current § 192.605 requires an operator to develop operation and maintenance procedures to implement the requirements of subpart L and M. Since proposed § 192.620(d) is in subpart L, an operator would have to develop and follow the operation and maintenance procedures developed under this section. These include requirements for an operator to evaluate and address the issues associated with operating at higher pressures. Through its public education program, an operator would inform the public of any risks attributable to higher pressure operations. The additional operating and maintenance requirements address the two main risks the pipelines face, excavation damage and corrosion, through a combination of traditional practices and integrity management. Traditional practices include cathodic protection, control of gas quality, and maintenance of burial depth. Integrity management includes internal inspection on a periodic basis to identify and repair flaws before they can fail. These are discussed in more detail below.

C.7.1. Threat Assessments

Proposed § 192.620(d)(1)

Proposed paragraph (d)(1) would require preparation of a threat assessment consistent with that done under integrity management to address the risks of operating at an increased stress level. This proposed requirement is not limited to high consequence areas, but applies to the entire segment operating at the increased stress level.

This proposed requirement comes from our experience with integrity management and special permits. Under integrity management, operators develop a detailed threat matrix identifying the risks associated with operating their pipelines. These risks include both general risks faced by all pipelines and those risks specific to the particular pipeline and its environment. The matrix lists specific threats and the mitigative measures an operator is using to address each threat. As applied to the special permits, and in this proposed rule, this threat assessment ensures that an operator takes into account any additional risk operation at a higher stress level imposes.

C.7.2. Public Awareness

Proposed § 192.620(d)(2)

Proposed paragraph (d)(2) would require an operator to include any people potentially impacted by operation at a higher stress level within the outreach effort in its public education program required under existing § 192.616. In order to identify this population, an operator would use a broad area measured from the centerline of the pipe plus, in high consequence areas, the potential impact circle recalculated to reflect operation at a higher stress level. This is intended to get necessary information for safety to the people potentially impacted by a failure.

C.7.3. Emergency Response

Proposed § 192.620(d)(3)

Proposed paragraph (d)(3) addresses the additional needs for responding to emergencies for operation at higher stress levels. Consistent with the conditions imposed in the special permits, and past experience with response issues, the paragraph would require methods such as remote control valves to provide more rapid shut-down in the event of an emergency.

C.7.4. Damage Prevention

Proposed § 192.620(d)(4)

Proposed paragraph (d)(4) addresses one of the major risks of failure faced by a pipeline, damage from outside force such as damage occurring during excavation in the right-of-way. Although the improved toughness of pipe reduces the risk of damage, it does not prevent it and additional measures are appropriate for pipelines operating at higher stress levels. This paragraph proposes to add several new or more specific measures to existing requirements designed to prevent damage to pipelines from outside force. Additional attention to this area is important since the trend line for incidents caused by outside force on gas transmission pipelines between 2002 and 2006 is increasing.

The first more specific measure, in proposed paragraph (d)(4)(i), addresses patrolling, required for all transmission pipelines by § 192.705. More frequent patrols of the right-of-way prevent damage by giving the operator more accurate and timely information about potential sources of ground disturbance and other outside force damage. These include both naturally occurring conditions, such as wash outs, and human activity, such as construction in the vicinity of the pipeline. The proposed requirement would be for patrols on the same frequency as for hazardous liquid pipelines (i.e., a minimum of 26 times a year). This is slightly more frequent than included in the special permits, but PHMSA believes that it is appropriate for a rule of general applicability.

The increased patrols that would be required by this rulemaking, however, represent the majority of the incremental costs imposed by this rule. Therefore, PHMSA specifically requests comment on whether the number of patrols required optimally balances the potential risk reduction and increase in burden. We seek information on:

- Would patrolling less frequently such as four times per year (similar to requirements at highway and railroad crossings) provide a cost-effective alternative?
- How often are pipelines that currently operate at 80% of SMYS patrolled? How effective are these patrols in providing accurate and timely information about potential sources of ground disturbance and other outside force damage?
- How could operators incorporate patrolling in their risk management plan if PHMSA did not mandate a fixed frequency?

Other more specific or new measures to address damage prevention include developing and implementing a plan to monitor and address ground movement, a proposed requirement of paragraph (d)(4)(ii). Ground movement such as earthquakes, landslides, and nearby demolition or tunneling can damage pipe. Since pipelines near the surface are more likely to be damaged by surface activities, proposed paragraph (d)(4)(iii) would require an operator to maintain the depth of cover over a pipeline. Line-of-sight markers alert excavators, emergency responders, and the general public of the presence and general location of pipelines. Proposed paragraph (d)(4)(iv) would require these markers to improve both damage prevention and enhance public awareness.

Damage prevention programs are improving because of the work being done by the Common Ground Alliance, a national, non-profit educational organization dedicated to preventing damage to pipelines and other underground utilities. The Common Ground Alliance has compiled best practices applicable to all parties relevant to preventing damage to underground utilities and actively promotes their use. Proposed paragraph (d)(4)(v) would require operators electing to operate at higher stress levels to evaluate their damage prevention programs in light of industry consensus standards and practices. An operator would have to identify the standards or practices used and make appropriate changes to the damage prevention program. The resulting program would have to meet or exceed the identified standards or practices. This approach is consistent with annual reviews of operation and maintenance programs under § 192.605. An operator would have to include in the certification required under proposed § 192.620(c)(1) that the review and upgrade has occurred.

Proposed paragraph (d)(4) would also require one measure not included as a condition in the special permits, namely a right-of-way management plan. In the past several years, PHMSA has seen recurring similarities in pipeline accidents on construction sites. In each case, better management of the pipeline right-of-way could have prevented the accidents. Better management would include closer attention to the qualifications of individuals critical to damage prevention, better marking practices, and closer oversight of the excavation. In 2006, PHMSA issued two advisory bulletins to alert operators of the need to pay closer attention to these important damage prevention issues. The first advisory bulletin described three accidents in which either operator personnel or contractors damaged gas transmission pipelines during excavation in the rights-of-way (ADB–06–01; 71 FR 2613; Jan. 17, 2006). This bulletin advised operators to pay closer attention to integrating operator qualification regulations into excavation activities and providing that excavation is included as a covered task under operator qualification programs required by subpart N. The second advisory bulletin pointed to an additional excavation accident where the excavator struck an inadequately marked gas transmission pipeline (ADB–06–03; 71 FR 67703; Nov. 22, 2006). This advisory bulletin advised pipeline operators to pay closer attention to locating and marking pipelines before excavation activities begin and pointed to several good practices as well as the best practices described by the Common Ground Alliance. This proposed paragraph would require an operator electing to operate at a higher stress level to develop a plan to manage the protection of their right-of-way from excavation activities. Each operator already has a damage prevention program, under § 192.614, and a program to ensure qualification of pipeline personnel, under subpart N. This management plan would require the operator to integrate activities under those programs to provide better protection for the right-of-way of pipeline operated at higher stress level.

C.7.5. Internal Corrosion Control

Proposed § 192.620(d)(5)

Proposed paragraph (d)(5) would add specificity to the requirements for internal corrosion control now in pipeline safety standards for pipelines operated at higher stress levels. These internal corrosion control programs would have to include mandated use of filter separators, gas quality monitoring equipment, cleaning pigs, and inhibitors. Maximum levels of contaminants that could promote corrosion are set to be monitored quarterly. PHMSA believes the levels are fully consistent with the requirements in Federal Energy Regulatory Commission tariffs designed to prevent internal corrosion.

C.7.6. External Corrosion Control

Proposed §§ 192.620(d)(6), (7), and (8)

Since external corrosion is one of the greatest risks to the integrity of pipelines operating at higher stress levels, the special permits and this proposed rule contain several measures to prevent it from occurring. These include use of effective coating, addressing interference, early installation of cathodic protection, confirming the adequacy of coating and cathodic protection and diligent monitoring of cathodic protection levels. The quality of the coating and installation of cathodic protection are addressed in proposed sections on design and construction. The remaining external corrosion provisions are addressed here.

Interference from overhead power lines, railroad signaling, stray currents, or other sources can interfere with the cathodic protection system and, if not properly mitigated, even accelerate the rate of external corrosion. Proposed paragraph (d)(6) would require an operator to identify and address interference early before damage to the pipe can occur.

Proposed paragraph (d)(7) would require an operator to confirm both the effectiveness of the coating and the adequacy of the cathodic protection system soon after deciding on operation at higher stress levels. This is accomplished through indirect assessment, such as a close interval survey. After completion of the baseline internal inspection required by proposed § 192.620(d)(9), an operator would have to integrate the results of that inspection with the indirect assessments. An operator would have to also take remedial action to correct any inadequacies. In high consequence areas, an operator would have to periodically repeat indirect assessment to confirm that the cathodic protection system remains as functional as when first installed.

Proposed paragraph (d)(8) would require more rigorous attention to ensure adequate levels of cathodic protection. Regulations now require an operator discovering a low reading, meaning a reduced level of protection, must act promptly to correct the deficiency. This section puts an outer limit of six months on the time for completion of the remedial action and restoration of an adequate level of cathodic protection. In addition, the operator would have to confirm, through a close interval survey, that adequate cathodic protection levels were restored.

C.7.7 Integrity Assessments

Proposed §§ 192.620(d)(9) and (10)

Among the most important ways of ensuring integrity during pipeline operations are the assessments done under the integrity management program requirements in subpart O. Proposed paragraphs (d)(9) and (d)(10) would require operators electing to operate at higher stress levels to perform both baseline and periodic assessments of the entire segment operating at the higher stress level, regardless of whether the segment is located in a high consequence area. The operator would have to use both a geometry tool and a high resolution magnetic flux tool for the entire segment. In very limited circumstances in which internal inspection is not possible because internal inspection tools cannot be accommodated, such as a short crossover segment connecting two pipelines in a right-of-way, an operator would substitute direct assessment. The operator would then integrate the information provided by these assessments with testing done under previously described paragraphs. This analysis would form the basis for mitigating measures described in the operator's threat assessment, and prompt repairs under proposed paragraph (d)(11).

C.7.8. Repair Criteria

Proposed § 192.620(d)(11)

The repair criteria under proposed paragraph (d)(11) for anomalies in a segment operating at a higher stress level are slightly more conservative than for other pipeline, including pipeline covered by a integrity management program. With the tougher pipe, better coating and seams, and careful attention to damage prevention and corrosion protection, a pipeline operated at higher stress levels should experience few anomalies needing evaluation. The higher stress levels of operation can allow more rapid growth of anomalies. Therefore, more conservative repair criteria are needed.

C.8. Overpressure Protection

Proposed § 192.620(e)

The alternative MAOP is higher than the upper limit of the required overpressure protection under existing regulations. Proposed paragraph (e) would increase the overpressure protection limit to 104 percent of the MAOP, which is 83 percent of SMYS, for a segment operating at the alternative MAOP.

D. Regulatory Analyses and Notices

D.1. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477).

D.2. Executive Order 12866 and DOT Policies and Procedures

Due to billions of dollars in benefits, the Department of Transportation (DOT) considers this proposed rulemaking to be a significant regulatory action under section 3(f)(1) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, DOT submitted it to the Office of Management and Budget for review. This proposed rulemaking is also significant under DOT regulatory policies and procedures (44 FR 11034; Feb. 26, 1979).

PHMSA prepared a draft Regulatory Evaluation of the proposed rule. A copy is in Docket ID PHMSA–2005–23447. If you have comments about the Regulatory Evaluation, please file them as described under the **ADDRESSES** heading of this document.

PHMSA estimates that the proposed rule will result in gas transmission pipeline operators uprating 3,500 miles of existing pipelines to an alternative MAOP. Additionally PHMSA estimates that, in the future, the proposed rule will result in an annual additional 700 miles of new pipeline whose operators elect to use an alternative MAOP.

PHMSA expects the benefits of the proposed rule to be substantial and greatly in excess of $100 million per year. This expectation is based on quantified benefits in excess of $100 million per year (see below), coupled with un-quantified benefits associated with the proposed rule that industry and PHMSA technical staff have identified. The expected benefits of the proposed rule that cannot be readily quantified include:

- Reductions in incident consequences
- Increases in pipeline capacity
- Increases in the amount of natural gas filling the line, commonly called line pack
- Reductions in capital expenditures on compressors for new pipelines
- Reductions in adverse environmental impacts

In the case of new pipelines, the ability to use an alternative MAOP will make it possible to transport more product. Quantifying the value of this increased capacity is difficult, and no estimate has been developed for this analysis. Nonetheless, PHMSA expects the value of increased capacity due to use of alternative MAOP by gas pipelines to be significant. Estimates made with respect to the proposed trans-Alaskan gas pipeline include an estimated increase of 14.2 million standard cubic feet of gas per day. In areas where production is already well-established, there is an even greater potential for increased pipeline capacity. For example, one recipient of a special permit estimated a daily increase of at least 62 million standard cubic feet of gas.

Similarly, increases in line pack will produce enormous benefits which are difficult to quantify. The reduced amount of exterior storage capacity resulting from increased line pack may result in capital or operation and maintenance savings for the pipelines or their customers. Increased line pack increases the ability to continue gas delivery during short outages such as maintenance and to increase the amount of gas quickly during peak periods. These benefits are not readily quantifiable.

The quantified benefits consist of

- Fuel cost savings
- Capital expenditure savings on pipe for new pipelines

Of these, pipeline fuel cost savings is the most important contributor to the estimated benefits. Although these quantified benefits do not capture the full benefits of the proposed rule, they exceed $100 million per year.

As a consequence of the proposed rule, PHMSA estimates that pipeline operators will realize annually recurring benefits due to fuel cost savings of $58.8 million that begin in the initial year after the rule goes into effect and $9.8 million that begin in each subsequent year. Additionally, PHMSA estimates that each year pipeline operators will realize one-time benefits for savings in capital expenditures of $54.6 million (since 700 miles of new pipeline operating at an alternative MAOP are added each year, the one-time benefits resulting from this added mileage will be the same each year.) The benefits of the proposed rule over 20 years are expected to be as presented in the following table:

TABLE D.2.–1—SUMMARY AND TOTAL FOR THE ESTIMATED BENEFITS OF THE PROPOSED RULE

Benefit	Estimate for year 1 (millions of dollars per year)	Estimate of new benefits occurring in each subsequent year (millions of dollars per year)
Reduced incident consequences	Not quantified	Not quantified.
Fuel cost savings	$49.0 (recurring)	$0.0 (recurring).
Reduced capital expenditures	$54.6 (non-recurring)	$54.6 (non-recurring).
Increased pipeline capacity	Not quantified	Not quantified.
Increased line pack	Not quantified	Not quantified.
Reduced adverse environmental impacts	Not quantified	Not quantified.
Other expected benefits	Not quantified	Not quantified.
Total	$49.0 recurring + $54.6 non-recurring.	$54.6 non-recurring.

The present value of the benefits evaluated over 20 years at a three percent discount rate would be $1,541 million, while the present value of the benefits over 20 years at a seven percent discount rate would be $1,098 million. For both discount rates, the annualized benefits would be $103.6 million.

PHMSA expects the costs attributable to the proposed rule are most likely to be incurred by operators for

- Performing baseline internal inspections
- Performing additional internal inspections
- Performing anomaly repairs
- Installing remotely controlled valves on either side of high consequence areas
- Preparing threat assessments
- Patrolling pipeline rights-of-way
- Preparing the paperwork notifying PHMSA of the decision to use an alternative MAOP

Overall, the costs of the proposed rule over 20 years are expected to be as presented in the following table:

TABLE D.2.–2—SUMMARY AND TOTALS FOR THE ESTIMATED COSTS OF THE PROPOSED RULE

Cost item	Cost by year after implementation (thousands of dollars)			
	1st	2nd–10th	11th	12th–20th
Baseline internal inspections	$29,119	None	None	None.
Additional internal inspections	None	None	$17,471	$2,912 each year.
Anomaly repairs	$1,015	None	$1,218	$203 each year.
Remotely controlled valves	$3,528	$588 each year	$588	$588 each year.
Threat assessments	$180	$30 each year	$30	$30 each year.
Patrolling	$10,080	$11,760 to $25,200	$26,880	$28,560 to $42,000.
Notifying PHMSA	Nominal	Nominal	Nominal	Nominal.
Total	$43,922	$618 each year plus patrolling costs.	$46,187	$3,733 each year plus patrolling costs.

The present value of the costs evaluated over 20 years at a three percent discount rate would be $435 million, while the present value of the costs over 20 years at a seven percent discount rate would be $293 million. The annualized costs at the 3% discount rate would be $29 million, while the annualized costs at the 7% discount rate would be $28 million.

Since the present value of the quantified benefits ($1,541 million at three percent and $1,098 million at seven percent) exceeds the present value of the costs ($435 million at three percent and $293 million at seven percent), the proposed rule is expected to be cost-beneficial.

D.3. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities.

The proposed rule would affect operators of gas pipelines. Based on annual reports submitted by operators, there are approximately 1,450 gas transmission and gathering systems and an equivalent number of distribution systems potentially affected by the proposed rule. The size distribution of these operators is unknown and must be estimated.

The affected gas transmission systems all belong to NAICS 486210, Pipeline Transportation of Natural Gas. In accordance with the size standards published by the Small Business Administration, a business with $6.5 million or less in annual revenue is considered a small business in this NAICS.

Based on August 2006 information from Dunn & Bradstreet on firms in NAICS 486210, PHMSA estimates that 33% of the gas transmission and gathering systems have $6.5 million or less in revenue. Thus, PHMSA estimates that 479 of the gas transmission and gathering systems affected by the proposed rule will have $6.5 million or less in annual revenue. PHMSA does not expect that any local gas distribution companies or gathering systems will be taking advantage of the potential to use an alternative MAOP.

The proposed rule mandates no action by gas transmission pipeline operators. Rather, it provides those operators with the option of using an alternative MAOP in certain circumstances, when certain conditions can be met. Consequently, it imposes no economic burden on the affected gas pipeline operators, large or small. Based on these facts, I certify that this proposed rule will not have a substantial economic impact on a substantial number of small entities.

PHMSA invites public comment on impacts this proposed rule would have on small entities.

D.4. Executive Order 13175

PHMSA has analyzed this proposed rulemaking according to Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because the proposed rulemaking would 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.

D.5. Paperwork Reduction Act

This proposed rule adds notification and threat assessment paperwork requirements on pipeline operators voluntarily choosing an alternative MAOP for their pipelines. Based on analysis of the regulation, there will be an estimated 2,712 total annual burden hours attributable to the notification and threat assessment requirements in the first year. In following years, the annual burden is expected to decrease to 452 hours. The associated cost of these annual burden hours is $180,289 in year one, and $30,048 thereafter. No other burden hours and associated costs are expected. See the Paperwork Reduction Act analysis in the docket for a more detailed explanation. PHMSA seeks comments on these projections.

D.6. Unfunded Mandates Reform Act of 1995

This proposed 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 in any one year 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 proposed rulemaking.

D.7. National Environmental Policy Act

PHMSA has analyzed the proposed rulemaking for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). The proposed rulemaking would require limited physical change or other work that would disturb pipeline rights-of-way. In addition, the proposed rulemaking would codify the terms of special permits PHMSA has granted. Although PHMSA sought public comment on environmental impacts with respect to most requests for special permits to allow operation at pressures based on higher stress levels, no commenters addressed environmental impacts. PHMSA has preliminarily determined the proposed rulemaking is unlikely to significantly affect the quality of the human environment. An environmental assessment document is available for review in the docket. PHMSA will make a final determination on environmental impact after reviewing the comments to this proposal.

D.8. Executive Order 13132

PHMSA has analyzed the proposed rulemaking according to Executive Order 13132 (64 FR 43255, Aug. 10, 1999) and concluded that no additional consultation with States, local governments or their representatives is mandated beyond the rulemaking process. The proposed rule does not have a substantial direct effect 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. The proposed rule does not impose substantial direct compliance costs on State or local governments.

Further, no consultation is needed to discuss the preemptive effect of the proposed rule. The pipeline safety law, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. The same law provides that Federal regulation would not preempt state law for intrastate pipelines. In addition, 49 U.S.C. 60120(c) provides that the Federal pipeline safety law ''does not affect the tort liability of any person.'' It is these statutory provisions, not the proposed rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

D.9. Executive Order 13211

This proposed rulemaking is likely to increase the efficiency of gas transmission pipelines. A gas transmission pipeline operating at an increased MAOP will result in increased capacity, fuel savings, and flexibility in addressing supply demands. This is a positive rather than an adverse effect on the supply, distribution, and use of energy. Thus this proposed rulemaking is not a ''significant energy action'' under Executive Order 13211. Further, the Administrator of the Office of Information and Regulatory Affairs has not identified this proposed rule as a significant energy action.

List of Subjects in 49 CFR Part 192

Design pressure, Incorporation by reference, Maximum allowable operating pressure, and Pipeline safety.

For the reasons provided in the preamble, PHMSA proposes to amend 49 CFR part 192 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. In § 192.7, in paragraph (c)(2) amend the table of referenced material by redesignating items C.(6) through C.(13) as C.(7) through C.(14) and adding a new item C.(6) to read as follows:

§ 192.7 Incorporation by reference.

* * * * *

(c) * * *

(2) * * *

Source and name of referenced material	49 CFR reference
* * * * * * *	
C.* * *	
(6) ASTM Designation: A 578/A578M—96 (Re-approved 2001) ''Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications.	§ 192.112(c)(2)(ii)
* * * * * * *	

3. Add § 192.112 to subpart C to read as follows:

§ 192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under § 192.620, a segment must meet the following additional design requirements:

To address this design issue:	The pipeline segment must meet this additional requirement:
(a) General standards for the steel pipe	(1) The plate or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. (2) The carbon equivalents of the steel used for pipe must not exceed 0.23 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula), for wall thickness of one inch (25 mm) or less, and 0.25 percent for wall thickness greater than one inch (25 mm). (3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses. (4) The pipe must be manufactured using API Specification 5L, product specification level 2 (incorporated by reference, see § 192.7) for maximum operating pressures and minimum operating temperatures and other requirements under this section.
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with: (i) API Specification 5L (incorporated by reference, see § 192.7); and (ii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Specification 5L, product specification level 2 (incorporated by reference, see § 192.7). (2) Fracture control must: (i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures and gas compositions the pipeline is expected to experience; (ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters; (iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and (iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see § 192.7) and ensures ductile fracture and arrest with the following exceptions: (A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and (B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. (3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, mechanical crack arrestors of proper design and spacing must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.
(c) Plate/coil quality control	(1) There must be a comprehensive mill inspection program to check for defects and inclusions affecting pipe quality. (2) This mill inspection program must include: (i) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of at least 2 on the Mannesmann scale or equivalent; and (ii) An ultrasonic test of the ends and at least 50 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For pipeline designed after [the effective date of the final rule], the test must be done in accordance with Level B of ASTM A 578/A578M (incorporated by reference, see § 192.7) or equivalent.
(d) Seam quality control	(1) There must be a quality assurance program for pipe seam welds: (i) To assure tensile strength provided in API Specification 5L (incorporated by reference, see § 192.7) for appropriate grades; and (ii) To assure toughness of at least 35 foot-pounds at 32 degrees Fahrenheit (or minimum operating temperature). (2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method to assure a maximum hardness of 280 Vickers of the following: (i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and (ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal). (3) All of the seams must be ultrasonically tested after cold expansion and hydrostatic testing.
(e) Mill hydrostatic test	(1) All pipe to be used in a new segment must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 20 seconds, including the allowance for end loading stresses. (2) Pipe previously in operation must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.

To address this design issue:	The pipeline segment must meet this additional requirement:
(f) Coating	(1) The pipe must be protected against external corrosion by non-shielding, fusion bonded epoxy coating. (2) Coating on pipe used for trenchless installation must resist abrasions and other damage possible during installation. (3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.
(g) Fittings and flanges	(1) There must be certification records of flanges, factory induction bends and factory weld ells. (2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure.
(h) Compressor stations	(1) A compressor station must be designed to limit discharge temperature to a maximum of 120 degrees Fahrenheit (49 degrees Centigrade) or the higher temperature allowed in paragraph (h)(2) of this section. (2) If testing shows that the coating will withstand a higher temperature in long-term operations, the compressor station may be designed to limit discharge temperature to that higher temperature.

4. Add § 192.328 to subpart G to read as follows:

§ 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under § 192.620, a segment must meet the following additional construction requirements:

To address this construction issue:	*The pipeline segment must meet this additional construction requirement:*
(a) Quality assurance	(1) The construction of the segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. (2) The quality assurance plan for applying and testing field applied coating to girth welds must be: (i) Equivalent to that required under § 192.112(f)(3) for pipe; and (ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating.
(b) Girth welds	(1) All girth welds on a new segment must be non-destructively examined in accordance with § 192.243(b) and (c). (2) At least 95 percent of girth welds on a segment that was constructed prior to the effective date of this rule must have been non-destructively examined in accordance with § 192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in § 192.327, there must be at least 36 inches (914 millimeters) of cover. (2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The segment must not experience any failures indicative of fault in material during strength testing, including initial hydrostatic testing.
(e) Cathodic protection	(1) If the segment has been in operation, the cathodic protection system on the segment must have been operational within 12 months of construction.
(f) Interference currents	(1) For a new segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

5. Amend § 192.619 by revising paragraph (a) introductory text and by adding paragraph (d) to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

* * * * *

(d) The operator of a segment of steel pipeline meeting the conditions prescribed in § 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under § 192.620(a).

6. Add § 192.620 to subpart L to read as follows:

§ 192.620 Alternative maximum allowable operating pressure for certain steel pipelines.

(a) *How does an operator calculate the alternative maximum allowable operating pressure?* An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under § 192.619(a) as follows:

(1) In determining the design pressure under § 192.105, use a design factor determined in accordance with § 192.111 (b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

Class location	Design factor (F)
1	0.80
2	0.67
3	0.56

(2) The maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the segment was tested after construction by a factor determined in the following table:

Class location	Factor
1	1.25
2	1.50
3	1.50

(b) *When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section?* An operator may use a maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The segment is in a Class 1, 2, or 3 location;

(2) The segment is constructed of steel pipe meeting the additional design requirements in § 192.112;

(3) A supervisory control and data acquisition system provides remote monitoring and control of the segment;

(4) The segment meets the additional construction requirements described in § 192.328;

(5) The segment does not contain any mechanical couplings used in place of girth welds; and

(6) If a segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a fault in material.

(c) *What is an operator electing to use the alternative maximum allowable operating pressure required to do?* If an operator elects to use the maximum allowable operating pressure calculated under paragraph (a) of this section for a segment, the operator must do each of the following:

(1) Certify, by signature of a senior executive officer of the company, as follows:

(A) The segment meets the conditions described in subsection (b) of this section; and

(B) The operating and maintenance procedures include the additional operating and maintenance requirements of subsection (d) of this section; and

(C) The review and any needed program upgrade of the damage prevention program required by subsection (d)(4)(v) of this section has been completed.

(2) Notify PHMSA of its election with respect to a segment at least 180 days before operating at the alternative maximum allowable operating pressure by sending the certification to the Information Resources Manager as provided for reports under § 192.951.

(3) For each segment, do one of the following:

(i) Perform a strength test as described in § 192.505 at a test pressure of at least 125 percent of the maximum allowable operating pressure calculated under paragraph (a) of this section; or

(ii) For a segment in existence prior to the effective date of this regulation, certify, under paragraph (c)(1) of this section, that the strength test performed under § 192.505 was conducted at a test pressure of at least 125 percent of the maximum allowable operating pressure calculated under paragraph (a) of this section.

(4) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.

(5) If the performance of a construction task affects the integrity of the segment, ensure that the task is performed properly by doing at least one of the following:

(i) Include quality controls during construction addressing performance of the task;

(ii) Use an integrity verification method that addresses performance of the task; or

(iii) Demonstrate that the individual performing the task has the knowledge, skills, and ability to do so.

(6) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(5), and (d) of this section.

(d) *What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?* In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	*Take the following additional step:*
(1) Assessing threats	Develop a threat matrix consistent with § 192.917 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and (ii) Describe procedures used to mitigate the risk.
(2) Notifying the public	(i) Recalculate the potential impact circle as defined in § 192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and (ii) In implementing the public education program required under § 192.616, do the following: (A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and (B) Include information about the integrity management activities performed under this section within the message provided to the audience.
(3) Responding to an emergency in an area defined as a high consequence area in § 192.903.	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section. (ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour, provide remote valve control through a supervisory control and data acquisition system, other leak detection system, or an alternative method of control. (iii) Remote valve control must include the ability to open and close the valve, monitor the position of the valve, and monitor pressure upstream and downstream. (iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	*Take the following additional step:*
(4) Protecting the right of way	(i) Patrol the right of way at intervals not exceeding 3 weeks, but at least 26 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline. (ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement. (iii) Maintain the depth of cover provided for new pipeline under § 192.327 or § 192.328(c). If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover. (iv) Use line-of-sight line markers satisfying the requirements of § 192.707(d) except in agricultural areas, large water crossings or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law. (v) Review the damage prevention program under § 192.614(a) in light of national consensus standards and practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program. (vi) Develop and implement a right-of-way management plan to protect the segment from damage due to excavation activities.
(5) Controlling internal corrosion	(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents. (ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators and gas quality monitoring equipment. (iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling. (iii) Use cleaning pigs and inhibitors, and sample accumulated liquids. (iv) Address deleterious gas stream constituents as follows: (A) Limit carbon dioxide to 3 percent by volume; (B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and (C) Limit hydrogen sulfide to 0.50 grain per hundred cubic feet of gas. (v) Review the program at least quarterly based on the gas stream experienced and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion.	(i) Prior to operating an existing segment at a maximum allowable operating pressure calculated under this section, or within six months after placing a new segment in service at a maximum allowable operating pressure calculated under this section, address interference issues on the segment. (ii) To address interference issues, do the following: (A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion; (B) Analyze the results of the survey; and (C) Take any remedial action needed to protect the segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment.	(i) Within six months after placing the cathodic protection of a new segment in operation, or within six months after recalculating the maximum allowable operating pressure of an existing segment under this section, assess the integrity of the coating and adequacy of the cathodic protection through an indirect method such as close-interval survey, direct current voltage gradient, or alternating current voltage gradient. (ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe indication under section 4, table 3 of NACE RP–0502–2002 (incorporated by reference, see § 192.7). (iii) Within six months after completing the baseline internal inspection required under paragraph (9) of this section, integrate the results of the indirect assessment required under paragraph (7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions. (iv) For all segments in high consequence areas, do periodic assessments as follows: (A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part. (B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area. (C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.
(8) Controlling external corrosion through cathodic protection.	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading; and (ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station.
(9) Conducting a baseline assessment of integrity.	(i) Except as provided in paragraph (d)(9)(iii) of this section, for a new segment, do a baseline internal inspection as follows: (A) Assess using a geometry tool after the initial hydrostatic test and backfill within six months after placing the new segment in service; and (B) Assess using a high resolution magnetic flux tool within three years after placing the new segment in service.

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	*Take the following additional step:*
	(ii) Except as provided in paragraph (d)(9)(iii) of this section, for an existing segment, do a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure as allowed under this section. (iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a segment cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment to assess that portion.
(10) Conducting periodic assessments of integrity.	(i) Determine a frequency for subsequent periodic inspections as if the segments were covered by subpart O of this part. (ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (d)(10)(i) of this section. (iii) Use direct assessment for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (d)(9)(iii) of this section.
(11) Making repairs	(i) Do the following when evaluating an anomaly: (A) Use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and (B) Take into account the tolerances of the tools used for the inspection. (ii) Repair a defect immediately if any of the following apply: (A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in § 192.309(b). (B) The defect meets the criteria for immediate repair in § 192.933(d). (C) The maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the maximum allowable operating pressure. (D) The maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the maximum allowable operating pressure. (iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply: (A) The defect meets the criteria for repair within one year in § 192.933(d). (B) The maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the maximum allowable operating pressure. (C) The maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the maximum allowable operating pressure. (D) The maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the maximum allowable operating pressure. (iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?* Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by § 192.201, if an operator establishes a maximum allowable operating pressure for a segment in accordance with paragraph (a) of this section, an operator must:

(1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

(2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

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Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Parts 223 and 224

[Docket No. 080229343–8368–01]

RIN 0648–XF87

Listing Endangered and Threatened Species: Notification of Finding on a Petition to List Pacific Eulachon as an Endangered or Threatened Species under the Endangered Species Act

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

ACTION: Notification of finding; request for information, and initiation of status review.