Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified by Executive Order 13175 (59 FR 22951, November 9, 2000). This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999), because it merely makes a determination based on air quality data and results in the suspension of certain Federal requirements, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. This rule also is not subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it determines that air quality in the affected area is meeting Federal standards.

The requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply because it would be inconsistent with applicable law for EPA, when determining the attainment status of an area, to use voluntary consensus standards in place of promulgated air quality standards and monitoring procedures that otherwise satisfy the provisions of the Clean Air Act.

This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*)

Under Executive Order 12898, EPA finds that this rule involves a determination of attainment based on air quality data and will not have disproportionately high and adverse human health or environmental effects on any communities in the area, including minority and low-income communities.

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by May 19, 2008. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: November 13, 2009.

Laura Yoshii,

Acting Regional Administrator,

Region IX.

■ Part 52 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart F—California

■ 2. Section 52.282 is amended by adding paragraph (c) to read as follows:

§ 52.282 Control strategy and regulations: Ozone.

* * * * *

(c) *Determination of attainment.* Effective January 4, 2010, EPA is determining that the Imperial County, California 8-hour ozone nonattainment area has attained the 1997 8-hour ozone standard. Under the provisions of EPA's ozone implementation rule (see 40 CFR 51.918), this determination suspends the reasonable further progress and attainment demonstration requirements of section 182(b)(1) and related requirements of section 172(c)(9) of the Clean Air Act for as long as the area does not monitor any violations of the 8-hour ozone standard. If a violation of the 1997 ozone NAAQS is monitored in the Imperial County, California 8-hour ozone nonattainment area, this determination shall no longer apply.

[FR Doc. E9–28536 Filed 12–2–09; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket ID PHMSA–2007–27954; Amdt. Nos. 192–112 and 195–93]

RIN 2137–AE28

Pipeline Safety: Control Room Management/Human Factors

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

ACTION: Final rule.

SUMMARY: PHMSA is amending the Federal pipeline safety regulations to address human factors and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition (SCADA) systems. Under the final rule, affected pipeline operators must define the roles and responsibilities of controllers and provide controllers with the necessary information, training, and processes to fulfill these responsibilities. Operators must also implement methods to prevent controller fatigue. The final rule further requires operators to manage SCADA alarms, assure control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event.

Hazardous liquid and gas pipelines are often monitored in a control room by controllers using computer-based equipment, such as a SCADA system, that records and displays operational information about the pipeline system, such as pressures, flow rates, and valve positions. Some SCADA systems are used by controllers to operate pipeline equipment, while, in other cases, controllers may dispatch other personnel to operate equipment in the field. These monitoring and control actions, whether via SCADA system commands or direction to field personnel, are a principal means of managing pipeline operation.

This rule improves opportunities to reduce risk through more effective control of pipelines. It further requires

the statutorily mandated human factors management. These regulations will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management.

DATES: *Effective Date:* The effective date of this final rule is February 1, 2010. *Compliance Date:* An operator must develop control room management procedures by August 1, 2011 and implement the procedures by February 1, 2012.

Incorporation by Reference Date: The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of February 1, 2010.

FOR FURTHER INFORMATION CONTACT: For technical information contact: Byron Coy at (609) 989–2180 or by e-mail at *Byron.Coy@dot.gov.* For legal information contact: Benjamin Fred at (202) 366–4400 or by e-mail at *Benjamin.Fred@dot.gov.* All materials in the docket may be accessed electronically at *http://www.regulations.gov.* General information about PHMSA may be found at *http://phmsa.dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. Pipelines

Approximately two-thirds of our domestic energy supplies are transported by pipeline. There are roughly 170,000 miles of hazardous liquid pipelines, 295,000 miles of gas transmission pipelines, and 1.9 million miles of gas distribution pipelines in the United States. Hazardous liquid pipelines carry crude oil to refineries and refined products to locations where these products are consumed or stored for later use. Hazardous liquid pipelines also transport highly volatile liquids (HVLs), other hazardous liquids such as anhydrous ammonia, and carbon dioxide. The regulations in 49 CFR part 195 apply to owners and operators of pipelines used in the transportation of hazardous liquids and carbon dioxide. Throughout this document, the term ''hazardous liquid'' refers to all products in pipelines regulated under part 195. In addition, the term ''operator'' refers to both owners and operators of pipeline facilities.

Gas transmission pipelines typically carry natural gas over long distances from gas gathering, supply, or import facilities to localities where it is used to heat homes, generate electricity, and fuel industry. Gas distribution pipelines take natural gas from transmission pipelines and distribute it to residential, commercial, and industrial customers. The regulations in 49 CFR part 192 apply to operators of pipelines that transport natural gas, flammable gas, or gas which is toxic and corrosive. Throughout this document, the term ''gas'' refers to all gases in pipelines regulated under part 192.

B. Control Rooms and Controllers

Pipelines vary from small and simple to large and complex. Pipelines often span broad geographic areas. Gas distribution pipelines may cover entire metropolitan areas, literally street-by-street. Gas transmission and hazardous liquid pipelines may traverse hundreds or thousands of miles. Equipment exists throughout pipelines that must be operated to control the safe movement of commodity. This includes pumps and compressors to provide motive force and valves that control pressure or change position to direct the flow of commodity. In many cases, parameters measuring pipeline operations, such as pressure and flow, are monitored from remote, central locations referred to as control rooms. Pipeline equipment may also be operated remotely from control rooms. The employees who monitor pipeline parameters and direct certain actions from control rooms are known as controllers.

Most pipelines are underground and operate without disturbing the environment or negatively impacting public safety. However, accidents do occur occasionally. Effective control is one key component of accident prevention.[1] Controllers can help identify risks, prevent accidents, and minimize commodity loss if provided with the necessary tools and working environment. This rule will increase the likelihood that pipeline controllers have the necessary knowledge, skills, and abilities to help prevent accidents. The rule will also ensure that operators provide controllers with the necessary training, tools, procedures, management support, and environment where a controller's actions can be effective in helping to assure safe operation.

Most operators use computer-based SCADA systems, distributed control systems (DCS), or other less sophisticated systems to gather key information electronically from field locations.[2] These systems are configured to present field data to the controllers, and may include additional historical, trending, reporting, and alarm management information. Controllers track routine operations continuously and watch for developing abnormal operating or emergency conditions. A controller may take direct action through the SCADA system to operate equipment or the controller may alert and defer action to others.

Control rooms and controllers are critical to the safe operation of pipelines. Control rooms often serve as the hub or command center for decisions such as adjusting commodity flow or facilitating an operator's initial response to an emergency. The control room is the central location where humans or computers receive data from field sensors. Commands from the control room may be transmitted back to remotely controlled equipment. Field personnel also receive significant information from the control room. In essence, the control room is the ''brain'' of many pipeline systems.

Errors made in control rooms can have significant effects on the controlled systems. A controller's errors can initiate or exacerbate an accident. A controller's improper action or lack of action can place undue stresses on a pipeline, which could result in a subsequent failure, the loss of service, or an increase in lost commodity and risk to people, property, the environment, and the fuel supply. On the other hand, proper controller responses to developing abnormal operating conditions or accidents can alleviate the consequences of some events, or prevent them altogether, regardless of the initial cause.

C. Knowledge and Information Are Required To Do the Job

A controller must possess certain abilities, and attain the knowledge and skills necessary to complete the various tasks required for a specific pipeline system. To attain the necessary knowledge and skills, the controller is typically required to complete extensive on-the-job training and is often closely observed by an experienced controller for a period of time. The controller must also review and understand appropriate procedures, including those associated with emergency response, and repeatedly practice the correct responses to a variety of abnormal operating conditions. Pipeline operators periodically evaluate a controller's skills and knowledge through the regulatory-

[1] The pipeline safety regulations in 49 CFR parts 191, 192, and 193 refer to certain events on a gas pipeline system as ''incidents'' while part 195 refers to similar failures on a hazardous liquid pipeline system as ''accidents.'' Throughout this document the terms ''accident'' and ''incident'' may be used interchangeably to mean an event or failure on a gas or hazardous liquid pipeline.

[2] SCADA, DCS or other similar systems perform similar functions. Throughout this document, where the term SCADA is used, it should be interpreted to mean SCADA, DCS or other similar systems.

required operator qualification (OQ) process.

Pipeline controllers must have adequate and up-to-date information about the conditions and operating status of the equipment they monitor and control if they are to succeed in maintaining pipeline safety. Incorrect, delayed, missing, or poorly displayed data may confuse a controller and lead to problems despite the extensive training, qualification, and abilities of the controller. SCADA systems perform the function of gathering this information and displaying it to the controller. Operators need to assure that SCADA systems perform this important function correctly, and that the information is displayed in a manner that facilitates controller understanding and recognition of abnormal operating conditions.

D. Control Room Management

All of this must occur within an environment that facilitates appropriate and correct actions. Operators must prudently manage the factors affecting the controller. This includes relevant human factors, such as factors that can affect controller fatigue, and operator processes and procedures for managing the pipeline from the control room. PHMSA refers to the combination of all these factors as control room management. This rule requires that operators take specific actions to assure that pipeline control room management contributes to the safe operation of pipeline facilities.

E. NPRM

On September 12, 2008, PHMSA published a notice of proposed rulemaking (NPRM) (73 FR 53076) proposing to require operators of hazardous liquid pipelines, gas pipelines, and liquefied natural gas (LNG) facilities to amend their existing written operations and maintenance procedures, OQ programs, and emergency plans to assure controllers and control room management practices and procedures are adequate to maintain pipeline safety and integrity. In summary, the NPRM proposed to revise the Federal pipeline safety regulations by:

(1) Requiring operators to amend their Operations and Maintenance Manuals to address the human factors management plan required by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act (Pub. L. 109–468), Section 12).

(2) Defining the terms alarm, controller, control room, and SCADA.

(3) Requiring operators to define roles and responsibilities so that management and controllers have uniform expectations and understandings about response requirements before an abnormal operating condition or emergency arises.

(4) Requiring operators to establish procedures to facilitate controllers receiving management input in a timely manner when required.

(5) Requiring operators to assure that controllers receive the timely and necessary information they need to fulfill their responsibilities.

(6) Requiring operators to conduct an initial point-to-point baseline verification for each SCADA system to validate and document that field equipment configurations agree with computer displays.

(7) Requiring operators to record critical information during each shift.

(8) Requiring operators to include in their written procedures a limit on the length of time a controller may work and a requirement to allow time for adequate rest between shifts.

(9) Requiring two levels of alarm management review.

(10) Requiring operators to establish thorough and frequent communication between controllers, management, and field personnel when planning and implementing changes to pipeline equipment and configuration.

(11) Requiring operators to review all reportable accidents and incidents and certain other events on a routine basis to identify and correct deficiencies related to: Controller fatigue; field equipment; procedures; SCADA system configuration and performance; and training.

(12) Requiring operators to include certain content in their controller training programs. The proposed rule included a minimum set of elements that would overlap and supplement existing OQ programs.

(13) Requiring additional controller qualifications to measure or verify a controller's performance, including the prompt detection of, and appropriate response to, abnormal and emergency conditions likely to occur.

(14) Mandating that a senior executive officer validate certain aspects of controller training, qualification, and compliance with the requirements of this rule.

(15) Requiring operators to maintain records that demonstrate compliance with the regulation and to document any deviations from their control room management procedures.

The intent of the NPRM was to ensure that pipeline controllers would have the necessary knowledge, skills, abilities, and qualifications to help prevent accidents. The proposal was also intended to assure that operators would provide controllers with accurate information and the training, tools, procedures, management support, and operating environment where a controller's actions can help prevent accidents and minimize commodity losses. The requirements proposed in the NPRM were based on a controller study conducted by PHMSA that had identified areas for enhancement, an NTSB SCADA safety study, and certain mandates in the PIPES Act.

F. PHMSA Controller Study

As detailed in the NPRM, PHMSA had been studying and evaluating control room operations for many years and began developing control room inspection guidance in 1999. Congress subsequently enacted the Pipeline Safety Improvement Act of 2002 (PSIA) (Pub. L. 107–355), which required a pilot program be conducted to evaluate the need for pipeline controllers to be certified through tests and other requirements. In response to the PSIA, PHMSA conducted the Controller Certification (CCERT) project study and reported its findings to Congress within a report dated December 17, 2006, entitled ''Qualification of Pipeline Personnel.'' This project included a comprehensive review of existing controller training, qualification processes, procedures, and practices. This review also included identifying potential enhancements to controller qualifications and control room operations, such as validation and certification processes currently used in other industries to enhance public safety. Additional information on the CCERT study may be found in the NPRM.

G. NTSB SCADA Study

The NTSB conducted a safety study on hazardous liquid pipeline SCADA systems during the same period PHMSA conducted its CCERT study. While the PHMSA project addressed a wider perspective of interest, the two studies include similar findings.[3] The NTSB study identified areas for potential improvement, which resulted in five recommendations. Three are incorporated in this final rule. PHMSA is addressing the other two recommendations independent of this rulemaking.

The impetus of the NTSB study was a number of hazardous liquid accidents investigated by the NTSB in which there was a delay between the initial

[3] *See* ''Supervisory Control and Data Acquisition (SCADA) Systems in Liquid Pipelines,'' Safety Study NTSB/SS–05–02, adopted November 29, 2005.

indications of a leak evident on the SCADA system and the controller's initiation of response efforts. The NTSB designed its SCADA study to examine how hazardous liquid pipeline companies use SCADA systems to monitor and record operating data and to evaluate the role of SCADA systems in leak detection. The study identified five areas for potential improvement:

- Display graphics.
- Alarm management.
- Controller training.
- Controller fatigue data collection.
- Leak detection systems.

While the NTSB SCADA study specifically addressed hazardous liquid pipelines, the report included an appendix of all NTSB SCADA-related recommendations since 1976, which resulted from investigations of both hazardous liquid and gas pipeline accidents. Since 1976, the NTSB has issued approximately 30 recommendations to various entities related to SCADA systems involving both hazardous liquid and gas pipeline systems. PHMSA considers the NTSB recommendations in the most-recent SCADA safety study to be applicable for both gas and hazardous liquid pipelines. The recommendations being addressed through this rulemaking are as follows:

NTSB Recommendation P–05–1

Operators of hazardous liquid pipelines should be required to follow the API Recommended Practice 1165 (API RP 1165) for the use of graphics on the SCADA screens.

NTSB Recommendation P–05–2

PHMSA should require pipeline companies to have a policy for the review and audit of SCADA-based alarms.

NTSB Recommendation P–05–3

Operators should be required to include simulator or non-computerized simulations for training controllers in recognition of abnormal operating conditions, in particular leak events.

H. PIPES Act of 2006

The PIPES Act introduced additional requirements for PHMSA with respect to control room management and human factors. Section 12 of the PIPES Act (codified at 49 U.S.C. 60137) requires PHMSA to issue regulations requiring each operator of a gas or hazardous liquid pipeline to develop, implement, and submit a human factors management plan designed to reduce risks associated with human factors, including fatigue, in each control room for the pipeline. The plan must include, among other things, a maximum limit on the hours of service for controllers working in a control room. PHMSA, or a state authorized to exercise safety oversight, is required to review and approve operators' human factors plans, and operators are required to notify PHMSA (or the appropriate state) of any deviations from the plan. Section 19 of the PIPES Act requires PHMSA to issue standards to implement the three recommendations of the NTSB SCADA safety study described above. This final rule fulfills requirements in sections 12 and 19 of the PIPES Act.

II. Summary of Public Comments

PHMSA received a total of 144 comments on the NPRM, including comments from trade associations, municipal operators, local distribution companies (LDC), NTSB, LNG facilities, gas transmission pipeline operators, other gas distribution pipeline operators, hazardous liquid pipeline operators, state regulators, and private citizens. In addition, PHMSA participated in two trade association meetings during the public comment period: (1) On October 14–15, 2008, at the American Petroleum Institute (API) and Association of Oil Pipelines (AOPL) forum for control room management in Houston, Texas; and (2) on October 30, 2008, at the American Gas Association (AGA) control room management workshop in Ashburn, Virginia. Summaries of PHMSA's interactions at these meetings are available in the docket. Subsequent to the public comment period, on February 12, 2009, PHMSA staff met with NTSB staff in Washington, DC to discuss NTSB's comments on fatigue mitigation. A summary of this meeting is also in the docket.

The national pipeline trade associations, consisting of the AGA, the American Public Gas Association (APGA), the API, the AOPL, and the Interstate Natural Gas Association of America (INGAA), submitted a joint comment on October 8, 2008, shortly after the NPRM was issued, suggesting the agency withdraw the proposed rule. The associations contended that the proposed rule was overly-broad, unduly burdensome, and exceeded what the associations saw as the intent of Congress. They proposed that PHMSA issue an amended proposed rule with a clear scope and revised definitions that would reflect congressional intent and input from previous public meetings, and that would incorporate available consensus standards to a greater degree.

The trade associations submitted a second letter on November 12, 2008, reaffirming their previous suggestion that the proposed rule be reissued. The second joint letter provided alternative rule language to support the associations' suggested re-issuance of the proposed rule. The letter also suggested that PHMSA provide its pipeline safety advisory committees the opportunity to vote on their suggested alternative language at a joint committee meeting scheduled for December 2008.

AGA, APGA, INGAA, and API/AOPL also individually submitted comments on the proposed rule. Other associations that submitted comments were: The National Association of Pipeline Safety Representatives (NAPSR), Northeast Gas Association (NGA), Texas Energy Coalition (TEC), Texas Oil and Gas Association (TXOGA), and Texas Pipeline Association (TPA). NGA supported AGA's comments and TEC, TXOGA, and TPA supported the joint trade associations' comments and the associated alternative regulatory language. APGA stated that the rule as written would have a disproportionately greater impact on small utilities with no offsetting benefits based on its survey that found, on average, 22 percent of small public gas system employees would be classified as controllers subject to this rule. APGA noted that the agency's Regulatory Impact Analysis (RIA) did not address adequately the impact on small entities.

NAPSR is an organization of state agency pipeline safety managers responsible for the administration of their state's pipeline safety programs. NAPSR expressed concerns about jurisdictional authority in situations where a pipeline crosses State boundaries while under the control of a control room, or where a pipeline connects to a dispatch center or communications center in another State. NAPSR proposed adopting the definitions of control room and controller in API Recommended Practice 1168 (API RP 1168) to resolve the issue of jurisdictional authority.

Comments from individual pipeline operators generally echoed the comments of the joint trade associations and the individual trade associations. Their comments mainly addressed the scope of the proposed rule. Many of these commenters were concerned with the proposed definitions of ''controller'' and ''control room,'' contending that these definitions would have the effect of making the proposed rule's scope unreasonably broad. Another area of significant concern was the proposed requirement to conduct a 100 percent baseline data point verification of SCADA systems. Pipeline operators generally commented that this proposed requirement would entail significant cost for very limited benefit. The pipeline operators all supported the alternative regulatory language submitted by the joint trade associations or their own trade association.

III. Advisory Committees Meeting

On December 11, 2008, the Technical Pipeline Safety Standards Committee (TPSSC) and the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) met jointly for their bi-annual public meeting in Arlington, Virginia.[4] This meeting included consideration of the proposed control room management rule. As described above, the joint trade associations had submitted comments suggesting that the proposal be withdrawn and that the rule be significantly revised before being reissued. The associations submitted proposed alternative rule language as a basis for revision and had asked that the advisory committees be afforded the opportunity to consider their revised language if PHMSA did not withdraw the proposed rule.

Based on the comments filed by the joint trade associations, those received during the public meetings described above, and the general trend of other comments, PHMSA presented the Advisory Committees with three variations of the regulatory language being considered by the Agency. These included the language proposed in the NPRM, the alternative language proposed by the joint trade associations, and a third option that reflected the trade associations' proposed language with modifications to reflect critical NPRM language and other comments that had been received. PHMSA provided these variations of the regulatory language to facilitate the Advisory Committee members' discussion of the rule and to provide a process by which the members could recommend a certain course of action by PHMSA with regard to the rule. Although PHMSA had not selected any particular course of action at that time, PHMSA expressed its view that the third option might be the most viable alternative.

The TPSSC discussed exempting gas distribution from all requirements of this rulemaking action. After substantial discussion, the TPSSC voted against recommending that PHMSA exclude distribution from the rule, but voted in favor of recommending that PHMSA limit the requirements placed on certain small distribution operators to fatigue management and associated recordkeeping issues.

The Advisory Committees provided additional substantive and editorial comments to the proposed definitions, the scope of part 192, general requirements, requirements concerning SCADA systems, verification, backup control, fatigue mitigation, alarm management, change management, operating experience, and training requirements. Also, members of the public were afforded an opportunity to comment during the meeting, and several participants from the public provided their viewpoints for the record. After further discussion among the members, the TPSSC voted twelve to one, and the THLPSSC voted unanimously in favor. Also, both Advisory Committees provided a recommendation for PHMSA to make the changes noted during discussion. A transcript of the Advisory Committees meeting is posted in the docket (PHMSA–2007–27954–0184.2).

The Advisory Committees recommended the following changes to the rule language proposed in the NPRM:

- Changing the definitions of controller and control room to limit the scope of the rule. The revised definitions would exclude field personnel who operate equipment and operator personnel who use SCADA information but who have no operational responsibility to respond to SCADA indications.
- Adding a scope statement to explicitly limit the application of the rule to controllers using SCADA systems.
- Excluding gas distribution pipelines serving less than 250,000 customers or gas transmission pipelines without compressor stations from many of the requirements.
- Reducing specificity in the elements operators would be required to define as controllers' roles and responsibilities.
- Limiting applicability of SCADA display guidance in API RP 1165 to SCADA systems that would be installed or undergo certain changes after the rule became effective.
- Requiring point-to-point verification of SCADA only when new field equipment is installed or when changes are made to field equipment or displays that could affect pipeline safety.
- Eliminating requirements to implement additional measures to monitor for fatigue when only a single controller is on duty.
- Reducing the scope and frequency of required alarm reviews.
- Eliminating the proposed requirement that operators review for lessons learned pipeline events that did not require reporting as incidents and focusing required reviews of incidents on those events where there is reason to believe that control room actions contributed to the event.
- Deferring to existing requirements for operator qualification rather than imposing an additional qualification requirement for controllers.
- Eliminating the proposed requirement that a senior officer of each pipeline company submit certification that the requirements of the rule have been implemented.

Our changes to the final rule in response to the comments and advisory committees' recommendations are discussed below in section V.

IV. Summary of Final Rule

This final rule imposes requirements for control room management for all gas and hazardous liquid pipelines subject to parts 192 and 195 respectively that use SCADA systems and have at least one controller and control room. The scope of the rule is narrower in several respects than was proposed in the NPRM. First, for the reasons set forth below, LNG facilities are not covered by the rule, and no new requirements are adopted for part 193. In addition, changes to the proposed definition of a controller focus the new requirements on persons who work in control rooms and use SCADA systems to control their pipelines. The scope of the final rule has also been revised for gas pipeline operators such that each control room whose operations are limited to either or both of distribution with fewer than 250,000 customers or gas transmission without compressor stations must follow procedures with appropriate documentation that implement only the requirements for fatigue management, validation, and compliance and deviations. Pipelines meeting these criteria are generally smaller and simpler. They pose less complexity, obviating the need for the other requirements in this rule.

This rule requires pipeline operators to have and follow written control room management procedures. The operators must define the roles and responsibilities of controllers in normal, abnormal, and emergency operating

[4] The TPSSC and THLPSSC are statutorily-mandated advisory committees that advise PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines and for hazardous liquid pipelines. Both committees were established under the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 1) and the pipeline safety law (49 U.S.C. Chap. 601). Each committee consists of 15 members—with membership evenly divided among the Federal and State government, the regulated industry, and the public. The committees advise PHMSA on technical feasibility, practicability, and cost-effectiveness of each proposed pipeline safety standard.

situations. The final rule does not enumerate specific responsibilities that must be defined, as did the proposed rule. Instead, the final rule leaves the scope of controller responsibilities to be defined by each pipeline operator taking into consideration the characteristics of its pipeline and its methods of safely managing pipeline operation.

Pipeline operators will be required by this final rule to assure that new SCADA displays and displays for SCADA systems that are expanded or replaced meet the provisions of the consensus standard governing such displays, API RP 1165. Displays for gas pipelines are required to meet only some provisions of the standard. The proposed rule would not have limited applicability of this requirement to new or modified SCADA systems. Operators will be required to validate the accuracy of SCADA displays whenever field equipment is added or moved and when other changes that may affect pipeline safety are made to field equipment or SCADA displays. The proposed rule would have required that all operators perform a 100 percent verification of existing SCADA systems within a few years. This provision was not included in the final rule. Pipeline operators will also be required to test any backup SCADA systems and to test and verify a means to manually operate the pipeline (in the event of a SCADA failure) at least annually.

Pipeline operators must also establish a means of recording shift changes and other situations in which responsibility for pipeline operations is handed over from one controller to another. Such changes in responsibility may occur at scheduled shift changes or within a shift, when a controller is relieved for breaks and other reasons. Handovers can also occur between control rooms, for example where only one of multiple control rooms is used during night shifts. Pipeline operators will need to define procedures for shift changes and other circumstances in which responsibility for pipeline operation is transferred from one controller to another. The procedures must include the content of information to be exchanged during the turnover.

Pipeline operators must implement measures to prevent fatigue that could influence a controller's ability to perform as needed. Operators will need to schedule their shifts in a manner that allows each controller enough off-duty time to achieve eight hours of continuous sleep. Operators must train controllers and their supervisors to recognize the effects of fatigue and in fatigue mitigation strategies. Finally, each operator's procedures must establish a maximum limit on the number of hours that a controller can work. PHMSA recognizes there may be infrequent emergencies during which an operator may find the need to deviate from the maximum limit it has established to ensure adequate coverage in the control room for emergency response. Accordingly, the regulation provides that an operator's procedures may provide for the deviation from the maximum limit in the case of an emergency. Such a deviation would only be permitted if necessary for the safe operation of the pipeline facility. PHMSA or the head of the appropriate State agency, as the case may be, may review the reasonableness of any deviation from an operator's maximum limit on hours of service when considering whether to take enforcement action.

All pipeline operators are subject to the fatigue management requirement, even those whose operations do not involve multiple shifts. Controller fatigue can affect even single-shift pipeline operations and the PIPES Act requires that all pipeline operators have a plan that addresses fatigue. PHMSA expects that small operators, many of which operate only a single shift, will be able to meet these requirements with little effort. Shift schedule rotation is not an issue for these operators and written instructional material (e.g., pamphlets) that can be reviewed during scheduled training may be sufficient to address the education and training requirements for such small operators.

SCADA alarms are a key tool for managing pipeline operations, but excessive numbers of alarms can overwhelm controllers. This final rule will require pipeline operators to develop written alarm management plans. These plans must include monthly reviews of data points that have been taken off scan or have had forced or manual values for extended periods. Operators will also need to verify correct alarm set-points, eliminate erroneous alarms, and review their alarm management plans at least annually. Proposed requirements for weekly reviews of issues related to alarm management and specified elements to include in annual reviews were not incorporated in the final rule. Some elements that would have been included in those weekly reviews, particularly "nuisance alarms," have been generalized to points that have had alarms inhibited (which would likely result if nuisance alarms occur) or which have generated false alarms, both of which are now required to be included in monthly reviews. Operators will also be required to monitor the content and volume of activity being directed to their controllers (including alarms and actions directed to controllers from sources other than the SCADA system) at least annually.

Pipeline operators will be required to consider the effects of future changes to the pipeline on control room operations. They must involve controllers, controller representatives, or their management in planning prior to implementing significant hydraulic or configuration changes that could affect control room operations. This participation must be accomplished with enough time prior to the implementation to allow adequate training, procedure development and review by the affected controllers. Operators must also assure good communications when field personnel are implementing physical changes to pipeline equipment or configuration. Proposed requirements to track SCADA maintenance, coordinate SCADA changes in advance, and consider effects on control rooms in merger and acquisition plans have not been incorporated.

Mergers and acquisitions are events that can introduce changes of importance to controllers. Acquired assets are often added to existing SCADA systems, or divested assets are removed. Other changes in operating practices may occur as a result of management changes associated with a merger. The proposed rule would have required that merger, acquisition, and divestiture plans be developed and used to establish and conduct controller training and qualification prior to the implementation of any changes to the controller's responsibilities. A unique section regarding merger, acquisition, and divestiture plans for the control room has not been included in the final rule, because these types of plans frequently include many elements that do not affect control rooms and controllers. Nevertheless, PHMSA considers that operators should take into account potential implications on control rooms during such events. Other requirements of this rule address many of the important factors affecting control room operations and controllers in a merger, acquisition, or divestiture. For example, operators will be required to consider additional alarms added to a controller station to determine whether they could create a "flood" that would potentially overwhelm the controller. PHMSA expects that operators would also consider alarm descriptors and prioritization if changes are made to a controller console. Changes to SCADA systems to incorporate new (or delete old) assets would trigger requirements for display point validation and display design (i.e., required elements of API RP 1165). PHMSA thus considers that important changes associated with mergers, acquisitions, and divestitures are still addressed within this rule even though the proposed explicit requirement to address them in plans for these events has not been included.

Pipeline operators will be required to review their operating experience to identify lessons that might improve control room management. Specifically, operators will be required to review any reportable event and determine if control room actions contributed to the event. This is more focused than the proposed requirement that operators review all reported incidents. Operators must identify, from these reviews, aspects of the event that may reflect on controller fatigue, field equipment, operation of any relief device, procedures, SCADA system configuration, and SCADA system performance. Operators must include lessons learned in controller training programs. The proposed rule requirement for operators to review ''near misses'' or events that did not meet criteria for reporting was not adopted in this rulemaking action, but such reviews are certainly encouraged.

Pipeline operators will be required to have formal training programs including computer-based or non-computer (e.g., tabletop) simulations to train controllers to recognize and deal with abnormal events. The training must also provide controllers with a working knowledge of the pipeline system, particularly as it may affect the progression of abnormal events, and their communication responsibilities under the operator's emergency response plans. Proposed requirements that training include site-specific failure modes of equipment and site visits to a representative sample of field installations similar to those for which a controller is responsible were not adopted.

Operators must, upon request of pipeline safety regulators, submit their completed control room management programs to the regulator for review. This replaces the proposed requirement that executives of pipeline operating companies submit to regulators annually a signed validation that: Controller training has been reviewed, only qualified controllers have been allowed to operate the pipeline, and the company continues to seek ways to improve control room operations. A request to review the plan will usually be in the course of a regulatory inspection where the adequacy of control room management plans and training will be reviewed, as will the operator's compliance with each of the above-referenced requirements.

The proposed requirements related to a qualification program for controllers were not adopted. Controllers are still subject to existing requirements for operator qualification, which address similar subjects.

V. Response to the Comments

The responses to comments in this section reflect PHMSA's consideration of the Advisory Committees' recommendations as well as the individual comments in the docket. A review of all submitted comments shows that the comments submitted by trade associations (API, AOPL, INGAA, AGA, and APGA), jointly and individually, address the comments of almost all pipeline operators. Some comments were on the preamble to the proposed rule. These comments will not be responded to unless they are relevant to this rulemaking action. Comments that were beyond the scope of this rulemaking action are not being addressed.

A. Liquefied Natural Gas (LNG) Facilities

The joint trade associations; the Iowa Utilities Board; 11 LNG facility and gas pipeline operators; AGA; APGA; and one individual opposed addition of requirements into 49 CFR part 193 addressing LNG facilities.

AGA and the LNG facility operators stated that the LNG facilities should not be included in the final rule because: (1) It was not the intent of Congress or the NTSB to include LNG in this regulation; (2) Congress expressly limited the CCERT study in the Pipeline Safety Act of 2002 to three pipeline facilities; (3) LNG facilities were not to be included in the pilot study; (4) LNG facilities are operated as plant sites with local control rooms; (5) Almost all of the text in the proposed amendments to 49 CFR part 193 is copied verbatim from the language for gas and hazardous liquid pipelines, but many of the requirements that are logical for pipelines make no sense in operating LNG plants; (6) The agency's own Regulatory Impact Analysis (RIA) study of the proposed rule clearly demonstrates no benefit that would offset the cost of including LNG facilities in the NPRM; (7) LNG facilities are regulated by 49 CFR part 193 and NFPA 59A, as incorporated by reference; and (8) The very detailed proposed control room rule creates confusion when added to the existing regulations. AGA and the joint trade associations suggested that PHMSA should initiate a separate rulemaking action focused on issues relevant to LNG facilities if it concludes that control room management requirements are needed for these facilities.

Agency response—PHMSA agrees that the PIPES Act requirement regarding control room management does not explicitly refer to LNG facilities, nor are such facilities referenced in the PSIA legislation with regard to the controller certification pilot study. Similarly, NTSB did not address LNG facilities in its SCADA safety study and related recommendations. At the same time, neither Congress nor NTSB explicitly stated that control room management requirements should not be included for LNG facilities. Given the broad authority of PHMSA to regulate pipeline safety, including the safety of LNG facilities, the silence of the PIPES Act and the NTSB safety study with respect to LNG is not, by itself, a compelling reason why these facilities should be excluded from this rulemaking. However, through further review and consideration of the comments, PHMSA has determined that LNG should not be included in this rulemaking action at this time.

After considering the comments and re-evaluating the basis for applying the same requirements to part 193 for LNG facilities, PHMSA is persuaded that there are several reasons why we should not have used the same requirements. LNG facilities are different from pipelines. As pointed out by commenters, LNG facilities exist on a single site, rather than dispersed over hundreds or thousands of miles, and LNG controllers thus have different knowledge of and working responsibilities for facility equipment. LNG controllers can, and do, walk to ''field'' equipment within minutes to monitor its condition or take local operating actions, whereas pipeline controllers may ''interact'' with field equipment only via their SCADA systems. Because they operate equipment locally, LNG controllers have better operational knowledge of the equipment in their facilities, including its possible failure modes, than do most pipeline controllers. All of these differences diminish the value in improved safety that would result from implementing the proposed requirements at LNG facilities.

In addition, the regulations in part 193 do not parallel precisely those in the other parts. For example, part 193 includes specific requirements applicable to control centers [5] (49 CFR 193.2441) that were not in parts 192 or

[5] Control centers is the term used in part 193 to refer to what are called control rooms in this document.

195 prior to this rulemaking. This could create some degree of overlap, and potential confusion, if the requirements included in this final rule for Parts 192 and 195 were also incorporated into part 193. PHMSA thus has not included requirements for part 193 in this final rule.

B. Scope of the Rule and Related Definitions

AGA stated that the proposed definitions of controller and control room had the effect of unreasonably expanding the scope of all rule sections. AGA stated that the proposed rule would regulate local, remote or field control rooms, panels and devices, but noted that local, remote or field control rooms are usually hardwired instead of operated via long-distance communications through SCADA. Because a controller or a technician can address problems and concerns with a few minutes' walk in these facilities, AGA contended local control rooms do not need the complicated procedures placed in this proposed rule.

Other commenters agreed that the proposed definitions of ''controller'' and ''control room'' were unreasonably broad and that they led to a scope that was broader than necessary. The Iowa Utilities Board (Iowa) stated that by defining a controller as someone who monitors ''or'' controls, instead of monitors ''and'' controls, the scope of the rule would unreasonably expand to include any facility with a pressure gauge, and any person who checks the pressure gauge. The joint trade associations' alternative regulatory language included revisions to definitions. Their alternate definitions for ''controller'' and ''control room'' are based on API RP 1168. API and AOPL also stated that the NPRM definitions for ''controller'' and ''control room'' are too broad. They recommended the agency adopt the API RP 1168 definitions for ''controller'' and ''control room'' as proposed in the joint trade associations' alternate language. Iowa agreed that the definition of controller and control room should be based on the definitions in API RP 1168. Iowa also suggested that the agency adopt the alternative regulatory language proposed by the trade associations. NAPSR proposed adopting the API RP 1168 control room and controller definitions to resolve the issue of jurisdictional authority for pipelines crossing state lines. The Missouri Public Service Commission (PSC) stated that it supports and concurs with the comments submitted by NAPSR. PSC also believes that the definitions of ''control room'' and ''controller'' noted in the NAPSR comments should be adopted in the rulemaking. All individual gas and hazardous liquids pipeline operators expressed similar concerns with the proposed rule definitions of ''controller'' and ''control room.''

INGAA stated that the proposed regulations far exceed what Congress intended regarding the range of subjects covered, the range of facilities covered and the range of employees covered.

The joint trade associations stated that the proposed rule had no scope statement to provide guidance regarding the application of the proposed rule. API and AOPL stated that the scope of the NPRM exceeds the intent of Congress. Individual pipeline operators echoed the comments of the joint trade associations and the individual trade associations. Many of the comment submitters are, like AGA, concerned with broad definitions of ''controller'' and ''control room.'' Also, some individuals commented that the scope of the proposed rule is too broad.

APGA stated that the proposed rule should be re-written to be limited to true pipeline controllers and made reasonable for those operators. APGA noted that many small gas distribution pipeline operators, including many of its members, do not have control rooms and controllers in the same sense as do larger pipeline operators.

Agency response—PHMSA agrees that the proposed definitions of ''controller'' and ''control room'' had a rather pervasive effect on the scope of the requirements in the rule. In particular, PHMSA agrees with the Iowa Utilities Board that the proposed language could have been read to include personnel who monitor a pressure gauge (or other instrument) but have no authority or responsibility for pipeline operation. This result was unintended. PHMSA did not intend these requirements to apply to persons who may use SCADA information for non-operational reasons, but rather to persons with operational duties and responsibilities that involve use of SCADA and who thus can directly effect on pipeline safety. PHMSA has made changes in the definitions in the final rule to clarify this intent.

The inclusion of field control rooms and local control panels, however, was intended. The proposed rule was intended to apply to these control operations, in situations in which the person performing local control actions could not actually see the effect of those actions, based on the premise that the cognitive issues related to use of local computer-based controls were similar to those associated with use of SCADA in remote control rooms. PHMSA is persuaded by its review of the public comments that while cognitive issues may be similar, the potential effect on safety that could result from use of local computer-based controls are much less. As a result, PHMSA has modified the final rule to remove explicit requirements that local control panels be included in the actions required by this rule. Local control panels and field control rooms will only be included if they meet the definitions included in this rule, i.e., if they can have an effect on pipeline safety similar to that of a non-local control room.

By revising the definition of control room in response to the comments, the agency has also limited the scope to control rooms with SCADA systems. In addition, the wording in the proposed definition is changed from ''monitoring or controlling'' to ''monitoring and controlling.'' It should be noted that a control room whose SCADA system is used only to monitor incoming data is still included in the requirements of the rule if the controllers otherwise act to ''control'' the pipeline. Some control rooms have only monitoring capability in their SCADA system, but they achieve control through controllers responding to incoming data by other means such as by contacting field personnel and directing them to take action when necessary. If controllers prompt others to action (or perform those control action themselves) they are considered to ''control'' the pipeline. Therefore, the change from ''or'' to ''and'' does not exclude monitor-only control rooms from the scope of this rulemaking action. The change from ''or'' to ''and'' principally excludes individuals who may access and monitor SCADA system data for non-controller, incidental reasons, such as maintenance planning, equipment efficiency, or business logistics purposes. These persons cannot directly affect pipeline safety, because they are unable to use the SCADA system to take any controller actions.

With respect to the definition of controller, the agency similarly narrowed the scope to eliminate persons who only use SCADA data incidentally and thus cannot directly affect pipeline safety. The definition now includes only those persons who monitor SCADA data from a control room and have ''operational authority and accountability for the remote operational functions of the pipeline facility as defined by the pipeline operator.'' As in the case of ''control room,'' the definition of ''controller'' has been modified from ''monitor or control'' to ''monitor and control.'' If a

SCADA system is designed and used in a control room only for monitoring purposes, and the individual contacts other personnel to initiate corrective actions after monitoring the SCADA system, that person is considered a controller.

PHMSA considers that these changes to the definitions of ''control room'' and ''controller'' limit the scope of the proposed rule to those persons and operating centers that can directly affect pipeline safety. Most importantly, they eliminate the unintended apparent inclusion of certain employees who use SCADA data only incidentally. PHMSA considers that the revised definitions still encompass the majority of employees and control centers that were intended as the focus of this rulemaking. The changes in definitions address most, but not all comments concerning scope.

PHMSA has revised the final rule to include a statement of scope to clarify that it applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. PHMSA has also revised the rule to exclude operators of some smaller gas pipeline systems from many of the rule's provisions. Specifically, gas distribution operators with less than 250,000 services and gas transmission operators without compressor stations are required only to comply with the provisions related to fatigue mitigation, validation, and compliance and deviation. These small and simple pipelines require far less controller action, obviating the need for the other provisions. There are often few or no actions that controllers of small distribution systems can take remotely. These systems operate at low pressures, providing significant time to identify and respond to unusual situations before any safety problem could result. Similarly, there are few actions that a controller of a transmission pipeline that does not include compressor stations can take to adversely affect safety. Most such pipelines are short. They often are the gas supply for local distribution companies, and are operated as an integral part of their distribution pipelines. They meet the definition of transmission pipelines because they operate above 20 percent SMYS or serve one of the functions included in the definition in section 192.3, but they represent a much smaller potential for safety issues. It should be noted, however, that this limited exclusion applies only if the operations from a gas operator's control room are limited to such smaller operations. The full requirements of the rule apply to operators of such pipelines if the operator also operates other pipelines outside of this limited exclusion from the same control room. For example, there may be large gas transmission operators who also operate small distribution pipelines or large LDCs that also have or operate transmission without compressors. In such cases, all the provisions of this rule apply to all of the operator's pipeline operations from a common control room.

C. Other Definitions

The joint trade associations proposed changes to the definition of SCADA systems. The proposed rule would have defined these as ''a computer-based system that gathers field data, provides a structured view of pipeline system or facility operations, and may provide a means to control pipeline operations.'' This definition would have encompassed computer-based control systems in the field. The trade associations proposed that this definition be limited to systems used by controllers in the control room. This change is related to the concern over scope and the definition of ''controller'' and ''control room'' described above. The joint trade associations would also focus the definition of ''alarm'' on safety-related parameters, omitting reference to indications that operational parameters not related to safety are outside expected conditions.

INGAA stated that the definition of ''alarm'' is not required or even contemplated by Congress for gas transmission pipelines and, therefore, should be deleted. On the definition of SCADA system, INGAA recommended that the agency adopt the definition provided by the joint trade associations.

Agency response—Alarm management is a significant factor in control room management and is thus included in this rule. Excessive numbers of alarms or alarms that are inaccurate or not prioritized can overwhelm a controller, resulting in a failure to take appropriate action. Assuring appropriate management of control room alarms requires that the alarms of concern be defined. At the same time, PHMSA understands the industry's concern that SCADA systems are used to alarm many parameters that do not affect safety and that response to these parameters is outside what should be PHMSA's concern. Accordingly, PHMSA has revised the definition in the final rule to reflect that alarms of concern are those providing either or both audible and visible indications to controllers that equipment or processes are outside operator-defined, safety-related parameters. However, the final rule will require that operators monitor the content and volume of activity being directed to each controller.

The final rule defines SCADA systems as a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline. This excludes local computer-based control stations for the reasons described above. Also as discussed above, control may be exercised by a controller notifying other personnel to take action. Control may also be accomplished through SCADA commands. The key factor is that the system provides information that allows control to occur, and systems that cannot send commands to operate pipeline equipment may thus still be SCADA systems under this definition.

D. Regulatory Analysis

The joint trade associations stated that the preamble statement vastly underestimates the cost of the proposed regulations. They stated that the proposed rule would cost more than $100 million annually and that the preliminary regulatory analyses should have concluded that this was an economically significant rule under section 3(f)(1) of Executive Order 12866 (58 FR 51735; October 4, 1993) and DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979). Also, they stated that the proposed rule has a significant regulatory impact within the meaning of 5 U.S.C. 601 *et seq.* They contended the proposed rule is contrary to the Unfunded Mandates Reform Act of 1995 because a large portion of gas distribution systems are owned and operated by municipalities and local governments. In addition, the associations maintained that the proposed rule would impose substantial costs to state and local governments contrary to Executive Order 13132.

AGA stated that its review of the proposed rule shows obvious errors in the analysis. AGA stated that it obtained rough estimates from some of its LDC members that show the proposed rule to be not cost beneficial on a national basis, and that it will exceed the $100 million in annual costs threshold of a significant rule. AGA stated that a comparison of implementation costs between the proposed rule and that of the alternative regulatory language proposed by the joint trade associations shows the costs of the alternative regulatory language are approximately

14 to 15 percent of the costs of the proposed rule.

INGAA stated that the benefits of the proposed rule for the gas transmission companies are unworthy of a rulemaking compared to the expected annual costs for the next 10 years of nearly $140,000,000.[6] INGAA contends a handful of anecdotal data from an appendix to an unrelated study, some answers to hypothetical questions about theoretical possibilities and a series of assumptions with no foundation in the record do not constitute a legally defensible foundation for imposing detailed and costly regulations on the gas transmission pipeline industry.

API and AOPL stated that they asked their members to comment on the number of employees that would be covered under the definition of ''controller'' provided in the proposed rule; the aggregated cost estimate for training and qualifying these additional employees; and the estimated cost of point-to-point verification today and the projected estimate under the proposed rule. They stated that the cost estimates vary from operator to operator, but what each operator had in common was a tremendous increase in the number of additional employees that would need to be trained and qualified at an exorbitant cost. They stated that estimates on the increased number of employees under the proposed rule range from four times as many employees to train and qualify to more than ten times the current number of ''traditional controllers.'' The initial training and qualification costs ranged from $1.2 million to more than $5 million per operator with operators calculating these costs in a number of ways. The annual re-qualification costs would average $500,000 per operator. The point-to-point verification cost estimates averaged $500,000 per operator. They stated that one of their members included lost revenue from having to shut down the pump station, breakout storage tank areas, terminal deliveries and other hard assets in order to complete the point-to-point test. Also, they stated that the RIA did not have estimates for Alarm management and Qualification. They stated that a company estimated that it would cost $52,000 per year to review SCADA operations at least once a week as proposed, and evaluating a controller's physical abilities and implementing methods to address gradual degradation would cost $60,000 initially for 400 controllers and $8,000 annually thereafter.

Agency response—PHMSA has revised the regulatory analysis based on the revised scope of the rule, relevant comments received, and industry-submitted cost estimates. The scope of the rule is narrowed to exclude some gas LDCs and some gas transmission operators from most requirements in this rulemaking action. In addition, many of the individual requirements have been narrowed.

PHMSA concludes that the widely varying estimates of cost between our RIA and industry estimates resulted largely from confusion concerning the definition of a controller. As discussed above, the definition in the proposed rule had the unintended effect of appearing to encompass pipeline operator employees who use SCADA data but have no operational responsibilities for the pipeline. This significantly increased the number of employees that would have been subject to the requirements affecting controllers (e.g., fatigue mitigation, training and qualification). PHMSA agrees that applying these requirements to a much larger number of personnel would incur costs significantly higher than estimated in the RIA. The revised definition in the final rule focuses the requirements on controllers working in control rooms with operational responsibility—and the revised RIA uses a more-realistic estimate of the numbers of these personnel that will be affected.

Changes made in the final rule also significantly reduced the cost of elements not depending on the number of controllers affected. A major cost element was the proposed requirement for a one-time, 100 percent verification of SCADA systems. Commenters pointed out that this requirement would have involved significant costs for very little benefit. It is unlikely that such a ''baseline'' verification would have identified significant problems that could affect safety. This is because SCADA systems are already installed and in use by operators, so readings have already been verified and problems of any significance would likely have surfaced in the normal course of using a SCADA system over time. Thus, PHMSA agrees that the significant effort that would be required for a 100 percent baseline verification is unlikely to result in commensurate safety benefit, and so the final rule eliminates that requirement. It requires, instead, that SCADA displays be verified when field equipment monitored by SCADA is moved or when other changes that affect pipeline safety are made to field equipment or displays. These kinds of changes can introduce errors that would affect subsequent SCADA operations. For this reason, SCADA information is typically verified when making these types of changes, to assure that the changes have been implemented properly and that all equipment is functioning as intended once work is completed. As a result, this re-focused SCADA verification requirement imposes much lower additional costs. It essentially has the effect of requiring that all pipeline operators take the same actions that a conscientious operator would take even if no requirement existed.

The scope of required alarm verifications is also significantly reduced in this final rule. Commenters suggested that they would need to hire additional staff solely to perform the weekly and monthly reviews that would have been required by the proposed rule. PHMSA is persuaded that the alarm conditions are unlikely to change so much on a weekly basis, absent some significant ''event,'' that a thorough review would be needed on such a frequency. Response to an event would typically include the effect that the event may have had on alarms. The final rule has reduced these requirements to a monthly review of more-limited scope and an annual review of the alarm management plan, significantly reducing expected costs.

The revised RIA considers the changes in scope of the final rule and concludes that the rule is cost-beneficial.

E. Roles and Responsibilities

AGA stated that Congress intended for pipeline operators, not the agency, to write their control room management plans due to the diversity of control rooms. AGA stated that PHMSA should not dictate to an operator what responsibilities and tasks should be written into an operator's plan, which AGA considered was the effect of the specific elements included in the proposed rule.

API and AOPL supported the language in Paragraphs (b)(1)–(3) of the proposed rule (decision making during normal operations, role during abnormal events, and emergency role) and recommended deletion of paragraphs (b)(4) and (b)(5) (responsibility to coordinate with other operators having pipelines in common corridors and shift change). API and AOPL stated that operators currently maintain Emergency Response plans that address multi-pipeline corridors and appropriate notification and response procedures. They stated that these roles and responsibilities for controllers and other

[6] INGAA provided estimated implementation costs for selected requirements of the proposed rule at initial cost of $262,986,000 and annually at $139,798,000.

field personnel are clearly defined in the notification and response procedures. They believed that PHMSA might find API RP 1168 useful in developing control room management programs related to roles and responsibilities.

INGAA stated that this section should be deleted in its entirety because it runs counter to congressional direction and PHMSA's authority under Section 12 of the PIPES Act.

Agency response—PHMSA agrees that it is appropriate for operators to define roles and responsibilities for controllers, because of the many varied circumstances of different pipelines, their control rooms, and their operating practices. The proposed rule would have required that operators define these roles and responsibilities, and this has been retained in the final rule. The proposed rule went on to list certain roles and responsibilities that operators were to include in their definition. These have been deleted. PHMSA will verify during inspections that operators have appropriately defined the roles and responsibilities for their controllers.

PHMSA acknowledges API/AOPL's support of the proposed elements addressing normal operations, abnormal operations, and emergencies. These elements have been retained in the final 192.631(b) and 195.446(b) (**Note:** For editorial purposes PHMSA has moved the requirements proposed as § 195.454 to § 195.446). PHMSA also acknowledges the concerns expressed by AGA and gas pipeline operators that these elements tend to dictate the content (in part) of the roles and responsibilities the operator must define; however, PHMSA considers it essential that an operator's defined roles and responsibilities address normal, abnormal, and emergency operating conditions. The final rule does not include specific responsibilities for each of these conditions, but does require that the operator's definition consider them all.

PHMSA disagrees that it is not necessary to address shift change. Experience has shown the importance of controlling the transfer of information between controllers. Incidents, accidents, and other problems have occurred because of inadequate shift change. PHMSA has deleted the specific alternative mechanisms for recording a shift change that were included in the proposed rule (a system log-in feature or recording in shift records), but the final rule still requires that operators establish a method of recording controller shift changes. Operators are also required to define the information that controllers must discuss or exchange during shift changes and other instances in which another controller assumes responsibility.

F. Providing Adequate Information

AGA disagrees with periodic point-to-point verification requirements except to show that the SCADA system displays accurately depict field configuration when any modification affecting safety is made to field equipment or applicable software, and when new field equipment is installed.

INGAA stated that "Adequate" would seem to include those points that affect pipeline safety, and not each of the points that collect information about the pipeline which are completely unrelated to safety. INGAA estimates the safety-related points to be significantly outnumbered by the non-safety-related points.

API and AOPL stated that their members' experience shows that re-verification offers few safety benefits in return for the large investment in SCADA system and field resources that would be required. They suggested the emphasis of the regulation should be on management of change, rather than re-verification.

The proposed requirement to implement API RP 1165 for SCADA displays also caused concern. Pipeline operators objected to the requirement to apply the standard to existing displays, noting that controllers have been trained and have experience in using existing systems and that any benefit from implementing the standard would likely be small. Other operators objected to the incorporation of the standard or suggested that alternatives be allowed. AGA and several operators suggested that operators be required to implement the "general" requirements of the standard.

INGAA commented that the "critical" information required to be exchanged during shift changes required more definition. Some pipeline operators objected to the proposed requirement to provide an overlap between shifts to allow for shift change. API and AOPL suggested that PHMSA consider adopting API RP 1168 to govern shift change requirements.

Agency response—PHMSA has eliminated from the final rule the proposed requirement to perform 100 percent baseline verification of SCADA systems. PHMSA has also eliminated the proposed requirement that operators plan for systematic re-verification. As discussed above (see paragraph D of this section), PHMSA concluded that a baseline verification was unlikely to identify safety-related problems that had not already been recognized through normal operations. Similarly, new problems are likely to be identified as part of normal work before a re-verification would find them. As a result, the significant effort that would be required to implement these two requirements would result in little foreseen safety benefit. The final rule requires that operators verify SCADA when changes are made that can affect the information displayed by SCADA. SCADA problems are most likely to be introduced when making changes and verification that the SCADA system functions as intended are a means of identifying such problems.

With respect to API RP 1165, PHMSA agrees that applying the standard to existing displays is likely to lead to little safety benefit for the cost incurred, since controllers have already been trained and are experienced in using existing displays in their current operations. In addition, changes made to existing displays would require retraining of controllers and could introduce confusion unnecessarily. When displays are changed, however, retraining will be needed because of the change and the reasons for not disrupting controllers' use of displays with which they are familiar no longer apply. PHMSA has limited the requirement to apply the standard to displays that are added, expanded or replaced after the date by which the control room management procedures required by this rule must be implemented. For gas pipelines, the final rule requires that only certain sections of the standard be implemented. The cited sections address the aspects that are most important to assuring that displays are configured to be most useful to controllers for managing safe pipeline operations, including human factors engineering. PHMSA is not aware of equivalent standards that would accomplish the same purpose, and has not provided for an alternative. Flexibility is available in that operators need not implement a provision of API RP 1165 if they demonstrate that the provision is not practical for the SCADA system used.

PHMSA has eliminated the requirement to provide for overlap of shifts to facilitate shift turnover. Overlaps will likely be needed to accommodate the need to transfer information to an oncoming controller. The transfer of information is required, obviating the need to specify an overlap requirement in the regulation. The final rule for gas pipeline operators requires that operators establish procedures for when a different controller assumes responsibility, including the content of information that must be exchanged, but has deleted the requirement that ''critical'' information must be included. It will be up to operators to define the information that is important to impart to oncoming controllers. API RP 1168 provides guidance that can assist in this definition. This standard is incorporated by reference for this purpose for hazardous liquid pipeline operators. PHMSA will verify during inspections that operators have included in their definitions the information needed by their controllers to assure pipeline safety.

G. Fatigue Mitigation

The National Transportation Safety Board (NTSB) stated that it does not believe the proposed rule satisfactorily addresses mitigation of controller fatigue. NTSB stated that the proposed rule should require operators of pipeline facilities to incorporate fatigue research, circadian rhythms, and sleep and rest requirements when establishing a maximum limit on controller shift length, maximum limit on controller hours of service, and schedule rotations. Also, NTSB stated that it would like PHMSA to provide additional information about the agency's criteria for evaluating operators' plans and to explain how the agency intends to monitor the effectiveness of implementing those plans on fatigue mitigation.

Some individuals suggested that the proposed rule does not go far enough. Some suggested a need for a uniform maximum hours of work limit to be established in the regulations. These individuals stated that the rule needs to set standards to decrease the likelihood of controller fatigue rather than passing that duty on to operators. They stated that the proposed rule does not set standards regarding fixed versus rotating shifts and does not set standards for the length of each rotation. One individual suggested setting shifts at ten hours with two hours overlap between beginning and end of shifts and with a three consecutive day break. Some suggested using part-time workers to overlap 12 hour shifts. One stated that the agency should redraft the vague provisions found in the shift change and fatigue sections and should provide more specific examples for the pipeline operators to adequately comply with the rule. One individual stated that for the proposed rule to increase vigilance and mitigate fatigue, the agency must address boredom and monotony. One suggested that the agency should consider methods that specifically address mental fatigue and an adrenaline response training program for all pipeline workers.

Other citizens supported the proposed rule on fatigue mitigation. One stated that fatigue management should be implemented on an intra-company basis based on the individual needs of the controllers rather than on an industry-wide scale. Others commended the agency for not prescribing a maximum hours of work limit. Some supported the need for testing of physical and visual abilities for controllers. One individual suggested a requirement for controllers to check if they are physically fit to perform the tasks assigned. One individual suggested implementing a requirement that workers make observational entries every quarter hour to ensure that they remain engaged in their duties and maintain continual mental vigilance throughout a shift.

AGA objected to requiring that operators implement additional measures to monitor for fatigue when a single controller is on duty. AGA stated that the gas distribution industry's safety record has demonstrated that a single controller can safely operate a pipeline.

API and AOPL suggested that PHMSA modify paragraph (d) of the proposed rule to reflect that despite reasonable fatigue mitigation measures the operator may not be able to ''prevent'' fatigue from occurring. Also, they encouraged PHMSA to consider adopting the language in Section 6 of API RP 1168 on Fatigue Management.

INGAA stated that the joint trade associations' substitute rule addresses fatigue. INGAA stated that it urges adoption of these provisions along with the rest of the substitute rule.

Agency response—Fatigue can be an important factor affecting controller performance. NTSB has recommended that PHMSA establish requirements in this area, and the PIPES Act requires that operator human factors plans include a maximum hours of service limit. Fatigue is something that affects all people at some time and many individual comment submitters have suggested ways in dealing with this issue. Nonetheless, PHMSA agrees that it is difficult to establish and enforce regulations that ''prevent'' fatigue. In this final rule, PHMSA requires that operators implement methods to reduce the risks associated with fatigue.

Pipeline operators will be required to comply with a maximum hours of service limit. This rule does not establish such a limit, but rather requires that each operator establish a reasonable limit for itself. This will allow consideration of factors that may be unique to the operation of particular pipelines. Experience has also shown that deviations from normal scheduling (e.g., requiring a controller to work a double shift due to unexpected absence) can result in excessive fatigue; establishing a limit will have the effect of reducing the occurrence of these deviations.

At the same time, PHMSA recognizes there may be infrequent emergencies during which an operator may find the need to deviate from the maximum limit it has established to ensure adequate coverage in the control room for emergency response. Accordingly, the regulation provides that an operator's procedures may provide for the deviation from the maximum limit in the case of an emergency. Such a deviation would only be permitted if necessary for the safe operation of the pipeline facility. PHMSA or the head of the appropriate State agency, as the case may be, may review the reasonableness of any deviation from an operator's maximum limit on hours of service when considering whether to take enforcement action.

PHMSA has not included an explicit requirement that operators incorporate fatigue research and circadian rhythms when establishing their limits. Operators will be expected to have a scientific basis for the limit they select. PHMSA expects that operators will consider circadian effects, need for rest, and other factors highlighted by relevant research, but PHMSA sees no benefit in including general references to these factors in this rule. PHMSA has included in this final rule a requirement that shift lengths and schedule rotations provide controllers sufficient off-duty time to achieve eight hours of continuous sleep. This addresses NTSB's concerns that sleep and rest needs to be accommodated. PHMSA has already issued an advisory bulletin providing guidance to pipeline operators on ways to manage fatigue,[7] and may issue additional guidance if new research, operational experience, or other factors indicate a need to do so.

PHMSA has not yet developed criteria for reviewing operator-developed hours of service limits and human factors management procedures, but plans to develop inspection criteria.

PHMSA has not included in this final rule a requirement to provide additional measures to address fatigue in situations where a single controller is on duty. Operators will need to address single-controller situations in their fatigue management plans, but no particular additional measures are required to monitor fatigue of a single controller at this time.

[7] ADB–05–06, August 11, 2005 (70 FR 46917).

H. Alarm Management

AGA stated that the proposed rule for alarm management is overly prescriptive. AGA requested that language be written at a high level to account for the diversity of control room systems used by different operators.

API and AOPL stated that they believe the alarm management requirement of the proposed rule is too prescriptive and will not result in an application of ''best practices'' as currently written. API and AOPL suggested that PHMSA require each operator to maintain an alarm management plan based on currently accepted industry practices. They stated that the plan should be based on a company's risk assessment related to alarm management and include regular audits and reviews of the alarm system performance to identify areas for training and improvement. They also stated that a company should assess risks associated with alarming and modify its program as needed on a less frequent basis.

INGAA stated that this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act and because it will not increase pipeline safety. INGAA urged the agency to adopt the joint trade associations' substitute rule for alarm management. INGAA also contended that the requirement would be very costly to implement.

Agency response—The alarm management provisions included in the NPRM were prescriptive and required frequent reviews. In addition, some of the required review elements would have been difficult to identify. For example, weekly reviews would have been required to include events that should have resulted in alarms but did not. Such events could be identified using SCADA data (even though they did not produce alarms) but would have required detailed review to do so. PHMSA is persuaded by the comments that the proposed provisions would have been burdensome and might not necessarily have addressed factors important for alarm management in particular pipeline control rooms. Instead, PHMSA has adopted the suggestions to require that each operator have an alarm management plan. Operators will develop those plans in recognition of issues that have proven important to their operations.

The final rule continues to require that alarm management plans include some critical elements. Foremost among these is a monthly review of points impacting safety that are not providing current data to controllers or points that may be triggering erroneous alarms. Operators respond to problems that occur in SCADA systems (and which can result in inaccurate information being displayed) by taking the points ''off scan,'' which means operators manually ''force'' certain information to be displayed. Controllers are generally made aware that the affected data is not timely and accurate, but the forced values (or no values at all) help prevent confusion. Operators return the data points to normal operation once the problems with the SCADA system have been identified and corrected. Generally, SCADA systems involve many data points (often thousands) and controllers are able to manage pipeline operations and respond to abnormal events even though some data is not current. Still, PHMSA considers it important that SCADA problems be addressed promptly, so that controllers have the most accurate and timely information with which to diagnose and respond to pipeline events. The monthly review is intended to assure that the need to address SCADA problems promptly is not lost in the crush of other activities.

The final rule will also require that operators monitor the content and volume of activity being directed to each controller. This requirement is intended to identify so-called alarm ''floods,'' which can involve many alarms (often not relating to pipeline safety) occurring simultaneously or in a short period. Such floods can overwhelm the capability of a controller to recognize problems and events that may underlie the alarms, and thus delay prompt response. PHMSA accepts the point made by commenters that the agency should not be regulating use of SCADA alarms for purposes not related directly to pipeline safety, but still considers that it is important to assure that controllers' ability to respond appropriately to safety-related alarms is not compromised. The requirement to monitor for volume and content of activity is intended to do this. Operators who identify situations in which controllers are receiving more information or required to perform more activities than they can process and address will be expected to take appropriate corrective action in a timely fashion.

It is also critical that operators verify correct alarm set points and descriptions, review their alarm management plans regularly, but at least annually, and address deficiencies identified in their reviews. Accordingly, these elements are also included in the final rule.

I. Operating Experience

AGA requested that the proposed requirements related to review of operating experience be deleted in their entirety, because AGA contended that they are duplicative of other sections in 49 CFR parts 191 and 192. AGA, INGAA, and others also objected to the proposed requirement that operators establish a threshold for near-miss events (i.e., events of some significance but which do not meet criteria for reporting to regulators as an incident) and include them in periodic reviews. The comments noted that this concept is impractical and would be difficult to enforce, that it effectively elevates these ''near-miss'' events to equality with incidents requiring reporting, and that it would add significant additional burden for very little benefit.

INGAA stated that this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act and because it will not increase pipeline safety.

API and AOPL suggested deleting requirements associated with the need to review accuracy, timeliness and portrayal of field information on SCADA displays and review of events that do not meet the threshold for reporting as accidents.

One individual commented that having controllers review non-reportable events, along with other activities that this rule is imposing on controllers, would require an excessive amount of valuable time.

Agency response—PHMSA does not agree that the proposed review requirements duplicate existing requirements. The requirements in this rule will build on existing requirements to identify and report incidents that meet certain criteria. PHMSA recognizes that those regulations require that operators review events to identify information that must be reported. The requirements in this rule are focused on identifying the effect of operational events on controllers, controller workload, and the ability of controllers to manage pipeline operations safely. PHMSA expects that these additional considerations will be included in the reviews of incidents currently conducted. Adding these considerations to existing reviews should result in minimal additional burden, but will help improve safe pipeline operations. The final rule will require that operators consider, in their reviews of reportable events, deficiencies relating to controller fatigue, field equipment, the operation of any relief device, SCADA system configuration, and SCADA performance. Operators will be required to incorporate lessons learned from these reviews into controller training programs.

PHMSA is persuaded that the requirement to conduct similar reviews for events that do not meet reporting criteria (i.e., near-miss events) is not necessary at this time. These events are not subject to reviews related to the need to submit information concerning the event, because operators are not required to report them. Accordingly, the entire review effort would be additional, rather than control-room considerations being a minimal addition of effort to an already-required review. Furthermore, these events have less safety significance than those that must be reported. The proposed provision to review near-miss events for control room lessons has thus not been included in the final rule, but PHMSA encourages operators to use near-miss information to advance pipeline safety.

J. Change Management

AGA requested that change management be removed from the proposed rule. AGA stated that the concept is best left to individuals familiar with an operator's entire operations and maintenance manual. AGA further stated that the person managing operations and maintenance should address the changes that can impact the job of a controller or any pipeline function. AGA stated that since most changes to a pipeline system have nothing to do with controllers, the change management concept should not be introduced into pipeline safety through a control room management rule.

API and AOPL recommended that PHMSA consider replacing the proposed language concerning change management with the language contained in Section 7 of API RP 1168. They stated that the proposed language is too prescriptive, would cause delays in implementation, and result in additional costs with no real benefit to justify these additional procedures.

INGAA stated that this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act, and because it will not increase pipeline safety.

Agency response—Not all pipeline changes affect controllers or control room operations. Some do, however, and it is important that controllers recognize that such changes are occurring, have sufficient training before they occur, and understand how they will affect the response of the pipeline to operational events. PHMSA has thus retained requirements for change management in the final rule.

At the same time, PHMSA agrees that the proposed requirements were too prescriptive and that pipeline operators should have flexibility in integrating change management into their organizational structure and business operations. The final rule requires that gas pipeline operators establish communications between control room representatives, management, and field personnel when planning and implementing physical changes to pipeline equipment or configurations. Operators must seek control room or control room management participation prior to implementing significant pipeline hydraulic or configuration changes. Field personnel will also be required to notify the controller when emergency conditions exist or when making field changes that affect control room operations. These requirements will assure that changes that could affect the ability of controllers to monitor the pipeline and assure safe operation are identified early so that training programs and procedures can be modified, if needed, and controllers can be made aware of changes that could affect their activities.

Operators of hazardous liquid pipelines will be required to implement change management provisions in Section 7 of API RP 1168. These are similar to the requirements for gas pipeline operators discussed above. PHMSA recognizes that Section 7 of API RP 1168, and other recommended practices incorporated by reference, commonly use the word ''should'' to denote a recommendation or that which is advised but not required. For example, paragraph 7.1 of API RP 1168 states that ''[p]ipeline control room personnel should be included in the project or change design and planning process.'' Where a standard incorporated by reference utilizes words of recommendation, such as ''should,'' an operator is expected to follow such provisions unless the operator has documented the technical basis for not implementing the recommendation. This has been PHMSA's position with regard to compliance with standards incorporated by reference that utilize words of recommendation. *See, e.g.,* 64 FR 15926, Apr. 2, 1999. In the above-referenced example, an operator would be expected to include control room personnel in the project or change design and planning process unless the operator can show the technical basis for why this could not occur.

K. Training and Qualification

A citizen suggested the use of videos instead of site visits for controllers. One individual suggested the use of a standardized examination for certification of controllers based on each pipeline's configuration, and a requirement for operators to consider the educational background of the individuals applying for a controller position. Another individual suggested controller feedback on training.

AGA requested that the Training section be deleted because 49 CFR part 192, subpart N provides operator qualification rules for all pipeline employees performing covered tasks.

INGAA stated that this section should be deleted in its entirety because it exceeds congressional direction and PHMSA's authority under Section 12 of the PIPES Act and because it will not increase pipeline safety.

API and AOPL stated that under the proposed rule's overly broad definitions of ''controller'' and ''control room,'' operators would have to expend considerable resources to meet the proposed requirements. They suggested deleting some sections from the proposed rule.

One individual agreed with an industry practice of a three year re-qualification period rather than annual re-qualification as proposed by PHMSA.

Agency response—Training is an important element of this rule. In many ways, training needs for controllers are different from those for other pipeline employees. Existing operator qualification requirements (subpart N of part 192 and subpart G of part 195) address training and qualification for specific tasks meeting certain criteria (called ''covered tasks''). Controllers require training that goes beyond specific tasks. They must be able to recognize abnormal and emergency events from the indications and alarms that these events will produce through SCADA. NTSB has recognized that controllers need this training and has recommended that PHMSA establish requirements for controller training that include simulator or non-computerized (e.g., tabletop exercises) training to recognize abnormal operating conditions, in particular leak events. The PIPES Act mandates that PHMSA implement standards in response to this NTSB recommendation. Accordingly, PHMSA has included such training requirements in this final rule.

PHMSA has revised the final rule to eliminate some of the specific elements that the proposed rule would have required to be included in this training. In particular, PHMSA has eliminated the requirements that controller training include site visits to a representative sample of pipeline facilities similar to those for which the controller is responsible and that controllers receive hydraulic training sufficient to attain a thorough knowledge of the pipeline system. PHMSA agrees that these proposed requirements would have entailed benefit that was difficult to quantify. A site visit, for example, might impart some knowledge concerning what is required to operate equipment at the site but would be unlikely to result in lasting detailed knowledge about equipment operation and the potential effects of equipment failures. Instead, the final rule requires that controller training be sufficient to obtain a working knowledge of the pipeline system, especially during the development of abnormal conditions. Controller training must also include use of simulators or non-computerized simulations for training in identification of abnormal operating conditions. These requirements will assure that controllers receive the training recommended by NTSB, and required by the PIPES Act, while allowing operators flexibility to design training programs that fit their operations.

L. Executive Validation

AGA requested that the senior executive validation requirements be removed from the rule. AGA commented that since the executive cannot approve the plan on the agency's behalf, it is not logical for the executive to independently approve the plan just to have the agency subsequently approve or reject the plan.

API and AOPL stated that they would like to work with PHMSA to more clearly define operator accountability. They stated that the paragraph, as currently worded with ''senior executive officer,'' is inappropriate. They stated that the definition of ''senior executive officer'' differs among operators, and API and AOPL would like to better understand what the term means to PHMSA. They stated that many of their members also commented that verifying that ergonomic and fatigue factors continue to be addressed or that controllers are involved in finding ways to improve safety is more appropriate for a lower level of management than what would constitute a ''senior executive officer.'' Even if it were appropriate for executive signoff, they said they believe the current language of the proposed amendments is too narrow and specific.

INGAA stated that requirements for executive validation should be deleted in their entirety. INGAA said this section is inconsistent with congressional direction and will not increase pipeline safety. INGAA stated that it understands the value of the proposed requirement to validate that the requirements of this rule have been implemented, since it could engender increased confidence and oversight of the respective control rooms and associated processes.

INGAA stated that it sees no demonstrable safety benefit discussed in the proposed rule and there are no tangible benefits to be gained by promulgating this section.

One individual stated that the senior executive officer validation should be required every three years.

Agency response—The purpose of this proposed provision was to assure management attention to control room issues. A senior executive would have been required to certify annually that the operator had reviewed controller training and qualification programs and found them adequate, that only qualified controllers had been allowed to operate the pipeline, that the requirements of this rule had been complied with, that the operator continued to address fatigue and ergonomic issues, and that controllers were involved in continuing efforts to sustain and improve safety. This was not intended to substitute for approval of a plan by the regulator, but rather to assure that a plan submitted to the regulator had obtained appropriate management approval within the operator's organization.

PHMSA agrees with commenters that it is likely that specific actions included within the proposed verification would be performed by lower-level managers and staff. The extent of actions that might have been required (or implied) was unclear in some cases. For example, ergonomic issues are not otherwise addressed in the proposed rule, but only in the proposed requirement that a senior officer certify that they were continuing to be addressed. PHMSA has, therefore, decided not to include the proposed requirement for periodic management certification in this rulemaking action.

PHMSA has included in this final rule a requirement that operators, upon request, must submit their completed control room management plans to PHMSA or, in the case of an intrastate pipeline facility regulated by the state, to the appropriate state agency. PHMSA expects that regulators (state or PHMSA) will generally review plans, and compliance with the requirements of this final rule, through the regular inspection process.

M. Qualification of Pipeline Personnel

INGAA stated that it supported the development of 49 CFR part 192, subpart N, when it was initially promulgated, and still believes it to be valid, including as it applies to controllers. Also, INGAA stated that it supports the use of the national consensus-based standard ASME B31Q, which addresses controller issues as well. INGAA stated that it does not see the need for a qualification section in this proposed rule, and notes the PIPES Act does not contemplate this section, either.

API and AOPL stated that they believe PHMSA would create confusion by keeping this particular paragraph in the final rule. They recommend that PHMSA delete proposed paragraph (i) and consider incorporating the requirements into the current subpart G—Qualification of Pipeline Personnel. They stated that if ''qualification'' refers to any other purpose than ''OQ'', then PHMSA needs to clarify that requirement. API and AOPL stated that they support the concept in paragraph (i)(2) of the proposed rule concerning evaluating a controller's physical abilities; however, they recommended that it be deleted because it creates confusion among operators until further research can be performed to develop standardized thresholds for the various physical attributes. Also, they stated their concern that compliance with the requirements in this paragraph could result in violation of the Americans with Disabilities Act.

AGA expressed concern that PHMSA is essentially rewriting the Operator Qualification rule. AGA stated that the two paragraphs for controller training and qualification are almost as long as 49 CFR part 192, subpart N, which provides operator qualification rules for all pipeline covered employees.

Agency response—PHMSA is persuaded by the comments to eliminate from this final rule specific requirements for periodic qualification of controllers, deferring to the existing operator qualification regulations in that regard. PHMSA recognizes, however, that certain changes to operators' controller qualification criteria will result from implementing the new requirements in this final rule and that operators will incorporate those changes, as necessary, into their qualification programs.

N. Implementation

The proposed rule would have established different deadlines for preparing and implementing control room management procedures, depending on the type of pipeline or control room. Proposed time frames varied from 12 to 30 months after publication of the final rule. Industry comments generally found the proposed time frames inappropriate. The draft alternative rule language submitted by the joint trade associations included a requirement that procedures be written within 18 months following publication of the final rule and be implemented within 3 years of publication.

Agency response—The elimination of local control stations from the final rule's scope, and its focus on control rooms using SCADA systems, makes it unnecessary to establish differing implementation schedules for control regimes of differing complexity. PHMSA agrees that the implementation time frames proposed by the joint trade associations would allow for a thorough process development phase before implementation, a familiarity with standards under development (such as International Society of Automation (ISA) 18.02 and API RP 1167), and an appropriate implementation time to promote consistency and understanding among operators. We have therefore, incorporated these time frames into the final rule.

VI. Regulatory Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. This rulemaking also carries out the mandates of the PIPES Act of 2006—to address human factors and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition (SCADA) systems (section 12) and to publish standards implementing certain NTSB recommendations (section 19).

B. Executive Order 12866 and DOT Policies and Procedures

This rulemaking action has been designated a significant regulatory action under Executive Order 12866 (58 FR 51735; Oct. 4, 1993). The rule is also a significant regulatory action under the U.S. Department of Transportation regulatory policies and procedures (44 FR 11034; Feb. 26, 1979) because of the substantial congressional, industry, and public interest in control room operations and human factors management plans. Therefore, the Office of Management and Budget (OMB) has reviewed a copy of this rulemaking.

The expected benefits of the rulemaking action are the reduction in pipeline incidents and accidents resulting from controller error and the associated societal costs that can be attributed to improved control room management and operations. The estimated benefits consist of two distinct measures: (1) The reduction in incidents and accidents due to errors attributed to control room personnel and (2) the reduction of societal costs related to those incidents and accidents that can be traced to factors related to control room operations management. Control room personnel errors can occur, for example, when a fatigued control room worker reads a pressure indicator incorrectly and increases pressure, leading to a pipeline rupture. Control room management errors occur when a procedure or process is not in place resulting in failure to detect an abnormal condition or a failure to respond to an incident or accident appropriately. For example, alarm systems may not be audited and an incident occurs that does not trigger an alarm. The remedial action (the rule) addresses both personnel error and operations management.

This rulemaking action is not expected to adversely affect the economy or the environment. For those costs and benefits that can be quantified the present value of net benefits, discounted at 7 percent, are expected to be about $6 million over a ten-year period after all of the requirements are implemented. This rule is also not expected to have an annual effect of more than $100 million on the national economy; therefore, the rule is not considered an economically significant regulatory action within the meaning of Executive Order 12866.

A complete RIA, including an analysis of costs and benefits, is available in the docket.

C. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether its rulemaking actions would have a significant economic impact on a substantial number of small entities. There were some changes going from the NPRM to the final rule that considered the concerns of small businesses. First, in response to industry's comments and to reduce the burden on small firms, PHMSA redefined the criteria to better differentiate between large operations that would be subject to all the requirements and those smaller operations that would have more limited regulation. PHMSA clarified the type of operators that would be affected by refining the definitions of controller and control room to determine which operators would need to be subject to the requirements. Then, PHMSA separated the operators based on risk to determine which operators needed to comply with the requirements. This redefinition reduced the number of requirements for small entities. Most small firms are now only required to comply with certain requirements mandated by law, namely fatigue mitigation (including training), and recordkeeping for compliance purposes.

Second, to better understand the distribution of systems based on size in the pipeline industry, PHMSA examined the operators' annual reports to further separate the firms by small, medium and large operations. The categories for this analysis were determined either by the number of pipeline miles, the number of customers served, or the complexity of the business. PHMSA has made every effort to limit the economic impact to small firms by taking steps to exempt gas distribution operators with fewer than 250,000 services from many of the requirements likely to have more than minimal cost impacts.

Based on the submission of annual reports, PHMSA estimates that there are 220 hazardous liquid (HL) system operators with fewer than 50 miles of pipeline that meet the definition of small entities. Also PHMSA estimated that 1,257 of 1,330 gas distribution systems and 475 of 950 transmission systems (for a total of 1,732 gas systems) fit the definition of a small operator.

The table below summarizes the expected compliance cost per small operator.

First-year costs		Annual recurring costs	
Low	High	Low	High
$6,000	$9,000	$2,300	$2,800

Although PHMSA does not have revenue data for the individual small pipeline operators, based on the most recent published operator revenue data, the estimated costs are significantly less than one percent of revenues for most firms and there is not likely to be a significant impact on a substantial small number of operators.[8]

Therefore, based on this information showing that the economic impact of this rule on small entities will be minor, I certify under section 605 of the Regulatory Flexibility Act that these regulations will not have a significant impact on a substantial number of small entities. The final Regulatory Flexibility Analysis is available in the docket.

D. Executive Order 13175

PHMSA has analyzed this rulemaking action according to Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because this rulemaking action would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

E. Paperwork Reduction Act

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), DOT will submit all necessary documents to request the Office of Management and Budget (OMB) grant approval for a new information collection. A copy of the analysis document will also be entered in the docket. The RIA contains detailed information on how PHMSA arrived at the cost and time estimates noted below.

This final rule contains information collection requirements that affect hazardous liquid and gas pipeline systems. The rule requires hazardous liquid and gas pipeline operators to keep records on the following sections: Control room management procedures; roles and responsibilities of pipeline controllers; information on SCADAs, fatigue mitigation; alarm management; change management; operating experience; training; compliance validation; and deviations. PHMSA estimates that it would take pipeline operators approximately 127,328 hours per year to comply with the rule's recordkeeping and record retention requirements. PHMSA estimates that the total costs are approximately between $4.3 million and $5.9 million the first-year and approximately between $4.2 million and $5.8 million in successive years. The RIA has the details on the estimates used in this analysis.

F. Unfunded Mandates Reform Act of 1995

This rulemaking action does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $141.3 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of this rulemaking action.

G. National Environmental Policy Act

PHMSA has analyzed this rulemaking action for the purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). The agency has determined that implementation of this rule will not have any significant impact on the quality of the human environment. The environmental assessment is available for review in the docket.

H. Executive Order 13132

PHMSA has analyzed this rulemaking action according to Executive Order 13132 (''Federalism''). The rulemaking action 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. This rulemaking action does not impose substantial direct compliance costs on State and local governments. Further, no consultation is needed to discuss the preemptive effect of the proposed rule. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

Transporting gas and hazardous liquids impacts the nation's available energy supply. However, this rulemaking action is not a ''significant energy action'' under Executive Order 13211 and is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, the Administrator of the Office of Information and Regulatory Affairs has not identified this rulemaking action as a significant energy action.

J. Privacy Act Statement

You may search the electronic form of comments received in response to any of our dockets by the name of the individual submitting the comment (or signing the comment if submitted for an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477).

List of Subjects

49 CFR Part 192

Incorporation by reference, Gas, Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 195

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

■ For the reasons set forth in the preamble, the Pipeline and Hazardous Materials Safety Administration is amending 49 CFR Chapter I as follows:

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

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

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, and 60137; and 49 CFR 1.53.

■ 2. In § 192.3, definitions for ''alarm,'' ''control room,'' ''controller,'' and ''Supervisory Control and Data Acquisition (SCADA) system'' are added in appropriate alphabetical order as follows:

§ 192.3 Definitions.

* * * * *

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller means a qualified individual who remotely monitors and

[8] *See: http://www.ibisworld.com/industry/retail.aspx?indid=1179&chid=1; http://www.ibisworld.com/industry/retail.aspx?indid=1184&chid=1; http://www.ibisworld.com/industry/retail.aspx?indid=1181&chid=1; http://www.bts.gov/publications/national_transportation_statistics/html/table_03_18.html.*

controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

* * * * *

Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

* * * * *

■ 3. Amend § 192.7 as follows:

■ a. In paragraph (b) add ''202–366–4595'' after ''20590–001;''

■ b. In the table in paragraph (c)(2), item B.(7) is added to read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(c) * * *

(2) * * *

Source and name of referenced material	49 CFR reference
* * * * * * *	
B. * * *	
(7) API Recommended Practice 1165 ''Recommended Practice for Pipeline SCADA Displays,'' (API RP 1165) First edition (January 2007).	§ 192.631(c)(1).
* * * * * * *	

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■ 4. In § 192.605, paragraph (b)(12) is added to read as follows:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(b) * * *

(12) Implementing the applicable control room management procedures required by § 192.631.

* * * * *

■ 5. In § 192.615, paragraph (a)(11) is added to read as follows:

§ 192.615 Emergency plans.

(a) * * *

(11) Actions required to be taken by a controller during an emergency in accordance with § 192.631.

* * * * *

■ 6. Section 192.631 is added to Subpart L to read as follows:

§ 192.631 Control room management.

(a) *General.*

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

(i) Distribution with less than 250,000 services, or

(ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§ 192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than Febraury 1, 2012.

(b) *Roles and responsibilities.* Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.

(c) *Provide adequate information.* Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see § 192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation.* Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management.* Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

(g) *Operating experience.* Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review incidents that must be reported pursuant to 49 CFR part 191 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) *Compliance validation.* Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviations.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 7. The authority citation for part 195 is amended to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60116, 60118, and 60137; and 49 CFR 1.53.

■ 8. In § 195.2, definitions for ''alarm,'' ''control room,'' ''controller,'' and ''Supervisory Control and Data Acquisition (SCADA) system'' are added in appropriate alphabetical order as follows:

§ 195.2 Definitions.

* * * * *

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

* * * * *

Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

* * * * *

Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

* * * * *

■ 9. Amend 195.3 as follows:

■ a. In paragraph (b) add ''202–366–4595'' after ''20590–001'';

■ b. In the table in paragraph (c) items B.(18) and B.(19) are added to read as follows:

§ 195.3 Incorporation by reference.

* * * * *

(c) * * *

Source and name of referenced material	49 CFR reference
* * * * * * *	
B. * * *	
(18) API Recommended Practice 1165 "Recommended Practice for Pipeline SCADA Displays," (API RP 1165) First Edition (January 2007).	§ 195.446(c)(1).
(19) API Recommended Practice 1168 "Pipeline Control Room Management," (API RP 1168) First Edition (September 2008).	§ 195.446(c)(5).
* * * * * * *	

■ 10. In § 195.402, paragraph (c)(15) and (e)(10) are added to read as follows:

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(15) Implementing the applicable control room management procedures required by § 195.446.

* * * * *

(e) * * *

(10) Actions required to be taken by a controller during an emergency, in accordance with § 195.446.

* * * * *

■ 11. Section 195.446 is added to read as follows:

§ 195.446 Control room management.

(a) *General.* This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. The procedures required by this section must be integrated, as appropriate, with the operator's written procedures required by § 195.402. An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2012.

(b) *Roles and responsibilities.* Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.

(c) *Provide adequate information.* Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement API RP 1165 (incorporated by reference, *see* § 195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Implement section 5 of API RP 1168 (incorporated by reference, *see* § 195.3) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation.* Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not exceeding 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management.* Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Implement section 7 of API RP 1168 (incorporated by reference, see § 195.3) for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; and

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations.

(g) *Operating experience.* Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review accidents that must be reported pursuant to § 195.50 and 195.52 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) *Compliance validation.* Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviations.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of the pipeline facility.

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Cynthia L. Quarterman,

Administrator.

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