INGAA

November 12, 2008

DOT Docket Management System: U.S. Department of Transportation
Docket Operations, M-30
West Building Ground Floor
Room W12-140
1200 New Jersey Avenue, S.E.
Washington, DC 20590-0001

VIA E-GOV WEB SITE

Re: Docket No. PHMSA-2007-27954: *Pipeline Safety: Control Room Management/Human Factors*

Good afternoon:

Pursuant to the notice of proposed rulemaking ("NOPR") issued in the referenced docket by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") on September 2, 2008, and published in the September 12, 2008, issue of the *Federal Register*,[1] the Interstate Natural Gas Association of America ("INGAA") submits the following comments:

INGAA is a non-profit trade association that represents the interstate natural gas transmission pipeline industry. INGAA's members operate over two thirds[2] of the nation's natural gas transmission pipeline mileage, and represent almost one quarter of the individual natural gas transmission pipeline entities reporting to PHMSA. Their interest in the NOPR is self-evident.

Moreover, INGAA and its members have displayed a consistent commitment to pipeline safety, including the development of a control room management rule. They have expressed their commitment not only through their statements and filings in numerous PHMSA dockets, but also by welcoming PHMSA into members' control rooms, by preparing comments and presentations at the two control room management public workshops, and by working with PHMSA's Controller Certification Project ("CCERT") staff for over six years as they collected data and examined existing practices.

As detailed in the general comments, INGAA strongly opposes the proposed regulations. INGAA urges PHMSA to adopt an alternative set of control room regulations, which several trade associations[3] filed in this docket on November 12, 2008, as INGAA believes the Joint Associations' substitute rule addresses public safety concerns and conforms to Congressional direction.

This letter concludes with specific comments expressing particular concern with several individual aspects of the NOPR. The specific comments are not intended to suggest, and should not be read to suggest, tacit agreement with or acceptance of the remainder of the NOPR or any of its components.

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1 73 Fed. Reg. 53075.

2 INGAA members operate 223,000 miles of the 319,000 miles of natural gas transmission pipelines and 349 of the 1417 natural gas transmission operators reporting to PHMSA in 2007.

3 American Gas Association ("AGA"), American Public Gas Association ("APGA"), American Petroleum Institute ("API"), American Oil Pipeline Association ("AOPL") and INGAA (collectively "the Joint Associations").

GENERAL COMMENTS

I. THE PROPOSED REGULATIONS ARE FUNDAMENTALLY FLAWED AND SHOULD BE REJECTED IN THEIR ENTIRETY.

A. 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.

PHMSA's authority to issue the proposed regulations rests on the 49 U.S.C. § 60137, which was created by Section 12 of the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (the "PIPES Act").[4] In pertinent part, these sections state:

> (a) Not later than June 1, 2008, the Secretary shall issue regulations requiring each operator of a gas or hazardous liquid pipeline to develop, implement, and submit to the Secretary . . . a human factors management plan designed to reduce risks associated with human factors, including fatigue, in each control center for the pipeline. Each plan must include, among the measures to reduce such risks, a maximum limit on the hours of service established by the operator for individuals employed as controllers in a control center for the pipeline.
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> (e) In issuing regulations under subsection (a), the Secretary shall develop and include in such regulations requirements for an operator of a gas or hazardous liquid pipeline to report deviations from compliance with the plan submitted by the operator under subsection (a).

The only regulations mandated by PIPES Act Section 12 are procedural. They are to direct each pipeline operator to develop, implement and submit a human factors management plan; and they are to require operators to report deviations from the plans as filed. As discussed below, the proposed regulations reach substantive areas, facilities and personnel far outside the PHMSA's limited statutory mandate.

1. The proposed regulations address substantive areas outside Section 12.

Section 12 authorized modest procedural regulations. It did not authorize, and Congress did not intend it to authorize, PHMSA to establish substantive regulations: (1) requiring the integration of human factors management plans with other manuals or procedures;[5] (2) establishing controller roles and responsibilities;[6] (3) specifying standards for the communication, presentation, exchange and verification of data and other information provided to controllers;[7] (4) specifying standards for alarm management;[8]

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4 Pub.L.No. 109-468 (109th Cong.) (2006). The NOPR preamble implies a broader authority looking to the regulation of human factors as a logical extension of PHMSA's regulation of facilities and procedures, NOPR, 73 Fed. Reg. at 53076 ("The next logical area of program development is to examine the role people play in operating and maintaining pipelines."). INGAA appreciates the mandate of Section 12 and the corresponding statutory deadline for issuing regulations. That said, there is little to no data supporting the conclusion that, with regard to natural gas transmission pipeline control room management, the suggested examination and resulting regulations are "the next logical area of program development." For this reason among others, INGAA confines its remarks to whether the proposed regulations are consistent with the congressional direction behind Section 12.

5 Proposed 49 C.F.R. § 192.631(a).

6 Proposed 49 C.F.R. § 192.631(b).

7 Proposed 49 C.F.R. § 192.631(c).

(5) imposing specific procedures for operators to follow when planning and implementing modifying their systems, performing maintenance, or undergoing a merger;[9] (6) prescribing how operators will review not only reported incidents, but also "close-call" events not significant enough to require reporting;[10] (7) defining how controllers must be trained and how often they have to undergo training;[11] and, (8) mandating yearly senior executive confirmation that all of these standards have been met.[12]

Proposed 49 C.F.R. §§ 192.631(a), (b), (c), (e), (f), (g), (h) and (j) exceed the scope of regulation Congress intended when it enacted Sections 12(a) and (e) of the PIPES Act. Accordingly, all of these proposed sections should be significantly edited or deleted.

Section 12 mentions only one substantive area of control room management: fatigue. More specifically, Section (a) provides:

> Each plan must include, among the measures to reduce [risks associated with human factors], a maximum limit on the hours of service established by the operator for individuals employed as controllers in a control center for the pipeline.[13]

In fact, Section 12(b) of the PIPES Act prohibits the Secretary of Transportation and state pipeline safety officers from accepting a human factors management plan that does not include a limit on hours of service.[14] It can therefore be argued that Proposed 49 C.F.R. § 192.631(d), addressing fatigue mitigation, has a least some statutory foundation. The Joint Associations' substitute rule addresses fatigue, and INGAA urges adoption of these provisions along with the rest of the substitute rule.

Procedures for submitting plans and reporting deviations, the only subjects addressed in Section 12, are reflected in just two provisions of proposed 49 C.F.R. § 192.631: the first sentence of proposed 49 C.F.R. § 192.631(a), and proposed 49 C.F.R. § 192.631(k), which deals with deviations. Even here one of the proposals raises serious concerns.

Under the first sentence of proposed 49 C.F.R. § 192.631(a), "Each operator of a pipeline facility with at least one controller and control room must have and follow written control room management procedures that implement the requirements of this section." The proposed regulation substitutes its own term, "control room management procedures that implement the requirements of this section" for the statutory term, "human factors management plan." Also, the proposed regulation does not direct that the plans be submitted, as required under PIPES Act Section 12(a), but instead requires that the management procedures be incorporated "into the operator's written manual on operations and maintenance, . . . written qualification program . . . and written emergency plans."[15] These departures from the plain language of Section 12 are justified by PHMSA's belief that "this makes it more likely that the actions required in this proposed rule will be integrated effectively into pipeline operations, thus

8 Proposed 49 C.F.R. § 192.631(e).

9 Proposed 49 C.F.R. § 192.631(f).

10 Proposed 49 C.F.R. § 192.631(g).

11 Proposed 49 C.F.R. § 192.631(h).

12 Proposed 49 C.F.R. § 192.631(j).

13 49 U.S.C. § 60137(a).

14 Id., § 60137(b).

15 Proposed 49 C.F.R. § 192.631(a).

limiting the potential for miscommunications to occur."[16] Such hypothetical benefits, unsupported in the record, hardly provide grounds for blurring statutory limits on the areas to be regulated.

The substantive provisions of human factors management plans are properly established not by imposing regulations, but by continuing the ongoing (and PHMSA supported)[17] process of constructively sharing practices within the industry. One notable product of this consensus process is API's Recommended Practice 1168, *Pipeline Control Room Management* ("RP 1168"). PHMSA supported and participated in the development of RP 1168; in fact, the NOPR provides, "Once these materials are completed, PHMSA will review them and consider a regulatory amendment to incorporate by reference all or parts of such applicable documents in amended regulations." RP 1168 was published after the NOPR was issued, but now that RP 1168 has been published it should be appropriately reflected in whatever regulations emerge from this docket.

The Joint Associations' substitute rule is built upon RP 1168, and it should be promulgated in lieu of the current proposal.

2. The proposed regulations address facilities and personnel outside Section 12.

Section 12(a) specifies that the required human factors management plan is to be designed "to reduce risks associated with human factors, including fatigue, *at each control center* for the pipeline."[18] The NOPR references "control room" instead of "control center," which is reasonable since the heading for Section 12 is "Pipeline Control Room Management."

While the PIPES Act does not define what is meant by "each control center," over the years the scope of the control room management rule has been the subject of extensive discussions, culminating in the control room management public workshop held May 23, 2007.[19] During that workshop all of the stakeholders in attendance — PHMSA, industry, members of the public, the National Transportation Safety Board ("NTSB") and others — reached agreement on a scope for the propose rule that would be effective, logical and consistent with what Congress intended when it enacted Section 12 of the PIPES Act. The agreed upon definition appears in the NOPR preamble:

> Most operators monitor pumps, compressors, valves and other equipment from single or multiple locations, often hundreds of miles away. Such locations are commonly known as "control rooms." The individuals who work in control rooms are "controllers."
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> The control room is the central location where humans or computers receive data from field sensors.

Without any meaningful explanation or citation to the record, the proposed regulations ignore the workshop consensus and define "control room" to include any "local station" where a control panel,

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16 NOPR, 73 Fed. Reg. at 53086. It is far from clear how such integration is to occur, and the proposed regulations offer no guidance. The lack of clarity and resulting unwarranted imposition of regulatory risk give further reason for rejecting proposed 49 C.F.R. § 192.631(a).

17 NOPR, 73 Fed. Reg. at 53084.

18 49 U.S.C. § 60137(a) (emphasis added).

19 See generally NOPR, 73 Fed. Reg. at 53080-81.

computerized device or other instrument is used to monitor or control all or part of a pipeline or pipeline facility.[20] Based on this definition, thousands of field locations would be considered "control rooms."

None of the workshop participants advocated such sweeping scope for these regulations, nor has it been established that regulating beyond the central location is cost justified or results in increased pipeline safety.

The breadth of these proposed regulations is compounded by its equally expansive definition of "controller." Under the proposed definition, anyone who periodically checks system pressures, cathodic protection systems, or volumetric flow rates at either an operations center, remote field location, or remotely via computer connection would be a controller, even those persons who only monitor part of a system occasionally and have no ability to affect safety-related conditions on the pipeline, *e.g.*, corrosion control personnel, measurement personnel, and personnel required to operate and monitor pipelines' electronic bulletin boards per regulations issued by the Federal Energy Regulatory Commission. Thousands of natural gas transmission pipeline employees would become subject to these regulations,[21] at considerable cost, with no discernable improvement in pipeline safety. There is no indication in the record that Congress intended such a broad definition of "controller" when it enacted Section 12.

Separately, the proposed regulations impose requirements on natural gas transmission pipelines and LNG facilities that Congress specifically intended for liquid pipelines only. In Section 19 of the PIPES Act, Congress directed the Secretary of Transportation to issue standards implementing three recommendations from a 2005 NTSB study investigating accidents on hazardous liquid pipelines.[22] The NTSB report concerned hazardous liquid pipelines, and only hazardous liquid pipelines,[23] and the statutory authority conferred by Section 19 was expressly limited to hazardous liquid pipelines; nevertheless, the proposed regulations would impose the NTSB recommendations not only to hazardous liquid pipelines, but on natural gas transmission pipelines and LNG facilities as well.

The NOPR does not acknowledge that Section 19 limited PHMSA's authority to impose SCADA regulations. In fact, the NOPR does not acknowledge Section 19 at all.[24] According to the NOPR, comprehensive regulations for natural gas transmission pipeline and LNG SCADA systems are justified because "PHMSA considers that the NTSB recommendations apply equally to gas and hazardous liquid pipelines and to LNG facilities." No record evidence is cited to support PHMSA's conclusion.

In defining control room to include local stations, in imposing these regulations on LNG facilities, and in imposing the SCADA requirements on natural gas transmission pipelines and LNG facilities, the proposed rule repeatedly countermands express provisions of the PIPES Act, including

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[20] As proposed, these regulations would even apply to liquefied natural gas ("LNG") facilities, which are designed to retain unintentional releases within a pre-defined footprint.

[21] This estimate does not include the anticipated additional thousands of employees in the other pipeline industries.

[22] *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines*, Safety Study NTSB/SS-05-02 (NTSB: adopted Nov. 29, 2005). PHMSA cites this study in the NOPR, 73 Fed. Reg. at 53083, n. 5.

[23] NTSB presented this study at two public meetings, and never stated or implied that its findings should be applied to natural gas transmission pipelines. Not surprisingly, the recommendations emerging from that study were directed at hazardous liquid pipelines.

[24] The NOPR cites the three recommendations appearing in Section 19, but does not cite the statute itself. NOPR, 73 Fed. Reg. at 53083

express limits on the authority to regulate. Each of these aspects of the NOPR should therefore be stricken in its entirety.

B. The proposed regulations are not justified on a cost-benefit basis.

It is self-evident that for a set of proposed regulations to be cost justified there need to be a measurable benefit. In this case, no measurable benefit has been identified. The sole foundation for these regulations is the same NTSB study cited in Section 19 of the PIPES Act. As to natural gas transmission pipelines and LNG facilities, the foundation is not the body of the study but an appendix describing six events which, according to PHMSA, "can help illustrate the importance of control rooms and controllers to safe pipeline operation."[25]

An examination of the appendix reveals that of the six described events only three involved natural gas transmission pipelines and none involved liquefied natural gas ("LNG") facilities. Moreover, none of these events were investigated by NTSB or PHMSA, and none of them rose to the level of a reportable incident. This should not be surprising, as the study was focused on hazardous liquid pipelines and the recommendations emerging from that study were directed at hazardous liquid pipelines. NTSB presented this study at two public meetings, and never stated or implied that its findings should be applied to natural gas transmission pipelines.

In contrast, INGAA and its members have provided PHMSA overwhelming evidence, through multiple surveys and through discussions with numerous member operators, that controllers can not and do not cause pipeline incidents. The NOPR does not engage the substance of any of this material. Instead, PHMSA simply says it disagrees based on a small set of controller responses to questions that asked, in essence, whether a controller caused pipeline incident was at least theoretically possible. Candidly acknowledging **theoretical** possibilities do not change the facts, and the facts are that for natural gas transmission pipelines[26] and LNG facilities[27] there has not been one case where primary cause of an incident has been attributed to controller error.

In the absence of record evidence the NOPR bases its cost-benefit analysis on assumptions, speculation and generalities. In estimating the benefits of the proposed rule, Econometrica Analysis states: "As cited earlier, different sources report that controllers are said to be responsible for only about 3 to 7 percent of incidents. For analytic purposes, we will assume 5 percent."[28] The 3 to 7 percent refers to **liquids** pipelines.[29] There is no cited basis in the Econometrica Analysis or the NOPR to assume controller responsibility for any natural gas or LNG accidents.[30] If there are already no accidents for

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25 NOPR, 73 Fed. Reg. at 53078.

26 The Regulatory Flexibility Analysis for the proposed rule acknowledges as much: "A gas pipeline industry analysis showed that during a 10-year period (from 1995 through 2004), gas pipeline controllers had not caused **any** failures of gas pipeline facilities." Preliminary Regulatory Analyses: Control Room Management/ Human Factors Notice of Public Rulemaking (Econometrica, Inc. Jun. 23, 2008) ("Econometrica Analysis"), p.15 (emphasis supplied), *citing* White Paper on Gas Pipeline Risk Analysis, INGAA Pipeline Safety Committee and AGA Gas Control Committee (Feb. 2006). "

27 "There have been very few incidents related to LNG facilities in the United States, none caused by controller error." Econometrica Analysis, p. 16.

28 Econometrica Analysis, p. 41

29 Id., p. 15.

30 During a discussion of liquids pipelines the Econometrica Analysis cryptically observes, "Later data (from 2002) show that operation (of which controllers are a subset) caused about 5 percent of the accidents in the

which natural gas or LNG controllers are responsible, the projected benefit of the proposed regulations for these entities is zero.

Similarly, PHMSA presumes without foundation that 10 percent of all deaths, injuries, and property loss would be eliminated by quicker and better controller response to an incident.[31] This figure is not supported by any analysis whatsoever. Moreover, this arm of the cost-benefit analysis underscores how small the potential benefits of these proposed rule really are. As a point of reference, we reviewed the PHMSA incident statistics for the previous 5 years to determine how many fatalities and injuries were caused by incorrect operations on natural gas transmission pipelines. There were no fatalities, five injuries (company employees and contractors), and a total of $1,865,000 in damage. Utilizing PHMSA's cost figure of $238,000 per injury from section 2.6.2.1, this yields a potential benefit pool for Gas Transmission Pipelines of only $3,055,900 for 5 years or $611,180 per year.

The benefits of this proposed rule for the natural gas transmission companies are *de minimis* compared to the expected annual costs for the next 10 years of nearly $140,000,000. A handful of anecdotes 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 natural gas transmission pipeline industry.

C. As the annual cost of the proposed rule would exceed $100 million, Executive Order 12866 requires that these regulations undergo review by the Office of Management and Budget ("OMB").

According to the NOPR, OMB review is not necessary because "The monetary costs of the rule are expected to average about $25 million per year."[32] Several of INGAA's members performed a detailed study of the expected costs of the proposed regulations on the member's pipeline. These results were then extrapolated for INGAA's membership, which represents slightly over two thirds of the nation's natural gas transmission pipeline mileage,[33] and approximately 40 separately operated natural gas transmission pipelines.

The results are provided below:

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liquid sector and 3 percent in the gas pipeline sector. Id. That sentence cites to a web page containing incident statistics. Id., n. 45. However, the cited statistics provide no basis for assuming that gas or LNG controllers have been responsible for any incidents on their systems.

31 Econometrica Analysis, p. 41

32 NOPR, 73 Fed. Reg. at 53093.

33 See n. 2, *supra*.

Estimated Implementation Costs for Selected Proposed Regulations			
Proposed Regulation	Subject	Initial Cost	Annual Cost
192.631(c)(2)(i)	Point-by-Point Baseline Verification	$126,000,000	
192.631(d)(2)	Controller Education: Fatigue	$250,000	$25,000
192.631(e)(1)	Weekly SCADA Review		$32,000,000
192.631(e)(1)(i)	Non-Alarmed Event Investigation		$10,000,000
192.631(e)(1)(ii)	Review of Alarm Response		$2,015,000
192.631(e)(1)(iii)	Assessing Changes in Alarm Rate		$1,540,000
192.631(e)(1)(iv)	Assessing Unexplained Alarms		$1,946,000
192.631(e)(1)(v)	Verification Against Excessive Alarms		$24,000,000
192.631(e)(1)(vi)	Assessing Acknowledged Alarms		$2,000,000
192.631(e)(1)(vii)	Review of Operator Response to AOC		$24,000
192.631(e)(1)(viii)	Identification of Maintenance Issues		$10,000,000
192.631(e)(1)(xi)	Comparing Logs vs. Alarm Records		$6,400,000
192.631(e)(2)(i)	Alarm Evaluation		$8,000,000
192.631(e)(2)(iii)	Investigating Unnecessary Alarms		$13,000,000
192.631(e)(2)(viii)	Evaluation of Controller Workload		$484,000
192.631(e)(2)(x)	Verification of Alarm Set Points		$4,234,000
192.631(g)(1)	Review of Control Room Operations		$80,000
192.631(h)(4)	Controller Field Visits		$450,000
192.631(h)(5)	Review of Infrequent Procedures	$800,000	$1,400,000
192.631(h)(6)	Hydraulic Pipeline Training	$11,450,000	$19,200,000
192.631(h)(7)	Training re Failure Modes	$124,486,000	
192.631(*i*)(8)	Mandatory Controller Qualification		$3,000,000
Total		**$262,986,000**	**$139,798,000**

II. THE PROPOSED REGULATIONS SHOULD BE WITHDRAWN AND THE PROPOSED CONTROL ROOM REGULATIONS SUBMITTED BY THE JOINT ASSOCIATIONS SHOULD BE PROMULGATED IN THEIR PLACE.

On October 8, 2008, the Joint Associations filed a letter in this docket[34] expressing serious concerns about the proposed rule. They wrote that the proposed rule is inconsistent with the congressional direction, inconsistent with NTSB safety recommendations, and in violation of Executive Orders. In addition, the scope and definitions at the heart of the proposed rule are technically flawed. In short, the administrative deficiencies and conceptual problems with the proposed rule are so fundamental that they can not be addressed through amendments and must therefore be addressed by adopting entirely new language. The Joint Associations suggested PHMSA withdraw the proposed rule and issue an amended notice with proposed regulations that have a scope and definitions that reflect Congressional

[34] The letter is designated as document PHMSA 2007-27954-0032.1.

direction, and incorporate both the input received at the public meetings and consensus standards that have been developed to date.

The Joint Associations continue to believe the proposed rule needs to be withdrawn and a new set of proposed rules needs to be issued. Concurrent with this filing, the Joint Associations are submitting a letter proposing alternative control room management regulations for natural gas and hazardous liquid pipelines.[35] The Joint Associations, including INGAA, urge PHMSA to promulgate the Joint Associations' substitute rule in lieu of the regulations appearing in the NOPR.

The substitute rule is simple and straightforward, because simplicity and straightforwardness are necessary to account for the diversity of control room structures. The substitute rule follows the mandates of Congress and adds only what is necessary for all control room operations. Moreover, because of its more focused scope, the substitute rule would not require Office of Management and Budget review because its costs would not exceed $100 million annually.

In addition to withdrawing the current rule and promulgating the Joint Associations' substitute, INGAA separately urges PHMSA to give the Pipeline Safety Advisory Committees the opportunity to vote on the suggested alternative language sections during their December meetings. The substitute rule and cover letter are provided to support withdrawal and reissuance by PHMSA, or to allow the Pipeline Safety Advisory Committees to vote upon the substitute rule as a whole rather than attempting to craft amendments to a complex and confusing proposed rule.

SPECIFIC COMMENTS

The following comments address both the preamble and the actual proposed rule language. INGAA **recommends most of this proposed language being removed or extensively edited prior to becoming a final rule**, but feels compelled to make these comments to ensure the technical issues are fully vetted and understood.

I. Preamble Section I: Prevention Through People ("PTP")

A. Integrating of PTP into Integrity Management ("IM") Plans

PHMSA states, "Explicitly incorporating a PTP element in IM plans would emphasize the role of people both in contributing to and in reducing, risks."[36] INGAA responds that it is unclear why PTP is being applied to natural gas transmission pipeline control rooms if PHMSA states the best place is in the existing integrity management rules. It would seem logical that if one believes a location is the best place for some action, the action should take place in that location.

B. Developing PTP Measures through Best Practices Instead of Regulations

PHMSA states, "In addition to regulations, PHMSA plans to identify and promote noteworthy best practices in PTP."[37] The better course is to begin with best practices and learn from their implementation and effectiveness rather than begin with difficult-to-modify regulations and then build the best practices. Additionally, PHMSA has historically shied away from best practices in regulatory

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35 Alternative language is not provided for LNG control room management because LNG processing should be separated from this proposed rule, which is directed at transportation pipelines.

36 NOPR, 73 Fed. Reg. at 53076.

37 NOPR, 73 Fed. Reg. at 53076.

activity as witnessed in the Operator Qualification deliberations in 2003, where PHMSA agreed that of the 13 Issues industry jointly agreed to address, only one, Noteworthy Practices, would not be specifically addressed in a national consensus standard or subsequent rule. PHMSA agreed Noteworthy Practices would be best addressed in industry workshops and the regional trade associations.

II. Preamble Section II: Background

A. Confusion of "Operator" and "Owner"

PHMSA states, "Throughout this document, the term "operator" refers to both owners and operators of pipeline facilities."[38] This is inappropriate. Under the federal pipeline safety regulations, an "operator means a person who engages in the transportation of gas."[39] Commonly defined, a person would clearly include an entity in this case, but it still references "engages" which implies operates. Nowhere do PHMSA's own regulations reference the owners of pipeline facilities. Additionally, PHMSA extensively uses operator identification numbers, which implies they are interested in the operators of facilities, not the owners. Further, PHMSA does not send enforcement actions or technical inquiries to pipeline facility owners, but instead to the pipeline facility operators.

B. Role of American Society of Mechanical Engineers ("ASME") Standard B31Q

PHMSA states, "Existing operator qualification ("OQ") regulations for pipeline personnel currently address a portion of the processes affecting a controller's ability to succeed in maintaining pipeline safety and integrity." While the existing OQ rule may only address a portion of what PHMSA desires, the OQ rule was considered for modification in 2003 and no changes other than a requirement for training was made. Further, INGAA actively participated in the development of ASME's B31Q Pipeline Personnel Qualification standard, an ANSI approved consensus standard, which states that a task must have pipeline safety and integrity components to become a task, much like what PHMSA desires. The ASME B31Q Committee then took this definition and engaged a large group of subject matter experts to consider controllers activities as they related to pipeline safety and integrity. This expert group made a series of conclusions, which are embodied in ASME's B31Q. After promoting the development of ASME B31Q, PHMSA has unfortunately chosen to ignore it in the pipeline safety regulations. INGAA believes using ASME B31Q's task list, particularly as it relates to controller tasks, would alleviate PHMSA's concern. Finally, ASME B31Q's task list is largely adopted by natural gas transmission pipeline operators, without any regulatory intervention.

C. Development of Database for Low-Level Events

PHMSA states, "Controller vigilance and appropriate response to lower-level events thus serves to prevent reportable pipeline incidents from occurring."[40] INGAA responds that there has not been one case where primary cause of an incident has been attributed to controller error. It can therefore be concluded that there is no positive cost-benefit ratio for natural gas transmission pipeline operators provided by this proposed rule, since there are no measurable benefits. Further, and we will comment on this again later, PHMSA's desire for industry to individually create low-level near-miss criteria, when PHMSA has been unable to do so for a period of years, is unreasonable. Consistent, measurable data should be the hallmark of good rule development, and PHMSA has not proposed, let alone established, any criteria to standards for measurement or protocols to ensure data consistency.

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[38] NOPR, 73 Fed. Reg. at 53077.

[39] 49 C.F.R. § 192.3.

[40] NOPR, 73 Fed. Reg. at 53080.

D. Inter-Company Review

PHMSA states, "PHMSA encourages these industries to consider establishing such processes and invites the public and industry to comment on the value of such an inter-company review process."[41] INGAA desires this as well, and in fact supports and facilitates repeated inter-company meetings, and supports regional trade associations to do the same. INGAA encourages PHMSA to host public meetings where applicable data can be shared and placed on the public record to ensure that transparency exists and all the data can be used by all operators and reviewed by the public.

III. Preamble Section III: Human Factors Studies

A. Uniform Controller Certification

PHMSA states, "The CCERT team concluded that a single controller certification process for the entire pipeline industry would not be appropriate for a number of reasons."[42] INGAA agrees. In a previous docket,[43] INGAA commented that a certification process for controllers was unnecessary, would be overly costly, would provide at best limited benefits, and would be difficult to implement. The withdrawal of CCERT's proposed mandatory certification process was one of the few areas that INGAA's docket comments were heeded.

B. References to Other Industries' Validation and Certification Programs for Control Room Personnel

PHMSA states, "Other industries, which employ validation and certification programs for control room personnel, also provided lessons learned in the development, implementation, and maintenance of validation and certification programs."[44] INGAA asks which industries are being referenced, and whether they have the same type of control scenario. In many of the industries that PHMSA has studied, the controllers have the ability to cause an incident, *e.g.*, airlines, railroad, trucking and nuclear power. These differences compel the managing of the natural gas transmission pipeline industry in a different fashion from these "other industries." INGAA's recommendation is to follow Congress's lead and limit the scope to their direction.

C. Mischaracterization of June 27, 2006 Workshop

PHMSA states, "Discussions in the first public workshop held June 27, 2006, reflected general acknowledgement by the pipeline industry that the process outlined above was appropriate to reduce control room risk."[45] INGAA states that, following review of the transcripts of the two public meetings, the scope of the proposed rule was never contemplated at either meeting. In fact, at the conclusion of the second public meeting a member of the public took a public microphone and summarized the presentations and findings with a "scope" as it was implicitly understood it at that time. The proposed rule's scope is widely divergent from that "scope". To say there was "general acknowledgement by the pipeline industry" is incorrect.

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41 NOPR, 73 Fed. Reg. at 53080.

42 NOPR, 73 Fed. Reg. at 53081.

43 PHMSA Docket PHMSA-RSPA-2004-18584.

44 NOPR, 73 Fed. Reg. at 53082.

45 NOPR, 73 Fed. Reg. at 53083.

Curiously the very next sentence in the NOPR states, "At the same time, most agreed that there was no need for major changes to current control room practices and staffing."[46] INGAA finds it interesting that PHMSA acknowledges no need for major changes. However, the proposed rule as written, and as discussed in detail in following sections of these comments, would approximately triple the number of controllers[47] (not including support of SCADA staff) needed to complete the necessary paperwork, recordkeeping, and increased non-safety-related activities necessary to comply. Further, the proposed rule should be classified as "significant" and thus subject to more Office of Management and Budget scrutiny. Each of these examples would indicate that PHMSA's statement is untrue and in fact would necessitate major changes to current control room practices and staffing.

D. CCERT Findings Regarding the Use of Color in SCADA Displays

PHMSA states, "They [the CCERT team] also found very few operators who consider the impact of color perception . . . ."[48] This concern is misplaced. First, the issue has been examined by the ASME B31Q Committee. The Committee concluded that controllers should be able to differentiate meaningful colors on screens, or have a viable method of making the same differentiation as it relates to pipeline safety using another method. This is done in control rooms now. Controllers have been qualified under ASME B31Q requirements, and no incidents have ever been attributed to this issue. Second, for most pipelines the use of color is augmented by the use for sounds, flashing lights and stimuli. Finally, the concern about color perception fails to take into account the costs (and transitional confusion) many pipelines would experience if they had to convert their existing systems of color coded alarms to a one-size-fits-all regulatory requirement.

E. Point-to-Point Re-Verification

PHMSA states, "They [the CCERT team] also found *very few* operators who…perform periodic point-to-point verifications of screen display data with field instrumentation."[49] Operators conduct point-to-point verifications during installation of various SCADA systems, but to our knowledge, **no** operators in the pipeline industry perform full point-to-point re-verifications of screen display data. INGAA questions also how many operators PHMSA interviewed to collect their data and form their conclusions on whether that data set is statistically significant given the hundreds of pipeline operators. INGAA will, later in these comments, address the extraordinary costs of performing mandatory point-to-point re-verifications and the attendant lack of benefits.

F. Alarms

The NOPR devotes a full paragraph recounting CCERT findings that many alarms and other information received by controllers is not being used.[50] INGAA responds that while many of the concepts discussed in this paragraph may have merit, these do not focus on the primary pipeline safety alarms.[51] Furthermore the discussion ignores the redundant local overpressure protections systems and

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[46] NOPR, 73 Fed. Reg. at 53083.

[47] INGAA Member Phone Survey.

[48] NOPR, 73 Fed. Reg. at 53083.

[49] NOPR, 73 Fed. Reg. at 53083 (emphasis supplied).

[50] NOPR, 73 Fed. Reg. at 53083.

[51] For example, the paragraph does not mention that on some pipeline systems there are some alarms that are used for tariff purposes, and other reasons that do not necessarily impact pipeline safety.

relief valves that prevent overpressure of natural gas transmission pipelines. Further, this list most resembles a list of best practices, and is not reasonably translatable to regulatory requirements. There is also no linkage from the ideas embedded in the paragraph to any incident or even near-miss data. In short, INGAA believes this paragraph should be considered as a best practice list for consideration at a future date.

G. Simulators

PHMSA states, "The controllers interviewed generally found full simulators to have significant value."[52] INGAA responds that the CCERT team interviewed a very small subset of the operating community and that it is highly unlikely this subset would consist of a statistically significant number of operators. In fact, to further question CCERT's findings, INGAA's larger members use almost no full simulators for controller training because their systems are so expansive and unique that full simulators do not exist. As a matter of record, INGAA members do use partial simulators and table-top exercises to accomplish the same function as full simulators. In short, the simulator issue is really one of training, and operators should remain able to select among a variety of appropriate training methods.

H. Human Factors Coordinating Committee ("HFCC")

PHMSA states that it "has drawn from the work of the HFCC to help identify fatigue management strategies for control room management."[53] INGAA supports PHMSA utilizing and consulting the HFCC, and notes that the scope appears to be limited to helping "identify fatigue management strategies." This scope is very similar to part of the scope Congress directed PHMSA to use in any control room management rule, and should be encouraged.

IV. Preamble Section V: Standards, Recommended Practices, and Guidelines

A. API 1168

The NOPR acknowledges API's recommended practice on control room management, noting that "Specific guidance anticipated in this recommended practice will address: (1) Roles and Responsibilities, (2) Shift Operations, (3) Management of Change, and (4) Fatigue."[54] INGAA agrees with this guidance, and is actively engaged in its development. However, it should remain guidance and not rule, in light of the direction provided by Congress and the lack of a cost-benefit analysis.

V. Preamble Section VI: PHMSA's Proposed Approach

A. Integration of Control Room Management Plan with Other Practice and Procedure Documents

Under the proposed regulations operators would be required to incorporate appropriate control room management elements into the operator plans and procedures which are already required under existing regulations. In PHMSA's view, integration will minimize operator burden and "also avoid operators having another plan that may create or exacerbate internal communication complexities."[55] INGAA responds that it is interesting that PHMSA believes this proposed structure will "avoid operators

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[52] NOPR, 73 Fed. Reg. at 53083.

[53] NOPR, 73 Fed. Reg. at 53084.

[54] NOPR, 73 Fed. Reg. at 53084.

[55] NOPR, 73 Fed. Reg. at 53084.

having another plan."[56] This is not possible, since Section 12(b) of the PIPES ACT specifically PHMSA to review and approve the plans. Are operators to submit all the various plans that will be integrated into control room management to PHMSA for approval or do they intend to review and approve the plans during standard inspections? Many operators use different plans to meet their respective technical competencies. Many of these plans are already under the auspices of the federally required operating and maintenance plans. Requiring a fully integrated control room management plan integrated into many manuals adds yet another layer of increased burden on the controllers themselves. Further, PHMSA dictating the number of manuals gets very close to a "prescriptive" requirement, which is what PHMSA claims is not included in the proposed rule.

B. Performance-Based vs. Command-and-Control Regulation

PHMSA states, "The control room management elements describe 'what' an operator must include but not 'how' an operator must carry out such elements."[57] INGAA disagrees. For example, proposed 49 C.F.R. § 192.631(c)(3) requires "verbal communication" to the exclusion of electronic mail, phone texting or other communication alternatives Further, this rule fails the performance language criteria PHMSA claims when, in proposed 49 C.F.R. § 192.631(h), PHMSA requires a one year interval for re-examining the training plan. In true performance language, this interval would be determined by the operator using accepted methods. In reviewing the preamble to the proposed rule, there is no discussion or technical justification for the one-year requirement, just an edict that it shall be followed in a very prescriptive language format.

VI. Proposed Regulatory Text

The following comments apply directly to the proposed rule language, and are limited to the proposed Part 192 language. In many instances, INGAA's comments can be summarized by stating that we believe the final rule language should be what Congress intended and add public safety value, and should embody only those sections and concepts contained in the Joint Association Filing. However, we also believe that we should comment on specific individual sections of the proposed rule, and provide an outline of the expected costs INGAA member companies will incur if this rule were promulgated as proposed. The presentation of comments on specific proposed provisions should not be interpreted as agreeing with or acceding to any other provision of the proposed rule.

For ease of reference, the text of the proposed rule will be provided immediately before the corresponding comments.

A. Proposed Amendments to 49 C.F.R. § 192.3 (Definitions)

1. "Alarm"

> *Alarm means an indication provided by SCADA or similar monitoring system that a parameter is outside normal or expected operating conditions.*

This definition ties primarily to section (e) in the proposed rule, which is not required or even contemplated by Congress for natural gas transmission pipelines, and therefore should be deleted.

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[56] NOPR, 73 Fed. Reg. at 53084.

[57] NOPR, 73 Fed. Reg. at 53085.

2. "Control Room"

Control room means a central location or local station at which a control panel, computerized device, or other instrument is used by a controller to monitor or control all or part of a pipeline facility or a component of a pipeline facility.

In General Comment I.A.2. above, INGAA details how the current definition runs counter to congressional direction, particularly as to the inclusion of local stations. INGAA recommends adoption of the definition appearing in the Joint Associations' substitute rule, which basically incorporates the definition found in API RP 1168.

3. "Controller"

Controller means an individual who uses a control panel, computerized device, or other equipment to monitor or control all or part of a pipeline facility that the individual cannot directly observe with the naked eye. An individual who operates equipment locally, but who cannot see the equipment respond without using a closed circuit television system or other external device, is a controller when performing this activity regardless of job title or whether actions are overseen by another controller or supervisor. An individual who performs these functions on a part time basis is considered a controller only when performing these functions.

In General Comment I.A.2. above, INGAA details how the current definition runs counter to congressional direction, particularly as to the inclusion of local stations. INGAA recommends adoption of the definition appearing in the Joint Associations' substitute rule, which basically incorporates the definition found in API RP 1168.

4. "Supervisory Control and Data Acquisition System (SCADA)"

Supervisory Control and Data Acquisition System (SCADA) means 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.

As explained in General Comment I.A.2. above, imposing the proposed SCADA regulations on INGAA's exceeds the regulatory authority granted under Section 19 of the PIPES Act. In addition, the proposed definition is overly broad and does not apply to the way natural gas transmission pipelines operate or the way their SCADA systems function. In fact, the proposed definition overstates the capabilities of most systems.[58] INGAA recommends adoption of the definition appearing in the Joint Associations' substitute rule, which basically incorporates the definition found in API RP 1168.

[58] At a recent API meeting, PHMSA representatives they said that remote readings of rectifiers, weather monitoring and gas quality, and even remotely read house meters would constitute SCADA and fall under this rule.

B. Proposed 49 C.F.R. § 192.631 (Control Room Management)

1. Proposed 49 C.F.R. § 192.631(a) (General)

<table>
<tr><td colspan="3">(a) General. Each operator of a pipeline facility with at least one controller and control room must have and follow written control room management procedures that implement the requirements of this section. The procedures must be integrated, as appropriate, into the operator's written manuals of procedures required by Sec. 195.402, and written qualification program required by Sec. 195.505. The operator must develop and implement the procedures no later than the dates in the table below.</td></tr>
<tr><td>Control room type</td><td>Develop procedures by:</td><td>Implement procedures by:</td></tr>
<tr><td>(1) Remote operations (control and/or monitoring) of pipelines.</td><td>[insert date 12 months after effective date of final rule].</td><td>[insert date 24 months after effective date of final rule].</td></tr>
<tr><td>(2) Remote operations of equipment within a single site (e.g., pump station).</td><td>[insert date 24 months after effective date of final rule].</td><td>[insert date 30 months after effective date of final rule].</td></tr>
<tr><td>(3) Pipelines with local control only.</td><td>[insert date 30 months after effective date of final rule].</td><td>[insert date 30 months after effective date of final rule].</td></tr>
<tr><td>(4) Control rooms or local control stations placed in service after [insert effective date of the final rule], but before [insert date 12 months after the effective date of final rule].</td><td>12 months after placement in service</td><td>12 months after placement in service</td></tr>
<tr><td>(5) Control rooms or local control stations placed in service after [insert date 12 months after the effective date of final rule].</td><td>Before placing in service.</td><td>Upon placing in service.</td></tr>
</table>

Consistent with General Comment I.A.2. above, all references to “local control,” “local control stations,” “remote operations,” and “remote operations of equipment within a single site,” including references appearing in the procedures development and implementation table, should be stricken in their entirety. The simpler approach, reflected in the Joint Associations’ substitute rule, is to eliminate the implementation in favor of a provision requiring operators to develop procedures within 18 months of the implement those procedures within 36 months of the effective date of the final rule.

2. Proposed 49 C.F.R. § 192.631(b) (Roles and Responsibilities)

(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, each operator must define:

> *(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.*
>
> *(4) A controller's responsibility to provide timely notification and coordination with the operator of another pipeline in a common corridor when a leak or failure is suspected, including upon receipt of a notification from the public concerning a suspected leak on an asset owned or operated by the other company but located in the same common corridor or right-of-way.*
>
> *(5) A method of recording when a controller is responsible for monitoring or controlling any portion of a pipeline facility by implementing an individual console or a system log-in feature or by documenting in the shift records the time and name of each controller who assumed the responsibility during a shift-change or other hand-over of responsibility.*

As detailed in General Comment I.A.2. above, 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. This section also represents an inappropriate and unauthorized attempt to impose hazardous liquid pipeline requirements on natural gas transmission pipelines and LNG facilities, in contradiction of Section 19 of the PIPES Act.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of proposed 49 C.F.R. § 192.631(b).

a. Proposed 49 C.F.R. § 192.631(b)(4)

It is unreasonable to expect a controller to be able to perform all the activities listed in this section, in addition to performing the functions (including functions related to pipeline safety) that are already required. To require controllers to be able to acquire the correct maps, records, right-of-way agreements, and the other documents typically not available to controllers is unreasonable. During a leak or failure the controller is responding to abnormal operating conditions or to emergency operating conditions and must implement a number of procedures including alerting appropriate field operations or others in their organization to respond and conduct those task this rule would shift to controllers. To require controllers to undertake these added tasks shifts additional work burden and diminishes their ability to perform their primary pipeline safety function. Further, the concept that one pipeline failure will lead to the failure of an adjacent near pipeline was categorically rejected by the developers of PHMSA's acclaimed Integrity Management Rule, since the concept, after full vetting during the rulemaking process, was shown to have no safety basis, regardless of the anecdotal example cited in the NOPR.

All communications educating the public provided by pipeline companies, PHMSA and emergency service providers specifically recommend that personnel at the site of an event contact 911 if it appears to be an emergency. Moreover, newer 911 communication systems are "caller location sensitive" assisting the location determination of the event.

b. Proposed 49 C.F.R. § 192.631(b)(5)

For this requirement to be fully considered, its costs should be incorporated into the Regulatory Impact Analysis.

3. Proposed 49 C.F.R. § 192.631(c) (Provide Adequate Information)

(c) Provide adequate information. Each operator must provide each controller with the information necessary for the controller to carry out the roles and responsibilities defined by the operator and must verify that a controller knows the equipment, components and the effects of the controller's actions on the pipeline or pipeline facilities under the controller's control. Each operator must:

As detailed in General Comment I.A.2. above, this section should be deleted in its entirety because it runs counter to congressional direction as expressed in under Section 12 of the PIPES Act. Also, this section should be deleted because there is no data demonstrating that it will increase pipeline safety on natural gas transmission pipelines.[59] INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing information flow to controllers.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of. proposed 49 C.F.R. § 192.631(c).

a. Proposed 49 C.F.R. § 192.631(c)(1)

(1) Provide a controller with accurate, adequate, and timely data concerning operation of the pipeline facility. Wherever a SCADA system is used, the operator must implement API RP-1165 (incorporated by reference, see Sec. 195.3) in its entirety, unless the operator can adequately demonstrate that a provision of API RP-1165 is not applicable or is impracticable in the SCADA system used.

The requirement to provide a controller with "adequate" data concerning the pipeline's operations is a reasonable requirement, yet seems to be very inconsistent with the requirement in proposed Section 192.631(c)(2)(i) to "conduct and document a point-to-point baseline verification" of the entire pipeline system. "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. It is estimated that the safety-related points are significantly outnumbered by the non-safety-related points.

Proposed 49 C.F.R. § 192.631(c)(1) (and several other paragraphs of proposed 49 C.F.R. § 192.631(c)) are also unacceptably silent on what "timely" means in phrases such as "receiving *timely* information," "*timely* verbal communication," etc. INGAA appreciates PHMSA's desire to recognize

[59] Proposed 49 C.F.R. § 192.631(b) is also unacceptably vague. The first sentence states that "Each operator must . . . verify that a controller knows the equipment, components and the effects of the controller's actions on the pipeline or pipeline facilities under the controller's control." The regulatory preamble suggests that in this context "equipment" is limited to items a controller monitors or controls. NOPR, 73 Fed. Reg. at 53087. However, that limitation is not carried into the regulatory text, creating the potential for this term to be interpreted much more broadly in the context of an inspection or audit.

variations among pipeline systems and avoid prescriptive, one-size-fits-all standards;[60] nevertheless, there needs to be some regulatory recognition of the fact that open terms like this raise regulatory uncertainty and provide an avenue for unfair, after-the-fact judgment, i.e., that something was "untimely" solely because there was an undesirable result.

b. Proposed 49 C.F.R. § 192.631(c)

> *(2) Validate that any SCADA system display accurately depicts field equipment configuration by completing all of the following:*

This section repeatedly uses the word "display" but never defines it. In practice, some displays are for purely informational purposes, and since they are not safety-related they should not be subject to these regulations. This area may be appropriate for the development of consensus-based best practices.[61]

c. Proposed 49 C.F.R. § 192.631(c)(2)(i)

> *(i) Conduct and document a point-to-point baseline verification between field equipment and all SCADA system displays to verify 100 percent of the system displays. An operator must complete the baseline verification no later than [insert date three years after effective date of final rule] or by [insert date one year after effective date of final rule] for an operator of a pipeline system containing less than 500 miles of pipeline. An operator may use any documented point-to-point verification completed after [insert date three years before effective date of final rule] to meet some or all of this baseline verification. A point-to-point verification must include equipment locations, ranges, alarm set-point values, alarm activation, required alarm visual or audible response, and proper equipment or software response to SCADA system values.*

This requirement is almost completely unnecessary, and has been estimated to cost approximately $126 million[62] over the required three years for INGAA member companies alone. PHMSA claims this is a performance-language rule. It would seem reasonable that an operator would be permitted to determine which points in his system are necessary to maintain and improve pipeline safety. Instead, PHMSA has made a blanket requirement to verify each and every point. INGAA recommends that only those points contributing to pipeline safety, should be included. This is consistent with existing regulations for the inspection of certain valves determined by the operator as required in the event of an emergency. Further, these verifications should be conducted during the normal course of business, as reflected in each operator's system-specific plans, and not according to a regulatory schedule.

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60 See, e.g., NOPR, Fed. Reg. at 53079.

61 See generally NOPR, 73 Fed. Reg. at 53084.

62 INGAA Survey extrapolated to INGAA membership.

d. Proposed 49 C.F.R. § 192.631(c)(2)(ii)-(iii)

> *(ii) Verify that SCADA displays accurately depict field configuration when any modification is made to field equipment or applicable software and conduct a point-to-point verification for associated changes.*
>
> *(iii) Perform a point-to-point verification as part of implementing a SCADA system change for all portions of the pipeline system or facility affected by the change.*

INGAA agrees with this concept since it is conducted during the normal course of business and does not add an appreciable cost without some potential benefit. However, since this proposed rule does not have defined benefits for the natural gas transmission pipeline industry, this section should not be included in the final rule since it, indeed, does have associated costs.

e. Proposed 49 C.F.R. § 192.631(c)(2)(iv)

> *(iv) Develop a plan for systematic re-verification of the accuracy of the SCADA system display*

Since there is no timetable provided for completion of the plan, INGAA believes this is a compliance issue which should be addressed. If such an endeavor was taken, it is estimated that it would take over three years to complete.

f. Proposed 49 C.F.R. § 192.631(c)(3)

> *(3) Establish a means for timely verbal communication among a controller, management, and field personnel.*

INGAA does not believe that the restriction to "verbal" communication is reasonable. With current communication mechanisms, it would seem to be acceptable to use texting, electronic mail, or other communication media which is effective. INGAA recommends the use of performance language where "how" is not dictated.

g. Proposed 49 C.F.R. § 192.631(c)(4)

> *(4) Identify circumstances that require field personnel to promptly notify the controller. These circumstances must include the identification by field personnel of a leak or situation that could reasonably be expected to develop into an accident if left unaddressed.*

The use of the word "promptly" inside the rule leaves open to inspector interpretation variation once the rule is promulgated, and as such is problematic. An example of the open use of "promptly" in the existing pipeline safety regulations is in reporting of possible reportable incidents, where the word "promptly" is in the regulations, but it has been interpreted over time to mean reported within two (2) hours without due process of the notice-and-comment of an open rulemaking.

h. Proposed 49 C.F.R. § 192.631(c)(5)

> *(5) Define and record critical information during each shift.*

The use of the word "critical" inside the rule, leaves open to inspector interpretation desires once the rule is promulgated, and as such is problematic. For the regulator to leave this undefined when it is clear there are different ideas of what "critical" means to PHMSA is unfair to operators and leaves the final rule overly open to interpretation without due process of the notice-and-comment of an open rulemaking.

i. Proposed 49 C.F.R. § 192.631(c)(8)

(8) Periodically test and verify a backup communication system or provide adequate means for manual operation or shutdown of the affected portion of the pipeline safely.

The word "periodically" is problematic in this provision for the same reasons discussed in the comment to section (c)(5) above. Further, without a scope for "test and verify", operators could spend significant man-hours attempting to comply with a poorly described target. This is particularly true when considering corporate disaster recovery remote sites.

INGAA also requests clarification that this requirement only applies to a pipeline's primary computer systems. Many of the SCADA points only have one communication line.

4. Proposed 49 C.F.R. § 192.631(d) (Fatigue Mitigation)

(d) Fatigue mitigation. Each operator must implement methods to prevent controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities defined by the operator. To protect against the onset of fatigue, each operator must:

INGAA supports the objective of this section since it is included as a requirement in the PIPES Act. It is also possible that pipeline safety benefits could be gained, although no incidents on natural gas transmission pipelines have been attributed to controller fatigue. INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing fatigue mitigation.

a. Proposed 49 C.F.R. § 192.631(d)(1)

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

INGAA supports this provision, and believes it will lead to healthier and more productive controllers contributing to pipeline safety. However, INGAA cautions PHMSA that an operator cannot ensure what a controller does with their respective time away from the workplace.

b. Proposed 49 C.F.R. § 192.631(d)(2)

(2) Educate a controller and his supervisor in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

INGAA believes this requirement is unclear in implementation. We have attempted to locate off-the-shelf, cost effective materials to use in this training, but to date have been unsuccessful. An estimate to have training developed which is specific to pipeline operations is a one-time cost of $125,000.[63] Perhaps, a coordinated effort could be developed among the INGAA members resulting in a one time cost of $250.000, with a maintenance cost of $25,000 per year.

[63] INGAA Survey extrapolated to INGAA membership

c. Proposed 49 C.F.R. § 192.631(d)(3)

(3) Train a controller and his supervisor to recognize and mitigate the effects of fatigue;

INGAA recommends adopting the provision in the Joint Associations' substitute rule: "Train a controller and his supervisor to recognize and mitigate the effects of fatigue."

d. Proposed 49 C.F.R. § 192.631(d)(4)

(4) Implement additional measures to monitor for fatigue when a single controller is on duty;

INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing fatigue mitigation.

5. Proposed 49 C.F.R. § 192.631(e) (Alarm Management)

(e) Alarm management. Each operator using a SCADA system must assure appropriate controller response to alarms and notifications. An operator must:

As detailed in General Comment I.A.2. above, this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act. Also, this section should be deleted because it will not increase pipeline safety. INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing alarm management.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of proposed 49 C.F.R. § 192.631(e).

a. Proposed 49 C.F.R. § 192.631(e)(1)

(1) Review SCADA operations at least once each week for:

INGAA believes that review once each week is completely unreasonable and offers no value. The time period is simply too short for meaningful data to be collected, is extraordinarily draining on personnel, and will detract from pipeline safety activities by diverting resources to meetings and reviews which will provide no meaningful results. None of section (e)(1) should be implemented. INGAA estimates the cost of implementing this requirement as proposed to be $71,501,000 per year,[64] not including an additional full time equivalent employee to collect and attempt to make sense of the data, which is estimated at $120,000 per year per INGAA member operator. This is estimated to be an annual cost of $32,000,000 annually[65] for INGAA members.

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[64] INGAA Survey extrapolated to INGAA membership.

[65] INGAA Survey extrapolated to INGAA membership.

b. Proposed 49 C.F.R. § 192.631(e)(1)(i)

(i) Events that should have resulted in alarms or event indications that did not do so;

It is unclear how this is to be accomplished. In fact, this resembles a circular argument which cannot be attained. How is one to evaluate an event if there is no record, mechanism, or resulting alarm to indicate the event occurred? The compliance aspects of this section are difficult to comprehend and should be eliminated. INGAA estimates it would cost each operator $150,000 per year to implement some sort of system to track these events, and ongoing annual costs of $50,000 to train operators and field personnel to recognize and categorize these events. These costs would be borne by each INGAA member company. This is estimated to be an annual cost of $10,000,000 annually[66] for INGAA members.

c. Proposed 49 C.F.R. § 192.631(e)(1)(ii)

(ii) Proper and timely controller response to alarms or events;

This section states that each alarm shall be reviewed each week for "proper and timely controller response". Notwithstanding the definitions for "proper" and "timely", it is estimated that the cost to implement this section is $2,015,000 annually[67]. This cost would be spread across individual controllers and their immediate management.

d. Proposed 49 C.F.R. § 192.631(e)(1)(iii)

(iii) Identification of unexplained changes in the number of alarms or controller management of alarms;

The collection of this data would be a positive data set to possess, but unfortunately has no bearing on pipeline safety. Each operator experiences hundreds of alarms each day, most of which are not related to pipeline safety. Identifying and assessing each of these unexplained alarms is a costly and time-consuming process, estimated at $1,540,000 annually.[68]

e. Proposed 49 C.F.R. § 192.631(e)(1)(iv)

(iv) Identification of nuisance alarms;

The use of the term "nuisance alarm" is unknown to INGAA and no definition in the proposed rule was provided. We think this term would include alarms as non-pipeline-safety-related as simple operational alerts or other operating or commercial issue completely unrelated to pipeline safety. The identification of these "nuisance alarms" would require a review of each alarm each week, at an estimated cost of $1,946,000 annually.[69]

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[66] INGAA Survey extrapolated to INGAA membership.

[67] INGAA Survey extrapolated to INGAA membership.

[68] INGAA Survey extrapolated to INGAA membership.

[69] I INGAA Survey extrapolated to INGAA membership.

f. Proposed 49 C.F.R. § 192.631(e)(1)(v)

(v) Verification that the number of alarms received is not excessive;

The meaning of "excessive" is unclear, and can mean different things to different operators. Additionally, all critical alarms are responded to in the manner each operator requires, but the proposed rule requires resources to be directed to every conceivable alarm, causing a significant impact on operator's staff. INGAA strongly recommends that PHMSA implement a differential in the final rule between an "alarm" and a "pipeline safety alarm". Clearly the proposed rule's scope in this one section is so broad as to cause significant impact on an operator's staff with no concurrent pipeline safety benefits and would be difficult to comply with since no operator would know what "excessive" means to an inspector. The estimated annual implementation cost to comply for this section is $24,000,000 annually[70] when staff increases are accounted for.

g. Proposed 49 C.F.R. § 192.631(e)(1)(vi)

(vi) Identification of instances in which alarms were acknowledged but associated response actions were inadequate or untimely;

In effect, this provision would require an analysis of response for each and every alarm received. Depending on how a system is configured, there could be thousands of alarms in a week (both safety-related and other). This level of investigation and analysis will result in an approximate annual cost of $2,000,000 [71]with no improvement in pipeline safety.

As for the evaluation standard — whether the response to an alarm was "inadequate or untimely" — INGAA reiterates its comment concerning the use of the word "timely" in proposed 49 C.F.R. § 192.631(c).

h. Proposed 49 C.F.R. § 192.631(e)(1)(vii)

(vii) Identification of abnormal or emergency operating conditions and a review of controller response actions;

It is appreciated that one term in this section has a common regulatory definition, and the scope is understood. The estimated annual cost for complying with this section is $24,000,[72] mainly due to the limited number of abnormal operating conditions.

i. Proposed 49 C.F.R. § 192.631(e)(1)(viii)

(viii) Identification of system maintenance issues;

This section needs a scope definition. Could this include every known anomaly? If so, the costs of doing this each week with no benefit are estimated at $10,000,000 annually.[73]

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[70] INGAA Survey extrapolated to INGAA membership.

[71] INGAA Survey extrapolated to INGAA membership.

[72] INGAA Survey extrapolated to INGAA membership.

[73] INGAA Survey extrapolated to INGAA membership.

j. Proposed 49 C.F.R. § 192.631(e)(1)(ix)

(ix) Identification of systemic problems, server load, or communication problems;

INGAA respectfully requests the term "systemic problem" be defined. The other items listed, server load and communication problems, are handled in our normal course of business and have never led to a reportable incident. Therefore whatever costs are attributed to this section have no commensurate benefits.

k. Proposed 49 C.F.R. § 192.631(e)(1)(x)

(x) Identification of points that have been taken off scan or that have had forced or manual values for extended periods; and

INGAA respectfully requests the term "extended" be defined to provide opportunity for notice-and-comment in an open and transparent manner.

l. Proposed 49 C.F.R. § 192.631(e)(1)(xi)

(xi) Comparison of controller logs or shift notes to SCADA alarm records to identify maintenance requirements or training needs.

Requiring operators to compare what will almost certainly be paper records with either electronic or other paper records, each week, for all recorded issues, and then to consider each record for maintenance requirements or training needs, is simply an overwhelming effort with unknown benefits estimated annual costs of $6,400,000[74] to staff up and execute the various comparisons.

m. Proposed 49 C.F.R. § 192.631(e)(2)

(2) Review SCADA configuration and alarm management operations at least once each calendar year but at intervals not to exceed 15 months. At a minimum, reviews must include consideration of the following factors:

This section should be deleted in its entirety since Congress did not contemplate this addition and there is no demonstrable safety benefit to be gained or cost-benefit justification.

n. Proposed 49 C.F.R. § 192.631(e)(2)(i)

(i) Number of alarms;

It is unclear how this requirement impacts pipeline safety, or even how to review it. INGAA estimates there are 8640 daily alarms being managed by natural gas transmission pipeline operators, and to evaluate all of these each year, regardless of whether the alarms are in response to a safety condition, is unreasonable. INGAA estimates the annual review of these alarms would cost $8,000,000[75] with no demonstrable safety benefit.

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[74] INGAA Survey extrapolated to INGAA membership.

[75] INGAA Survey extrapolated to INGAA membership.

o. Proposed 49 C.F.R. § 192.631(e)(2)(iii)

(iii) Unnecessary alarms;

This requirement will require the analysis of each alarm each operator receives each year. This will require immense numbers of hours being spent, estimated to cost approximately $13,000,000 annually.[76] Further, as noted above, it is unclear precisely what should be analyzed since there is no definition for "unnecessary alarms". It can be expected that each operator will have a different definition, resulting in differing efforts to comply. This is not consistent with an effective performance-language rule.

p. Proposed 49 C.F.R. § 192.631(e)(2)(iv)

(iv) Individual controller's performance changes over time regarding alarm or event response;

Since this is a completely new regulatory requirement, well beyond the requirements in the existing operator qualification rule, there is no infrastructure existing to comply. The preamble to the proposed rule was very clear that PHMSA was attempting to build on existing programs, and this proposed regulation does not do so.

q. Proposed 49 C.F.R. § 192.631(e)(2)(v)

(v) Alarm indications of abnormal operating conditions;

The proposed rule implies that alarms indicate an abnormal operating condition. This is simply not true. Only a small percentage of overall alarms on most systems are safety-related, and of those, none of them tell a controller that an abnormal operating condition is occurring or has occurred. An abnormal operating condition can only be determined by investigation and review of whether the criteria to have an abnormal operating condition have been met. Therefore, it is impossible for an operator to meet the requirements of this section.

r. Proposed 49 C.F.R. § 192.631(e)(2)(vi)

(vi) Recurring combinations of abnormal operating conditions and the inclusion of such combinations in controller training;

INGAA believes this requirement can be accomplished cost-effectively, although we are not aware of a combination of abnormal operating conditions ever occurring, so there should be no expected benefits attained. Developing training for combinations of abnormal operating conditions will require a large number of operator's controllers dedicating significant time to train on an extraordinarily rare event is not cost-beneficial and cannot reasonably be expected to increase pipeline safety.

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[76] INGAA Survey extrapolated to INGAA membership.

s. Proposed 49 C.F.R. § 192.631(e)(2)(viii)

(viii) Individual controller workload;

This section seems to require an operator to evaluate each individual's capabilities, which will vary by controller, each year against what that controller has done and can do, and then perform all the required documentation. If so, this is unreasonable. It is estimated that this section will cost approximately $484,000 annually.[77]

t. Proposed 49 C.F.R. § 192.631(e)(2)(x)

(x) Verification of correct alarm set-point values.

INGAA agrees with this requirement if there is no time requirement for compliance and the work can be accomplished in the normal line of work and not require extra allocations of scarce resources beyond what is spent in the normal pursuit of pipeline safety. It is estimated that this requirement will cost natural gas transmission pipeline operators $4,234,000 annually.[78]

u. Proposed 49 C.F.R. § 192.631(e)(3)

(3) Promptly address all deficiencies identified in the weekly and calendar year SCADA reviews.

INGAA recommends again that the term "promptly" be defined. Most "deficiencies" will be non-safety related issues, and have a huge cost with no attendant safety benefits. We are unable to estimate these costs since the variables PHMSA proposes being evaluated are unknown. PHMSA is again reminded that in spite of the proposed rule's claim that most requirements in the proposed rule are building on existing processes, this is simply not true.

6. Proposed 49 C.F.R. § 192.631(f) (Change Management)

(f) Change management. Each operator must establish thorough and frequent communications between a controller, management, and field personnel when planning and implementing physical changes to pipeline equipment and configuration. Field personnel must be required to promptly notify a controller when emergency conditions exist or when performing maintenance and making field changes.

As detailed in General Comment I.A.2. above, this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act. Also, this section should be deleted because it will not increase pipeline safety.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of proposed 49 C.F.R. § 192.631(f).

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[77] INGAA Survey extrapolated to INGAA membership.

[78] INGAA Survey extrapolated to INGAA membership.

a. Proposed 49 C.F.R. § 192.631(f)(1)

> *(1) Maintenance procedures must include tracking and repair of controller-identified problems with the SCADA system or field instrumentation to provide for prompt response.*

This is an added process that is handled verbally or through other communication channels with management currently. This requirement in the proposed rule will simply add additional paperwork with no attendant safety benefits. It can be easily concluded that controller-related problems with the SCADA system or field instrumentation are being handled properly with existing operator's operating plans since there is no attendant evidence that pipeline safety has been compromised.

b. Proposed 49 C.F.R. § 192.631(f)(2)

> *(2) SCADA system modifications must be coordinated in advance to allow enough time for adequate controller training and familiarization unless such modifications are made during an emergency response or recovery operation.*

To require training all controllers on each change prior to the change taking place could take considerable time due to shift issues and the vagaries of the working hours of controllers. Holding up changes for formal training of each and every controller is unreasonable and could result in pipeline safety issues not being addressed in a timely fashion.

c. Proposed 49 C.F.R. § 192.631(f)(3)

> *(3) An operator shall seek control room participation when pipeline hydraulic or configuration changes are being considered.*

In almost every instance, pipeline control room management is currently consulted when pipeline hydraulic or configuration changes are being considered. If the consultation of management meets the intent of the proposed rule, INGAA has no issues. However, if this is not clearly outlined in any enforcement guidance, we will view this section as unreasonable since controllers themselves are not commonly consulted since their immediate management is regularly consulted.

d. Proposed 49 C.F.R. § 192.631(f)(5)

> *(5) Changes to alarm set-point values, automated routine software, and relief valve settings must be communicated to the controller prior to implementation.*

It is unclear how this requirement contributes to pipeline safety, particularly the relief valve settings. Currently most, if not all, of the settings which are automatically operated without any human intervention, such as relief valves, are set and maintained by field operations without controller input, since there is no opportunity for controller actions on those devices. This arrangement has worked very well for the life of the natural gas transmission pipeline industry, with no incidents recorded that would have been prevented by this proposed requirement.

e. Proposed 49 C.F.R. § 192.631(f)(6)

(6) An operator must thoroughly document and keep records for each of these occurrences.

It is unclear why PHMSA chose to insert the word "thoroughly" in the requirement to document and keep records. INGAA finds this additional word unnecessary.

7. Proposed 49 C.F.R. § 192.631(g) (Operating Experience)

As detailed in General Comment I.A.2. above, this section should be deleted in its entirety because it runs counter to congressional direction as expressed in Section 12 of the PIPES Act. Also, this section should be deleted because it will not increase pipeline safety. INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing alarm management.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of. proposed 49 C.F.R. § 192.631(g).

a. Proposed 49 C.F.R. § 192.631(g)(1)

(1) Each operator must review control room operations following any event that must be reported as an accident pursuant to Sec. 195.50 determine and 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;

(vi) SCADA system performance;

(vii) Accuracy, timeliness, and portrayal of field information on SCADA displays; and

(viii) Simulator or non-simulator training programs.

There are approximately 100 reportable incidents each year on natural gas transmission pipelines. This requirement would necessitate a review of each of these incidents by a cross-sectional team of employees to ensure all aspects were considered. It is estimated that the annual cost to comply with this requirement is $80,000.[79]

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[79] INGAA Survey extrapolated to INGAA membership.

b. Proposed 49 C.F.R. § 192.631(g)(2)

(2) Each operator must establish a definition or threshold for close-call events to evaluate event significance. For those events the operator determines to be significant, the operator must conduct the review required by paragraph (g)(1) of this section and the operator must share the information with all controllers.

This requirement is unreasonable on several levels. Holding individual operators responsible for defining "close-call events" will inevitably lead to differing definitions, which will inevitably lead to compliance and enforcement inconsistencies. INGAA respectfully requests that PHMSA develop a definition for "close-calls" and then use the rulemaking process to propose any reporting requirements.

8. Proposed 49 C.F.R. § 192.631(h) (Training)

As detailed in General Comment I.A.2. above, this section should be deleted in its entirety because it exceeds Congressional direction and PHMSA's authority under Section 12 of the PIPES Act. Also, this section should be deleted because it will not increase pipeline safety. INGAA urges adoption of the Joint Associations' substitute rule, which contains provisions addressing alarm management.

Comments appearing below with regard to specific subsections should not be interpreted as agreement with the remaining subsections of. proposed 49 C.F.R. § 192.631(h).

a. Mandatory Periodic Review of Training Program

(h) Training. Each operator must establish a 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 must train each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

INGAA finds the proposed requirement to "…review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months" to be unreasonable and not based on any known facts. The national consensus standard, ASME B31Q, established tasks to be covered by a qualified controller, and used a scientifically accepted method for determining what frequency those controllers should be re-qualified on those tasks. Each controller task was determined to have a re-qualification interval of three years. Further, of approximately 170 tasks for the natural gas transmission pipeline industry contained within ASME B31Q, only two had re-qualification intervals of one year, with all the other tasks having intervals of either three or five years, as determined by subject matter experts using the aforementioned scientific method. It should be noted that INGAA does not believe the interval could not be one year, but instead given that a rigorous analysis overwhelmingly resulted in intervals of either three years or five year intervals, it would seem unlikely that a one year interval is the proper conclusion. INGAA requests PHMSA to use an accepted method for determining the interval in this section as well to uphold the standards of a national consensus standard-setting body.

b. Proposed 49 C.F.R. § 192.631(h)(4)

> *(4) On-site visits by controllers to a representative sampling of field installations similar to those for which each controller is responsible to familiarize themselves with the equipment and with station personnel functions.*

INGAA does not understand the prescriptive requirement that on-site visits shall be made by controllers to field installations. On-site visits should be determined by the operator as controller qualification needs are evaluated. Further, guidance is not provided for how often field visits should be considered, under what circumstances they should be considered, or even the applicability of a field visit if an individual controller had a prior career in field operations, which is frequently the case. The cost of implementing this proposed requirement as written is estimated to be $450,000 annually.[80]

c. Proposed 49 C.F.R. § 192.631(h)(5)

> *(5) Review of procedures for pipeline operating setups that are periodically, but infrequently used.*

While INGAA feels this proposed requirement could be valuable in a theoretical manner, the very infrequency of the procedures being required to be reviewed will lead to a negative cost-benefit, particularly when there is no evidence that this review will improve pipeline safety. It is estimated that this review will cost $28,000 annually,[81] with a one-time cost of $16,000[82] for a pipeline company. This would result in a one-time cost of $800,000 and an annual cost of $1,400,000 for INGAA members.

d. Proposed 49 C.F.R. § 192.631(h)(6)

> *(6) Hydraulic pipeline training that is sufficient to obtain a thorough knowledge of the pipeline system, especially during the development of abnormal operating conditions.*

INGAA does not believe that a "thorough" knowledge of the pipeline system from a hydraulics perspective is necessary for controllers. A working knowledge is sufficient, and is implicitly included in the qualification programs of individual operators. It is estimated that this proposed requirement would have a cost of $229,000 annually, with a one-time cost of $384,000 for a pipeline company. This would result in a one- time cost of $11,450,000[83] and annual cost of $19,200,000[84] for INGAA members.

e. Proposed 49 C.F.R. § 192.631(h)(7)

> *(7) Site specific training on equipment failure modes.*

Site specific training on each equipment failure mode, given the vast differences in equipment vintages and geographic variability, is overwhelming and will add little value. Some operators have developed site specific plans for internal corrosion at great cost, but with specific benefits identified. A

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80 INGAA Survey extrapolated to INGAA membership.

81 INGAA Survey extrapolated to INGAA membership.

82 INGAA Survey extrapolated to INGAA membership.

83 INGAA Survey extrapolated to INGAA membership.

84 INGAA Survey extrapolated to INGAA membership.

general requirement such as the one proposed here is unnecessary and will not generate benefits anywhere near the one-time estimated cost of $124,486,000[85]. INGAA also continues to question how PHMSA expects controllers to absorb and retain all the incremental knowledge required by the proposed rule, keep up with every site specific change,[86] maintain all the incremental required records, and continue to safely operate the pipelines.

9. Proposed 49 C.F.R. § 192.631(*i*) (Qualification)

(i) Qualification. An operator must have a program in accordance with subpart G of this part to determine that each controller is qualified. An operator's procedures for the qualification of controllers must include provisions to:

INGAA supported the development of 49 C.F.R. 192 Subpart N[87] when it was initially promulgated, and still believes it to be valid, including as it applies to controllers. Additionally, INGAA supports the use of the national consensus-based standard ASME B31Q, which addresses controller issues as well. INGAA does not see the need for a qualification section in this proposed rule, and notes the PIPES Act does not contemplate this section, either.

a. Proposed 49 C.F.R. § 192.631(*i*)(2)

(2) Evaluate a controller's physical abilities, including hearing, colorblindness (color perception), and visual acuity, which could affect the controller's ability to perform the assigned duties.

INGAA understands the need to evaluate controllers for their abilities which could affect performance. However, these issues were addressed and debated at length, with subject matter experts included in the discussions, at both the Subpart N deliberations and, more recently, in the development of ASME B31Q. In neither instance was it determined that these considerations be made, primarily since controllers are able to overcome hearing, color blindness, and general visual acuity issues through other channels which are viable and effective. Since the CCERT team reviewed the OQ rule and visited extensively with the B31Q Committee It is unclear that after why the CCERT team would include this in the proposed rule. If there is additional knowledge or technical considerations that the large number of experts did not consider, PHMSA should make that known prior to including this section in a final rule.

b. Proposed 49 C.F.R. § 192.631(*i*)(3)

(3) Evaluate a controller's qualifications at least once each calendar year, but at intervals not to exceed 15 months.

INGAA finds the proposed requirement to “Evaluate a controller’s qualifications at least once each calendar year, but at intervals not to exceed 15 months” to be unreasonable and not based on any known facts. The national consensus standard, ASME B31Q, established tasks to be covered by a

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85 INGAA Survey extrapolated to INGAA membership.

86 Due to the size and complexity of many pipelines, any site specific training, will quickly become dated. For example, one INGAA member has over 2,000 meter stations, 10,000 farm taps, 30 compressor stations and 16,000 miles of pipelines. If controllers had to visit all those sites, they would never complete their tour, let alone have time for gas control.

87 49 C.F.R. §§ 192.801-.809.

qualified controller, and used a scientifically accepted method for determining what frequency those controllers should be re-qualified on those tasks. Each controller task was determined to have a re-qualification interval of three years. Further, of approximately 170 tasks for the natural gas transmission pipeline industry contained within ASME B31Q, only two had re-qualification intervals of one year, with all the other tasks having intervals of either three or five years, as determined by subject matter experts using the aforementioned scientific method. It should be noted that INGAA does not believe the interval could not be one year, but instead given that a rigorous analysis overwhelmingly resulted in intervals of either three years or five year intervals, it would seem unlikely that a one year interval is the proper conclusion. INGAA requests PHMSA to use an accepted method for determining the interval in this section as well, to at least uphold the standards of a national consensus standard-setting body. Finally, since this proposed requirement is so prescriptive in nature without technical justification, INGAA requests that PHMSA use either performance-language or prescriptive-language in the final rule. The constantly shifting from one to the other and back again is confusing and does not lead to increased pipeline safety.

c. Proposed 49 C.F.R. § 192.631(*i*)(4)

(4) Implement methods to address gradual degradation in performance or physical abilities in a controller.

INGAA is unaware of how to implement this proposed requirement in a fair manner. The existing OQ rule does not address gradual degradation in performance, nor does the national consensus-based standard ASME B31Q. There is no demonstrated need or safety benefit to be expected by the promulgation of this proposed requirement. INGAA respectfully requests PHMSA to withdraw this section.

d. Proposed 49 C.F.R. § 192.631(*i*)(8)

(8) Prohibit individuals without a current controller qualification from performing the duties of a controller.

This requirement is baffling, particularly given that PHMSA's own operator qualification rules permit non-qualified individuals to perform covered tasks if they are observed by a qualified individual. Yet this proposed section precludes this flexibility, with no discussion of why the flexibility in the existing pipeline safety regulations is denied. Again, this is a prescriptive requirement with no technical justification. Further, it is unclear how a controller would become qualified to operate a pipeline without actually doing it under the guidance of a qualified controller. Simply watching a qualified controller operate a pipeline and undergo training will not qualify a controller. INGAA estimates this proposed section to have a cost of $3,000,000 annually.[88]

88 INGAA Survey extrapolated to INGAA membership.

10. Proposed 49 C.F.R. § 192.631(j) (Validation)

> *(j) Validation. An operator must have a senior executive officer validate by signature not later than the date by which control room management procedures must be implemented (see paragraph (a) of this section), and annually thereafter by June 15 of each year, that the operator has:*

Section (j) should be deleted in its entirety. This section is inconsistent with congressional direction and will not increase pipeline safety. However, INGAA understands the value of proposed Section 192.631(j)(3), since it could engender increased confidence and oversight of the respective control rooms and associated processes. Yet there is no demonstrable safety benefit discussed in the proposed rule and there are no tangible benefits to be gained by promulgating this section.

a. Proposed 49 C.F.R. § 192.631(j)(1)

> *(1) Conducted a review of controller qualification and training programs and has determined both programs to be adequate;*

This proposed requirement is unnecessary and inconsistent with current Subpart N requirements[89] and the proposed requirement provides no safety benefits.

b. Proposed 49 C.F.R. § 192.631(j)(2)

> *(2) Permitted only qualified controllers to operate the pipeline;*

INGAA encourages PHMSA to reference the comments in proposed section (i)(8) above as they relate to this proposed section.

c. Proposed 49 C.F.R. § 192.631(j)(3)

> *(3) Implemented the requirements of this section;*

INGAA references the above comments on proposed Section 192.631(j).

d. Proposed 49 C.F.R. § 192.631(j)(4)

> *(4) Continued to address ergonomic and fatigue factors;*

INGAA contends there is no technical justification or demonstrated safety benefits by the inclusion of this proposed section. INGAA respectfully requests PHMSA to show tangible benefits prior to including this proposed requirement in any final rule.

CONCLUSION

INGAA believes that when Congress enacted Section 12 of the PIPES Act, it envisioned a control room management rule that was limited in scope. The final rule should reflect that limitation. The final regulations should not reach to "remote locations," where the safety benefit of additional or regulations has not been examined or substantiated. Moreover, most of the proposed rule deals with items outside the

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89 See n. 87, *supra*.

scope intended by Congress. These substantive areas should continue to be developed as "best practices" through industry consensus. INGAA encourages PHMSA to move forward with this in mind.

INGAA appreciates the opportunity to comment on this important proposed rule, and sincerely hopes these comments are considered with the focus on pipeline safety benefits that INGAA maintained as the focus as the comments were prepared. Improving pipeline safety is in everyone's best interest, provided any regulatory mandates pass a reasonable cost-benefit analysis prior to promulgation.

Finally, INGAA offers its continued assistance in the development of this rule. We and our member companies have been actively involved in all aspects of the control room management rulemaking process over the past six-plus years, and continue to look forward to a final rule consistent with congressional direction.

Respectfully submitted,

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