January 8, 2016

VIA ELECTRONIC FILING

U.S. DOT Docket Management System
West Building Ground Floor
Room W12-140
1200 New Jersey Avenue, SE,
Washington, DC 20590-0001
DC 20590–0001,

Re: Docket No. PHMSA 2010 – 0229: Proposed Rule on Pipeline Safety: Safety of Hazardous Liquids Pipelines; Federal Register Vol. 80, No. 197 (Tuesday, October 13, 2015); RIN 2137-AE66

Dear Sir/Madam,

The Gas Processors Association ("GPA" or the "Association") appreciates the opportunity to provide comments to Pipeline and Hazardous Materials Safety Administration's (PHMSA) Notice of Proposed Rulemaking (NPRM) on Hazardous Liquids Pipeline Safety.[1]

GPA is a non-profit trade organization made up of over 100 corporate members. GPA's membership accounts for approximately 92 percent of all natural gas liquids ("NGLs") produced by the midstream energy sector in the United States. GPA members also produce, gather, transport and market natural gas and crude oil.

On October 18, 2010 PHMSA published "*Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines,*" Advance Notice of Proposed Rulemaking, 75 FR 63774. While GPA did not respond directly, many of its member companies are also members of API and AOPL and provided comments in the joint submittal dated February 18, 2011.

On Tuesday, October 13, 2015 a Notice of Proposed Rulemaking ("Notice") was published in the Federal Register concerning several substantial proposed changes to the pipeline safety rules for hazardous liquids pipelines. PHMSA has grouped these proposals into seven primary categories: (1) Extend certain reporting requirements to gravity lines; (2) Extend certain reporting requirements to all hazardous liquid gathering lines; (3) Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events; (4) Require periodic assessments of pipelines that are not already covered under the integrity management (IM) program requirements; (5) Expand the use of leak detection systems on hazardous liquid pipelines to mitigate the effects of failures that occur outside of HCAs; (6)

[1] *Pipeline Safety: "Safety of Hazardous Liquid Pipelines,"* Notice of Proposed Rulemaking, 80 FR, 61610 (October 13, 2015).

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Modify the IM repair criteria, both by expanding the list of conditions that require immediate remediation and consolidating the timeframes for remediating all other conditions, and apply those same criteria to pipelines that are not subject to the IM requirements, with an adjusted schedule for performing non-immediate repairs; and, (7) Increase the use of inline inspection tools by requiring that any pipeline that could affect a high consequence area be capable of accommodating these devices within 20 years.

GPA members have a significant interest in all aspects of the proposal. GPA has provided comments in greatest detail for those issues of greatest overall negative impact to its membership, would result in little or no safety benefit, or may be unattainable as proposed while greatly burdening PHMSA and its state partner resources in addition to the industry. Further, we are confident the actual total cost of the proposal far exceeds the $22 million plus per year cost that will be incurred by industry as proffered by the PHMSA. Moreover, little, if any, justification has been provided to demonstrate how or why the proposed changes are reasonable or necessary for some of the proposals. For other proposals, GPA offers its support or asks PHMSA to provide further clarification in the final rule.

PHMSA has portrayed the proposed rulemaking as having seven distinct components. While this is an accurate portrayal from a purely technical perspective, many of the proposals cross over different sectors of the transportation chain and carry dramatically different effects. For these reasons, GPA has further subdivided some of the proposals and offers the following comments.

A. <u>Addition of two New Definitions</u>

GPA supports, with clarification, PHMSA's proposal to include two new definitions into the CFR. We do not oppose PHMSA's intent to include transportation of biofuels oversight into its regulatory program. With respect to the proposed definition of "*Significant Stress Corrosion Cracking"* ("SCC"), GPA understands PHMSA's intent to raise awareness of this potential threat. We harbor concerns over the use of the word significant even with the additional descriptions PHMSA is including. The proposed descriptors do not begin to include all of the variables which influence SCC behavior and is therefore, very incomplete for assigning an "actionable" status for all instances. The term "significant" is very subjective and, thus it is very conceivable there will be differences of opinion in the interpretation. For these reasons, we believe PHMSA should seek another "qualifying method" which can be used to identify those SCC problems that warrant the required actions in the proposed §195.422(1)(vi) and §195.452(h)(4)(E), such as those found in published standards and other available research.

B. <u>Gathering Lines</u>

<u>Extension of the Reporting Requirements</u>

PHMSA has proposed that operators of non-regulated gathering lines be subjected to the reporting requirements contained within Subpart B of 49 CFR Part 195. Within the proposal PHMSA has identified the need to modify the data collection activities associated with Annual

Reports, Safety-related Condition Reports, and Accident Reports to reflect the adjusted burden hours needed to comply with the proposal. Not mentioned is the burden associated with compliance of §§195.61 &195.64; the requirements to obtain an Operator Identification number ("OpID") and the ongoing costs related to changes within the system through construction or mergers, divestitures, and acquisitions. While many operators have maps of newer installations, geospatial information on legacy gathering lines may not be available. Again, no cost impacts seem to have been considered for these requirements. We assume that because these code provisions were introduced after the publication of the ANPRM, the Regulatory Impact Analysis (RIA) was not updated to reflect their inclusion. The data PHMSA would obtain by requiring the reporting of either of these provisions would not contribute in any meaningful way to making future fact-based, risk-based decisions. They should not be included in a data collection effort.

While the collection is authorized by statute as PHMSA noted in the Preamble, it should also be recognized that the GAO[2] report recommended the data collection be conducted "subsequent to an analysis of the benefits and industry burdens associated with such data collection." PHMSA has stated in the NPRM that the burden created by requiring Annual Reports for gathering lines that are not currently regulated will only impact 23 operators and that "Operators currently submitting annual reports will not be otherwise impacted by this rule." GPA disagrees with the last statement. Operators currently filing Annual Reports {OMB Control Number 2137-0614} that also have gathering that is not currently regulated will experience increased costs and burden to collect data from the "field" and incorporate it into the reporting management process. As PHMSA notes, this entails data for some 30,000 – 40,000 miles of pipeline. The largest burden will be incurred the first year, but there will be associated costs each year as systems are expanded or pipe is replaced or abandoned.

GPA supports PHMSA's goal of collecting data necessary to make informed rulemaking decisions. We believe this can be accomplished by developing an abbreviated form which includes only the data contained in Sections A, D, H, J, N, & O of the current Annual Report (F 7000.1-1) with the addition of the M1 data fields (modified) from the Gas Transmission Annual Report (F7100.2-1). The information collected annually through this process could then be paired with Accident reporting on Form F 7000-1 (rev 7-2014). Once sufficient data is collected (e.g. a minimum of five years), PHMSA can analyze the data to determine if regulatory expansion is necessary and if so, to what degree. The reporting of safety-related conditions on a sporadic basis would likely provide little value in reaching conclusions from data driven analysis. Telephonic notice would add no value to this initiative, as very few details useful for analysis are typically available within the one hour timeframe required for telephonic notification.

While the data and cost associated with the actual filing of the report are included in the analysis, GPA feels PHMSA has neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms. In many cases, the information

[2] http://www.gao.gov/products/GAO-12-388

may not be recorded or may not have been provided during mergers or acquisitions. PHMSA has not communicated its expectations for these situations. GPA requests that PHMSA clarify their expectations regarding the specific pipe details. If it is PHMSA's expectation that operators physically excavate to obtain the data, the costs will reach into the hundreds of millions.

GPA encourages PHMSA to undertake the modified data collection effort described above for future use in determining whether further oversight is warranted, and if so, to what degree.

Performing Assessments on Rural Gathering

PHMSA has stated it is basing its proposal to require assessments and leak detection on the findings contained in the congressionally[3] mandated study titled "Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines," that was performed by the Oak Ridge National Laboratory and published on May 8, 2015. PHMSA is proposing additional regulations to ensure the safety of hazardous liquid gathering lines. That study contained no identified shortcomings, nor drew any conclusions regarding a need to promulgate further regulations.

The RIA assumes only 8% would be pressure tested versus instrumented in-line inspection ("ILI"). The RIA makes no distinction on the ability for rural high consequence areas ("HCA") affected gathering to be subjected to ILI versus transportation lines. The RIA does not consider the mobilization costs associated with conducted assessments using ILI. Costs to conduct ILI assessments are typically presented on a per mile basis with mobilization averaged in. We assume that is the approach used in the RIA. However, mobilization costs are essentially the same for a one mile ILI run or a two hundred mile assessment. So, cost per mile for isolated short runs is significantly higher when presented on a per mile basis than the $5150 figure used. In fact, one of our member companies has figures showing cost per mile closer to $10,000, or at least $200,000/20 miles of pipeline for recent assessments of rural gathering.

Regulated segments of rural gathering are defined in §195.11 in part as;

…an onshore gathering line in a rural area that meets all of the following criteria--

(1) Has a nominal diameter from 6 5/8 inches (168 mm) to 8 5/8 inches (219.1 mm);
(2) Is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in § 195.6; and
(3) Operates at a maximum pressure established under § 195.406 corresponding to--
  (i) A stress level greater than 20-percent of the specified minimum yield strength of the line pipe

[3] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (ACT), Section 21, Gas and hazardous liquid gathering lines.

PHMSA conducted extensive analysis preceding the 2008 rulemaking[4] to determine which rural gathering lines posed the potential to cause the most harm from a release. As a result, portions of gathering lines or gathering systems are regulated. Gathering systems tend to consist of hundreds of miles of short lines segments interconnected and used to transport product from a multitude of wells. This can result in extreme pressure fluctuations within the systems with the lift unit adjusting to optimize production from the well. Multiply this action for numerous wells and the flow characteristics needed to propel an ILI tool become unmanageable or nonexistent.

The only acceptable assessment methods PHMSA is proposing, without prior notification, is ILI with the ability to detect "… corrosion and deformation anomalies, including dents, cracks, gouges, and grooves,…" As PHMSA is aware, single tools capable of detecting all of these different anomalies are very limited in availability and are possible by "training" the various components together. The ability to do this with small diameter, such as the gathering lines targeted (6.625" – 8.625") is not available. Even if it were, the tool length would likely not be able to negotiate most gathering lines. Thus, multiple tools would have to be run, whether a particular threat exists or not, to satisfy the rule as proposed.

PHMSA only included costs associated with one run per assessment versus the two or three different ILI tools that will be required to assess for all of the threats PHMSA has included in the proposal. Under the current integrity management assessments required, the operator is directed to explain the assessment method selected and the risk factors considered. As proposed, there is no consideration of the actual threat(s) for a particular pipeline. Thus, there is no permissible deviation from running multiple ILI tools. For this reason, GPA feels the costs to assess an isolated 1 mile section of regulated gathering could cost significantly more than conducting a hydro-static test ("Hydro Test") if three mobilization fees are incurred for the ILI process.

PHMSA is proposing to require notification for any assessment that does not use ILI. We are confident that it will take member companies more than the one hour PHMSA has allocated to develop the justification necessary to demonstrate the impracticability and formulate the engineering analysis to exhibit a substantially equivalent understanding of the condition of the pipeline will be provided using the alternative method. The notification will likely extend to a substantial amount of the (+-) 4000 miles of gathering, not the ten requests PHMSA has projected it will receive.

Within the RIA, PHMSA included the following discussion and sought comment.

> *Neither the estimate for ILI testing nor the estimate for the pressure testing includes the loss of throughput during the 6 to 10 days that the pipeline is shut down for testing. The lost revenue during this time can be a significant cost to the operator, but the loss to the operator performing the test is a gain to other operators who may move the throughput*

[4] Pipeline Safety: Protecting Unusually Sensitive Areas From Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines, FR June 3, 2008 (Volume 73, Number 107)

> *instead. From a cost-benefit perspective, there is no net social loss from the loss of throughput for an individual operator, provided that the liquid will be rerouted through other pipeline. If, however, the temporary closure of a pipeline for pressure testing results in a bottleneck that significantly delays the delivery of HL product to end users, then the cost delays caused by lost throughput could be a significant cost associated with pressure testing. PHMSA seeks comment on the cost of pressure testing in general and the cost of lost throughput specifically.*

PHMSA misstates the impact to gathering operators by comparing gathering pipeline operations to the intrastate and interstate pipeline grids. Gathering pipelines are designed hydraulically to move production from specific formations. A typical gathering system is dedicated to an individual operator and is not always connected to other gathering pipelines. Therefore, moving product on another operator's dedicated gathering system is not a readily available option without months of commercial planning and negotiating, possibly requiring installation of additional pipeline, all of, which is cost prohibitive. If a commercial solution is not available, shutting in a gathering line would negatively result in production shut-ins, possibly damaging the formation and forever lost production.

All gathering throughput will either cease or incur trucking costs as there is seldom an alternate pipeline route available. The cost for smaller diameter is not half as PHMSA has assumed. Much of the cost of the actual test is labor and equipment, not purchasing water. As API-AOPL noted in their response to the ANPRM, operators of crude oil gathering systems continually assess the economic viability of their gathering lines. Imposing further regulatory compliance activities with little or no realized benefit may well result in transportation turned over to trucking organizations. The crude oil is thus moved from a safe and unobtrusive mode of transportation located underground (pipeline) to one with many more hazards located on public highways and roads and contribute to increased greenhouse gas emissions from commercial trucks.

In the proposal to collect data on unregulated gathering lines, PHMSA stated the objective is seeking to obtain data to make informed decisions regarding rulemaking. A review of PHMSA accident data[5] from 2010 to current reveal that 87 of the 2256 reported accidents occurred on gathering lines. This equates to 3.8% of the accidents reported. Of these, 45 occurred on gathering lines reported to have MOP's established at a pressure =<20% SMYS, which implies they are in a non-rural location and are likely subject to the Integrity Management Programs prescribed in § 195.452. Thus, it would appear that the proposal is targeted at pipelines which, at most, have caused 1.9% of the reportable accidents in the last five years.

Therefore, GPA urges PHMSA to remove this provision from the final rule, implement the data collection component, and use the data collected to make fact-based, risk-based decisions in the future.

Leak Detection on Gathering

[5] http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

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PHMSA is proposing to require the installation and maintenance of leak detection systems on all liquids pipelines. In its proposal, PHMSA has stated "*The use of such systems will help to mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs.*" In Section 5 of the ACT, congress directed PHMSA to study and report on leak detection and within the study include, "…*an analysis of the technical limitations and the practicability, safety benefits, and adverse consequence of establishing additional standards.*" Kiefner and Associates, Inc. completed the required study on leak detection systems used by all types of pipeline transportation. That study, titled "Leak Detection Study"[6], evaluated leak detection systems on gas transmission, gas distribution, and hazardous liquids systems.

The Kiefner study covered 30 months from 2010 – 2012. Within the study period, liquid transmission pipelines experienced 197 accidents with five fires with two exploding and one of those resulting in a public fatality. The largest volume spilled was 843,444 gallons with the second largest at 556,122 gallons and the smallest 0.42 gallons.

During the same time period there were 22 reportable releases from gathering lines. The largest release from a gathering line was 8400 gallons. The smallest was 10 gallons. None of the 22 resulted in ignition or explosion. For the releases associated with the gathering lines, SCADA was reported as functional in 5 of the 22 reported incidents. Of the five accidents where SCADA was functioning, only one (1) of the incident reports indicated that SCADA assisted in the detection of the incident. Thus, SCADA was effective in aiding detection only 20% of the incidents reported.

The North Dakota legislature passed House Bill No. 1358, which was signed by Governor Dalrymple in April 2015. One provision of the bill required the North Dakota Industrial Commission (NDIC) to contract with the Energy and Environmental Research Center (EERC) at the University of North Dakota to *"…determine the feasibility and cost effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems."* That study, "Liquids Gathering Pipelines: A Comprehensive Analysis"[7], was delivered to the NDIC and the Energy Development and Transmission Committee on December 1, 2015. The leak detection portion of the research was focused on leak detection capabilities and limitations for crude and produced water gathering systems exclusively. The study generated several "key findings" that are related to PHMSA's proposal. The following quotes from within the body of the report directly illustrate why PHMSA's proposal is not appropriate for gathering lines at this time:

- *It should be emphasized that gathering lines present unique challenges to leak detection technologies. As a result, some care must be taken when extrapolating transmission line experience to gathering lines.*

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6 http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak%20Detection%20Study.pdf

7 http://undeerc.org/Bakken/Pipeline-Study.aspx

- *Gathering line systems are constantly transitioning in flow, pressure, and line-packing. Unlike transmission pipelines with very few branches, gathering systems have tens to hundreds of pipeline connections. These and other differences between transmission pipelines and gathering lines create greater challenges for designing, installing, and operating internal leak detection on gathering lines than transmission pipelines.*

- *Company decisions regarding implementing new pipeline monitoring and leak detection technology rely upon, among other things, analysis of the cost and benefit. There is a need for objective data on the performance of different leak detection technologies under real-world conditions.*

- *The better defined the operational conditions are, the more sensitive the leak detection method that can be applied. Low-pressure operation is common, and multiple flow inlets and very few outlets lead to significant flow variation as pumps cycle on and off or wells begin or cease production. The very nature of oil production leads to fluctuations that are not easily reduced or eliminated.*

- *At this time, no technology has demonstrated undisputed reliability in detecting spills on interstate pipelines, much less on more problematic gathering lines.*

Consistent with the recommendations for assessments on gathering, GPA urges PHMSA to remove this provision from the final rule, implement the data collection component, and use the data collected to make fact-based, risk-based decisions in the future.

C. Gravity lines

Extension of the Reporting Requirements

In response to the ANPRM, API-AOPL provided PHMSA with comments identifying the fact that 3 of their member companies operate a total of 17 miles of gravity lines. As PHMSA points out, gravity lines may also exist in tank farms. PHMSA has estimated that, at most, five hazardous liquid pipeline operators will be affected. At least three GPA members have responded expressing concern with the ability to gather all of the data required to comply with the data collection effort as proposed without extensive resource commitment. All would involve piping at tank farms.

The majority of GPA responding members support the data collection efforts with essentially the same comments and concerns expressed above for gathering lines. We recommend an abbreviated form as described above for this purpose as well.

D. Leak Detection (non-gathering)

As discussed above for gathering lines, PHMSA has proposed a requirement to require leak detection and computational pipeline monitoring ("CPM") for those segments outside of (HCA's). Unlike applying the proposed requirements to gathering systems, GPA generally supports the proposal for remaining pipelines.

In the proposed §195.134(b), PHMSA has pointed to the requirements in § 195.444. In the proposed §195.134(c), PHMSA has explicitly cited Section 4.2 of API 1130 for new or replaced systems or components. It would provide further clarity if PHMSA would provide the specific citations in API 1130 it expects operators to follow, such as Section 6.5 for CPM training.

PHMSA did not include any discussions or proposal for expected compliance timeframes or retroactive application. The current requirements in §195.444 are applicable to those CPM systems in place. The proposal appears to require installation of leak detection indiscriminate of the time the pipeline was installed. No assumed costs have been provided for those systems which do not already have something in place. Compliance timing for the proposed training component are absent also. Implementation timeframes should be longer for systems that have no leak detection currently in place versus those which need minor modifications and those which fall somewhere between. Likewise, there may be programs in place as sub-components of Control Room Management training which satisfy the requirements, but an evaluation may still be necessary for validation purposes. And there may be impacted operators which do not currently have control rooms or the CPM functions outside of the control rooms and may require development and implementation from the ground up. PHMSA has not included any estimates of expected costs for the training component of this proposal.

GPA urges PHMSA to establish a seven (7) year installation and implementation timeframe. This should provide time to conduct system evaluation for use in leak detection system design, procurement, installation, testing, and training. The GPA urges PHMSA to provide relief for short sections less than one (1) mile in length and those that are located within facilities where they pose no risk to the public. Dedicating resources without likely benefit provides value to no one. It would also provide continued consistency with the exceptions provided in §195.120 and the recommendations GPA is submitting for the ILI assessments proposal.

E. <u>Post Disaster Investigations</u>

GPA supports what it believes to be the spirit of the proposal as published by PHMSA. However, PHMSA's expectations for operator actions under the "weather related" inspection are not clear. To begin with, a "weather related" event can have dramatically different effects based on the type of event. Is this expectation to use NOAA 10 year, 50 year, or 100 year data for flood conditions? Areas, such as Oklahoma, have experienced hundreds of earthquakes over the last two or three years. Yet, most are in the 2.0 Richter range. Hurricanes may range from Category 1 to Category 5 and as PHMSA is aware, can have dramatically different consequences. PHMSA must either define exactly which events require response and inspection or establish performance expectations without partially defining the criteria.

PHMSA should define cessation as "the point in time when the operator determines no further threats to personnel safety or equipment exists" as the time when evaluation activities may proceed.

PHMSA has proposed the inspection occur within seventy-two (72) hours after cessation of the event. Does this mean that PHMSA expects the inspection to be started, in-progress, or completed? In large scale events, such as Hurricane Rita and flooding of the San Jacinto River, there may not be resources available, such as generators or ILI tools for all operators to accomplish the goals PHMSA is proposing.

As an alternative to creation of a completely new regulatory section, PHMSA could modify the section requiring Emergency Plans (§ 195.402(e)) to require an inspection following events to determine if an emergency situation has developed and, if so, the provisions in the operator's emergency plan should be implemented. This would be a less ambiguous way to achieve the desired goal.

We propose PHMSA amend § 195.402(e) to read as follows;

(e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs;

(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

(i) The notices of events must include extreme weather events which may impair the serviceability of the operator's pipelines in the area and the operator must inspect all potentially affected pipeline facilities as soon as the operator determines no further threats to personnel safety or equipment exists.

(ii) An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under paragraph (i) of this section.

F. Non-Integrity Management Segment Provisions (not gathering)

Assessments and Notifications

PHMSA is proposing to require assessments for pipeline segments in non-HCAs. Specifically, the proposed § 195.416 would require operators to assess non-HCA (non-IM) pipeline segments with an ILI tool at least once every 10 years. PHMSA has further stated that other assessment methods could be used if an operator provides the Office of Pipeline Safety (OPS) with prior written notice that a pipeline is not capable of accommodating an ILI tool. The written notice provided to PHMSA must include a technical demonstration of why the pipeline is not capable of accommodating an ILI tool and what alternative technology the operator proposes to use. The operator must also detail how the alternative technology would provide a substantially equivalent understanding of the pipeline's condition in light of the threats that could affect its safe operation. Such alternative technologies would include Hydro Testing or appropriate forms of direct assessment.

GPA questions why PHMSA has not taken the more reasonable approach as it is proposing in the modifications to § 195.452(c)(1)(i)? PHMSA and its state partners would still be able to evaluate the reasons an ILI was not used, but without the burden, on both regulators and industry and the delay created by the notification process.

In the RIA, PHMSA has assumed a cost of $5150 per mile to assess using ILI, including costs for pipeline cleaning, labor, and contractor selection and oversight. While GPA could not obtain 2015 dollars within the comment period window, we believe this is underestimated.

In the RIA, PHMSA assumed that new construction pipelines would not incur any assessment costs in the first ten years since they would be Hydro Tested post construction. However, as written, PHMSA is proposing to require prior notification to use any assessment method other than ILI. Through literal interpretation of the proposal, an operator would submit prior notice during the construction of a pipeline that it plans to use the post construction Hydro Test as a "qualifying assessment" as well. Is this the process PHMSA envisions for an operator to be compliant without conducting duplicative tests? Currently, we see no recognition of this test as sufficing for an assessment without notification within the proposed rule. GPA would like PHMSA to provide clarification on this issue.

If this is not the case and PHMSA recognizes a post construction Hydro Test as a valid assessment method for revealing harmful defects, then the same recognition should be afforded those used as regular assessments without a prior notification.

PHMSA did not include any expectations for implementation timeframes in the proposal. Is there a percentage per time period anticipated, i.e. 50% each five years or is PHMSA willing to provide operators scheduling flexibility to weave it into other compliance activities? For example, if an operator is running an ILI on Pipeline A as a 5 year reassessment for IM purposes, they may have the ability to conduct an assessment on Pipeline B in the same general geographic area and possibly minimizing or eliminate some mobilization costs and maximize use of resources.

GPA requests PHMSA provide exceptions for short lines, e.g. less than 1 mile in length, that are contained within the operators facilities and pose no risk to the public. This would keep it consistent with the exceptions contained, currently and in the proposed modified §195.120(b).

GPA would also like to know if PHMSA considers deferring assessments on Out-of-Service Idle (product evacuated, nitrogen blanketed) lines until preparation for return to service acceptable under this proposal? Under these conditions, there is no risk from a release. This would be consistent with policy established during implementation of the Integrity Management Program.

Data Analysis

PHMSA is proposing to include performance language requiring persons performing the data analysis of non-IM assessments to be "qualified by knowledge, training, and experience." API-AOPL and many other commenters responding to questions posed in the ANPRM supported the incorporation by reference of American Society of Nondestructive Testing (ASNT) ILI PQ to satisfy the need to assure quality data analysis. In this preamble, PHMSA has stated "*PHMSA is proposing by a separate rulemaking via incorporation by reference available industry consensus standards for performing assessments of pipelines using ILI tools, internal corrosion direct assessment, and stress corrosion cracking direct assessment.*"

We encourage PHMSA to include ASNT ILI PQ as part of that rulemaking while deferring action on the current proposal. Operators typically do not have the expertise to judge vendors on their proprietary technologies.

Non-IM Remediation

PHMSA is proposing to establish essentially the same repair criteria as for those segments which could affect a HCA without identifying why it is believed this is a necessary step. Has PHMSA documented through its enforcement program that the current requirements in §195.401(b)(1) are unenforceable as written?

At a minimum, PHMSA should revise the "18 month" timeframe to read two years to allow for scheduling around unfavorable weather conditions which can be detrimental to the repair process and to enable them to be included in budget processes.

G. Integrity Management Assessments

Required Use of ILI

Changes proposed for §1955.452(c)(1)(i) to require use of ILI unless it is impracticable seems to be a reasonable approach and encourages use of ILI, but does not penalize the operator by requiring notifications. It allows for the continued use of other methods which may be more appropriate for threats such as Low Frequency Electric Resistance Welded pipe.

As stated above, we urge PHMSA to adopt the same approach for non-gathering, non-IM assessments proposed in §195.416.

Information Analysis

GPA does not believe PHMSA's proposal as written (§ 195.452(g)), is necessary. It is duplicative of much of the material contained in Appendix C, PHMSA's Enforcement Guidance documents, and API RP 1160. If PHMSA has experienced failure of operators to consider these factors, it would appear this is an enforcement issue not a reason to create more regulation. The expectations have been clearly communicated throughout implementation of the integrity management programs.

Modifications to Accommodate ILI

GPA believes it would be reasonable to implement this element for pipelines in HCA's. For the reasons discussed in the "Performing Assessments on Gathering" section above, applying this requirement to gathering and short lines will likely result in money spent for retrofitting, but resulting in pipelines which will still not be "piggable" because of flow characteristics. Thus, spending the required capital without obtaining the desired results of being "piggable" could render many gathering systems uneconomical to continue operating moving them back to reliance on trucking.

GPA appreciates the opportunity to comment on the notice and request for comments regarding *"Pipeline Safety: Safety of Hazardous Liquid Pipelines"* published by PHMSA in the October 13, 2015 Federal Register. GPA has provided comments and recommendations that will create a practical path forward to meet the continued need to achieve US energy independence while ensuring the infrastructure used to transport it continues to do so in a safe, economical manner. Please contact me at (202)279-1664 or mhite@gpaglobal.org if GPA can be of assistance.

Sincerely,

Matthew Hite
Vice President of Government Affairs
Gas Processors Association