UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Five-Year Review of Oil Pipeline Pricing Index  )  Docket No. RM10-25-000

DECLARATION OF WILLIAM R. BYRD
ON BEHALF OF THE ASSOCIATION OF OIL PIPE LINES

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I. Introduction

My name is William R. Byrd, PE. I am a professional engineer and regulatory expert, with significant experience in the pipeline industry as both a manager and consultant, as described in my Curriculum Vitae (attached). I am the founder and President of RCP Inc., a consulting firm that provides professional engineering capabilities and regulatory expertise to energy and energy-related companies. Pipeline operations, regulation and compliance are particular specialties of mine.

I have been retained by the Association of Oil Pipe Lines (“AOPL”) to render my professional opinion concerning regulatory trends and their cost implications for liquid pipelines operating in the U.S. The purpose of this declaration is to provide my opinion on whether the cost changes calculated by AOPL’s economic expert, Dr. Ramsey Shehadeh of NERA Economic Consulting, are consistent with real-world industry experience and my knowledge of the liquid pipeline industry. In conducting this analysis, I have reviewed and analyzed the regulatory requirements applicable to oil pipelines and their impacts on pipeline costs.

As discussed below, this declaration contains my expert opinion that Dr. Shehadeh’s analysis of pipeline cost changes is consistent with the regulatory trends that oil pipelines have experienced in recent years, which have resulted in significant cost increases for oil pipeline operators. In my opinion, these same regulations, as well as additional new and anticipated regulations, will likely cause oil pipeline costs to continue to increase at a similar or greater rate in the future. Any rate index established by the Commission should reflect this reality.

II. Qualifications

I am a Summa Cum Laude graduate of the Georgia Institute of Technology, receiving my BS in Mechanical Engineering in 1981, and my MS in Mechanical Engineering in 1982, having received a Fellowship from Georgia Power for my graduate work and thesis. Upon graduation, I worked for Exxon’s production department in various capacities as an engineer, engineering supervisor, Regulatory Compliance Manager, and Gas Coordination Manager, before becoming Area Manager for Exxon Pipeline Company in 1993.

As Regulatory Compliance manager for Exxon’s eastern U.S. production division, I was responsible for all manner of regulatory compliance issues, including pipeline safety. As Area Manager for Exxon Pipeline, I was responsible for a broad range of operational and safety issues for liquid pipelines, including regulatory compliance. I also led a team that was responsible for “re-engineering” the maintenance programs for Exxon Pipeline, leading to a complete reorganization of the company. That initiative required me and my team to evaluate all the maintenance expenditures for the company in order to identify areas for improvement.

Using the expertise I gained from my educational background and experiences at Exxon, I established RCP in 1995 to provide consulting services to the energy pipeline industry. RCP has grown steadily in the past 15 years, and now has 45 employees and over 100 clients – most of
whom operate regulated gas or liquid pipelines. Our consulting services include regulatory compliance, risk management, compliance management, and compliance program development.

I frequently speak at industry meetings and seminars on pipeline safety topics, and am frequently published in industry journals and publications, as listed in my CV, attached hereto. I edit the DOT Pipeline Compliance Newsletter, which is distributed to more than 6,000 professionals in the pipeline safety community each month. I am on the executive committee of the Safety Engineering and Risk Analysis Division (SERAD) of ASME (American Society of Mechanical Engineers), an engineering society that is recognized worldwide and whose standards are incorporated into regulations by countless federal, state, and local jurisdictions. I am also the Chair for the Safety Engineering, Risk Assessment, and Reliability Methods track at the International Mechanical Engineering Congress and Exhibition (IMECE), attended by thousands of engineering and risk management professionals from around the world.

My background and experience qualify me to render an expert opinion concerning the issues contained in this declaration.

III. Key Regulatory Obligations and Corresponding Costs: 2004 - 2009

In this section, I discuss the principal regulatory requirements affecting oil pipeline costs during the period 2004 through 2009, with a particular emphasis on pipeline safety regulation. As I explain, compliance with these regulatory mandates leads oil pipelines to incur significant expenditures. As recent events have shown, ensuring the integrity of our nation’s energy infrastructure is crucial to the well being of our environment and public safety. It is therefore essential that the oil pipeline rate index be set at a level that allows recovery of the costs needed to comply with these important regulatory requirements.

Hazardous liquid pipelines in the U.S. are regulated by the Department of Transportation, Pipelines and Hazardous Materials Safety Administration’s Office of Pipeline Safety (PHMSA), or by state agencies delegated powers by PHMSA with respect to intra-state pipelines. By law, state regulations must be at least as strict as the federal regulations. This declaration only addresses the federal regulations, but it should be recognized that individual state regulations may exceed federal requirements and result in additional expenditures. The major federal regulatory mandates that have led to significant expenditures for oil pipelines during the period 2004 through 2009 are described below.

Integrity Management Regulations

The most significant regulatory development for hazardous liquid pipeline operators in recent years has been the promulgation of PHMSA’s Integrity Management Program (IMP)

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1 Hazardous liquid pipelines include pipelines that carry crude oil and refined products, such as gasoline, diesel fuel, jet fuel, etc. See 49 CFR § 195.2.
2 State agency programs must be certified pursuant to 49 U.S.C. § 60105.
regulations.\textsuperscript{3} These regulations were originally promulgated in December 2000, and have been amended several times since then. The regulations apply to all parts of a pipeline that could affect a “high consequence area” (HCA).\textsuperscript{4} I will refer to those portions of the pipeline as “HCA pipe.” The rule requires that operators:

1. develop a written integrity management program that addresses the risks associated with HCA pipe,
2. identify the portions of their pipeline system that are considered HCA pipe and rank these according to risk,
3. carry out baseline assessments of the HCA pipe, in risk order,
4. investigate anomalies and remediate defects discovered during the inspections,
5. identify additional preventative and mitigative measures to protect HCAs and reduce risk, and
6. measure the integrity management program’s effectiveness and continually improve the program, while conducting reassessments for the life of the pipeline system.\textsuperscript{5}

I will address each of these requirements in turn. Although pipelines incur significant internal costs for integrity management, such as for salaries and wages and materials and supplies, in my experience the great majority of expenditures related to this rulemaking are for outside service providers. As described further below, the increased costs related to IMP compliance caused outside services costs to increase substantially during the 2004 through 2009 period.

The written integrity management program must be developed before any other activities can be performed, since the program describes how those activities are to be performed, and the activities must follow the written plan. Development of the written integrity management programs required by the regulations is not a trivial exercise. PHMSA’s requirements for these written programs are exacting and extensive. The PHMSA audit protocols for hazardous liquid pipeline integrity management programs currently are 121 pages long, covering topics such as segment identification, remedial action, risk analysis, preventive and mitigative measures, and the “continual process of evaluation and assessment.”\textsuperscript{6} The PHMSA website also includes over 200 “frequently asked questions” related to hazardous liquid pipeline IMP programs, organized under 13 different topic headings.\textsuperscript{7} Most operators rely on specialized outside consultants to assist them with development of the required documentation, which adds to their outside services costs.

Once operators have developed their written programs, they are required to identify the portions of their pipeline system that “could affect” HCAs. The process of identifying these portions of

\textsuperscript{3} See 49 CFR § 195.452.
\textsuperscript{4} The full definition of an HCA can be found at 49 CFR § 195.450. An HCA includes (1) “a commercially navigable waterway,” (2) any “high population area” or “other populated area,” or (3) “an unusually sensitive area,” which includes sources of drinking water and ecologically sensitive areas. See 49 CFR §§ 195.450 and 195.6. For most parts of the U.S., PHMSA identified the HCAs. In other areas, the operators themselves were required to identify HCAs.
\textsuperscript{5} See 49 CFR § 195.452.
\textsuperscript{6} http://primis.phmsa.dot.gov/iim/docsp/Updated_HazLiquidIMProtocolForm_122007.pdf
\textsuperscript{7} http://primis.phmsa.dot.gov/iim/faqs.htm
pipe is complex and requires sophisticated geospatial modeling and the use of geographic information systems (GIS). These GIS systems must incorporate a huge amount of information about the pipeline itself and the terrain and other features around the pipeline. Spill models must be developed to determine how much fluid might be released from any given location on the pipeline system. Theoretical spills are then modeled to see how they would flow across the surrounding area (e.g., considering elevation changes, nearby waterways, fluid retention in various soil types) to determine if they could eventually affect an HCA. This type of analysis must be conducted for the entire length of every pipeline segment. The HCA pipe is then analyzed for the risk it poses to the affected HCAs, and all of the operator’s HCA pipe is ranked according to risk. This risk-ranking is used to determine the baseline assessment schedule, so that the portions of the pipeline system presenting the highest risk are assessed earlier in the program. Most operators require specialized outside consultants to develop these systems for them and to conduct the necessary analyses to determine HCA pipe. The costs for these outside consultants are reflected in the pipeline’s outside services expenses. Many operators also invest directly in expensive computer systems and software in order to support these programs on an ongoing basis.

After developing the initial integrity management program and identifying and risk-ranking the HCA pipe, operators are required to perform a baseline assessment of the HCA pipe for all of the identified threats to their integrity. The great majority of pipeline integrity assessments are conducted by either in-line inspection (ILI) tools (also known as “smart pigs”) or hydrostatic pressure testing, as detailed in the IMP regulations.\(^8\)

ILI is the most common assessment method. ILI tools are essentially self-contained inspection systems including computers, battery packs, and a host of sensors of various types. These tools can be more than twenty feet long and weigh more than a thousand pounds. They are inserted into the pipeline via “pig traps” and travel down the length of the line to gather data concerning any defects. Because the tools used to conduct these tests are quite expensive and the tools become outdated as technological innovation allows for improvement and updating, liquid pipelines do not themselves own the tools used to conduct integrity assessments. Instead, pipeline operators contract with third-party vendors to perform the assessments and analyze the data, while using pipeline personnel to oversee the project.

Pipeline operators use different types of smart pigs depending upon the threats to the integrity of the pipeline segment in question. All line segments are generally considered at risk for corrosion as well as for deformation (e.g., dents and gouges caused by contact with construction equipment). Certain types of smart pigs (e.g., Magnetic Flux Leakage tools) are generally used to identify corrosion, while other types of pigs (known as geometry tools) are most often used to identify deformation. Where a particular segment is found to be at risk of additional threats to its integrity, such as cracking, additional assessments must be done using more specialized smart pigs or hydrostatic testing.

\(^8\) 49 CFR § 195.300-310.
ILI assessments typically require extensive preparation and logistical support. Most operators have incurred significant costs to modify pipeline systems to accept ILI tools. Permanent or temporary modifications of the pipeline may be required to allow the ILI tool to be inserted into and removed from the pipeline and to allow the tool to pass through intermediate valves and connections with other pipelines. As noted, ILI tools can be very long, and even pipelines that have permanent pig launching and receiving facilities may need to modify their facilities to insert the ILI tools into the pipeline and remove them at the other end. In addition, the line must be cleaned in order to obtain a reliable ILI assessment. The cleaning process itself can take weeks, especially for crude oil pipelines. Indeed, while renting the tools and analyzing the data are expensive, the cost of preparing the line to accept the ILI tools can easily exceed the cost of conducting the actual inspection. Because conducting an ILI must be done under specific operating conditions, a great deal of time, effort and resources is also expended on sequencing and scheduling assessments and follow-up work after the inspections.

Even after all of the appropriate precautions have been taken, it is not uncommon to have a failed ILI for various reasons, including equipment failure in the tool itself, which requires another inspection. ILI tools can also become stuck in the pipeline, inevitably at the most difficult location to access, requiring that the line be shut down and cut apart. All of this can greatly increase the cost of the inspection.

ILI costs generally range from $1,000 to $15,000 per mile, although the total inspection cost is not directly proportional to the length of the pipeline segment, since the mobilization costs to deploy the ILI tool and crew to the site are independent of the line length, and preparing the line for inspection can cost as much or more than the actual tool run. The total cost to conduct a typical ILI to detect normal corrosion or deformation on a single pipeline segment is about $200,000. The costs can increase dramatically, however, if the pipeline must be modified to accept the ILI tools or if additional specialized tools are needed. For example, the cost to assess a single segment of pipe for the presence of stress corrosion cracking (SCC) using a specialized in-line inspection tool can be over $1 million, because SCC tools are longer and more sophisticated than metal loss ILI tools. They also require a higher level of cleanliness of the line and must be run at lower velocities. Regardless of the type of smart pig used, in-line assessment is an expensive and time-consuming process.

Once the pig run has been completed, the data received is typically sent to an outside vendor for analysis. Analysis of the data, which can be time-consuming and expensive, identifies “anomalies” detected by the tool. These inspection anomalies may or may not represent actual defects in the pipeline. Proper follow-up on the results of the analysis often requires excavation of identified anomalies and manual inspection by trained personnel to properly identify any defects. Other excavations and manual inspections are also frequently performed in order to calibrate the ILI tool, to ensure it is giving reliable information. All of these excavations and inspections are expensive and are required even if no actual pipeline defect is found. Of course, any significant defects require further remediation, possibly including replacement of part of the pipe.
Another acceptable assessment technology is hydrostatic testing. Hydrostatic testing requires that the pipeline segment be taken out of service for several days while the product is displaced and water is injected into the line. After the line is filled with water, the line is pressurized to a level significantly higher than normal operating pressure in order to detect any defects that might fail at or below the test pressure. If there is a failure, the defect must be found and repaired. Often, these defects can be very difficult to locate, since they may involve only small seeps from the line. After the defect is located and fixed, the line is then re-pressurized and the process repeated until the pipeline is able to hold the required pressure. After a successful test, the water must be removed and properly disposed of. Water disposal can be the most difficult and expensive part of a hydrostatic test. Hydrostatic assessment costs are generally higher than assessment costs using a typical smart pig.

The IMP rules required that “baseline” assessments be conducted for HCA pipe within seven years of the effective date of the rule. Subsequent assessments are generally required on five-year intervals after the baseline assessment, and these assessments continue for the life of the pipeline system. Pipeline operators, however, are required to base the reassessment intervals on the specific characteristics of each line segment. Thus, where certain pipeline integrity issues may be expected to develop more rapidly than normal, a pipeline operator may be required to re-assess on a more frequent basis.

The IMP regulations not only require ongoing periodic assessments of HCA pipe, they also require that “preventive and mitigative measures” be taken to reduce the risk posed by these pipes. Preventive and mitigative measures must be customized for each segment of HCA pipe, depending on the associated integrity threats or risk factors. Such measures could include more frequent line patrols and surveillance, a more robust corrosion control program, or other similar activities. While it is difficult to quantify the total cost incurred by pipeline operators related to such preventative and mitigative measures, it is clear that additional spending has been required to meet this requirement.

Lastly, operators are required to measure the integrity management program’s effectiveness, and continually improve the program over time. Liquid pipelines have an ongoing regulatory requirement to conduct integrity assessments and to “continually change the program to reflect operating experience.” Simply stated, last year’s actions will not be sufficient this year, and this year’s actions will not be sufficient next year. Constant changes and improvements are required by the regulation. Costs are therefore likely to increase.

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9 See 49 CFR § 195.452. For large operators (operating more than 500 miles of liquid pipelines), the IMP regulations became effective on March 31, 2001, and all baseline assessments were required to be complete by March 31, 2008. For small operators, the IMP regulations became effective on February 15, 2002, and all baseline assessments were required to be complete by February 15, 2009. Id. Due to the need to write the IMP program documents and conduct the sophisticated modeling required to determine HCA pipe, the bulk of the baseline assessments occurred during the 2004 through 2009 period.

10 See 49 CFR § 195.452(j)(3).

11 Id.

12 49 CFR § 195.452(f).
Nationwide, approximately 50 percent of hazardous liquid pipeline mileage is classified as HCA pipe. From a practical standpoint, however, significantly more than 50 percent of the liquid pipeline mileage has been assessed under the IMP rules, since most assessments are conducted for an entire pipeline segment, not just the portions that are officially considered HCA pipe. It is impractical to conduct an in-line inspection for only part of a pipeline segment. The entire segment is inspected by the ILI tool, since the pig traps are installed at each end of the segment. Likewise, a hydrostatic test would be conducted for an entire pipeline segment – or at least for the entire amount of pipe between isolation valves – not just the part of the pipe that was considered to be HCA pipe.

Compliance with the integrity management regulations is likely to be the largest single variable cost item for most pipelines and these costs show no signs of decreasing. For example, during the prior indexing review, the U.S. Department of Transportation (“DOT”) indicated that the baseline assessments “would cost operators more than $120 million over seven years …; retesting, $14.5 million annually; preparation of integrity plans, almost $18 million; and related implementation costs …, almost $10 million the first year and almost $5 million annually thereafter.”¹³ In fact, costs have vastly exceeded those estimates. Indeed, in an informal AOPL member survey, pipelines accounting for approximately three-quarters of DOT-jurisdictional hazardous liquid pipeline miles estimated that their integrity management costs (including both capital and expense) were approximately $2.7 billion for the years 2004 through 2009. Those costs relate only to pipeline integrity management. Integrity management costs related to tankage owned by the same group of pipelines were estimated to have been approximately $600 million for both capital and expense during the period 2004 through 2009. Thus, the combined amount of capital costs and operating expenses incurred with respect to pipeline and tankage integrity during the 2004-2009 period for those pipelines alone was estimated at approximately $3.3 billion.

One measure of the dramatic surge in oil pipeline costs related to integrity management is the increase in outside services expenses. As explained above, most pipeline assessment costs involve rental of smart pigs and hiring vendors to conduct the assessment and perform the required data analysis. As Dr. Shehadeh notes in his declaration, the median change in the operating and maintenance portion of outside services costs recorded in FERC Form 6 increased by a cumulative 69.3 percent for oil pipelines between 2004 and 2009.¹⁴ Thus, while outside services expenses are not the only costs related to IMP compliance, and while not all outside services expenses are related to pipeline integrity, the significant increase in this single cost category illustrates the increasing cost pressures oil pipelines face with respect to integrity management compliance.

In sum, given the high cost of assessments, the ongoing requirement to do so, and the ever-increasing standards of performance built into the regulations, compliance with the IMP regulations is clearly a very expensive undertaking for the industry, whether ILI or hydrostatic testing is used, and will continue to be for the foreseeable future.

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¹⁴ Shehadeh Decl. at 12.
Future IMP Costs

Clearly, the oil pipeline industry incurred substantial costs related to the IMP regulations during the 2004-2009 period. In my view, there are several reasons why these costs are likely to increase in future years.

First, technological innovation continues to improve the sensitivity and capability of ILI tools. Smart pigs are getting smarter, which means that more advanced ILI tools are able to locate pipeline integrity issues that were not identifiable previously. For example, advanced smart pigs are able to better detect pipeline cracking. Although this furthers the public interest by allowing pipelines to remedy potential safety hazards before failure, it does not tend to reduce costs. On the contrary, as tools become more sophisticated and specialized, they generally become more expensive. Also, the more sophisticated the tool, the more anomalies it detects. Identification of anomalies generally requires excavation, manual testing and additional data analysis, even though the great majority of anomalies often do not represent a significant pipe defect. Of course, if upon inspection the identified anomalies turn out to be actual defects that must be remediated, the additional remedial actions, such as digs and repair work, also add substantial costs.

Second, I anticipate that PHMSA’s requirements will continue to increase and that pipeline operators will increasingly spend more time and money to meet those requirements. As mentioned above, new tools are being developed that are able to detect specific types of pipeline defects. PHMSA will require operators to use the new technologies as they become available, even though the cost of those inspections (using newer tools with newer technology) will be higher than the previous inspections. It is important to note that cost is not considered by PHMSA to be a relevant factor when selecting assessment technology for HCA pipe. Instead, the assessment methods selected must be able to address all of the integrity threats for the pipeline, regardless of the cost of the assessment methods. As new technologies are developed, their use will be required as applicable, regardless of cost. I expect these trends to continue for the foreseeable future as the inspection technology matures.

Third, new or expanded regulatory requirements could be imposed as the U.S. Congress considers reauthorization of the Pipeline Safety Act, which is expected to occur later this year or in 2011. Several issues are being considered by Congress. The most prominent of these, in terms of potential increases in pipeline costs, is the possible expansion of integrity management regulations beyond the current HCAs. As discussed previously, PHMSA regulations require special pipeline integrity management programs for HCA pipe, and approximately half of the hazardous liquid pipeline mileage is currently considered to affect HCAs. As part of the Pipeline Safety Act reauthorization process, Congressional committees have convened oversight hearings and sought input from PHMSA, interest groups and industry. During this process, proposals have been made to expand the integrity management regulations to include even more pipeline mileage, by expanding the definition of HCAs and/or changing how the impacts to HCAs are
calculated.\footnote{See Comments of the Pipeline Safety Trust, submitted in response to the House Transportation and Infrastructure Committee Hearing on Implementation of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Reauthorization of the Pipeline Safety Program, May 20, 2010, page 4 (http://transportation.house.gov/Files/052010/19900520/Weimer.pdf). It should also be recognized that PHMSA has authority to promulgate regulations to extend the requirements of the IMP Program beyond HCAs.} If enacted, this would, at a minimum, require additional planning expenditures, inspections, mitigation actions and remediation activities for any pipeline segment that fell under the new regulations. Depending on the nature of any such new regulatory requirements, the additional cost burden for oil pipelines could be substantial.

Fourth, recent events in the Gulf of Mexico could very well lead to significant additional integrity regulation. The Deepwater Horizon oil spill has dramatically increased public concern with the safety of our nation’s energy infrastructure. In the aftermath of this event, policymakers and regulators are redoubling oversight efforts, which could result in more stringent PHMSA regulation of liquid pipelines. For example, PHMSA’s regulations require liquid pipelines to have spill response plans that identify areas at risk, develop response strategies, identify and secure response resources, and conduct routine drills.\footnote{Recently, PHMSA issued an Advisory Bulletin reminding pipeline operators that in light of the Deepwater Horizon oil spill in the Gulf of Mexico, which resulted in the relocation of oil spill response resources to address that incident, they have a responsibility to review and update their oil spill response plans and to comply with other emergency response requirements to ensure the necessary response to a worst case discharge from their pipeline facility. See “Pipeline Safety: Updating Facility Response Plans in Light of the Deepwater Horizon Oil Spill,” 75 FR 36773 (June 28, 2010).} Legislation could very well be enacted, affecting entities such as pipelines that maintain oil spill response plans, requiring procurement of additional spill response equipment, additional manpower and training, increased drills and coordination with local emergency response officials, and supplemental contract resources. In my opinion, the reaction to the Deepwater Horizon event by both the public and regulators may lead to significantly greater regulatory burdens and expense for the liquid pipeline industry.

In summary, the regulatory compliance requirements imposed on the liquid pipeline industry related to safety and integrity have been significant. While these requirements have clearly produced substantial societal benefits, they have also led to markedly increased costs. In order to achieve the important goals of these safety and integrity regulations, it is essential that the oil pipeline rate index be set at a level that allows for the recovery of the corresponding compliance costs.

\textbf{Other Regulatory Obligations}

The integrity management regulations described above have been a primary cause of increased oil pipeline costs in recent years, especially outside services. Other regulatory compliance obligations have also increased the costs of oil pipeline operations. The most significant of these additional regulations are discussed below.
Public Awareness Programs

The Pipeline Operator Public Awareness Program regulation was published on May 19, 2005, and became effective on June 20, 2005. Each pipeline operator was required to develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute’s (API) Recommended Practice (RP) 1162, while assessing the unique attributes and characteristics of the operator’s pipeline and facilities. The RP contains extensive guidance on elements of a baseline program and supplemental enhancements to be taken in various situations. Operators were required to have their plans in place by June 20, 2005.

Implementation of this regulation requires that pipeline operators routinely communicate with a wide variety of “stakeholders” along their pipelines, including members of the public, government officials, and emergency responders, using a variety of communications methods. One outreach tool is the distribution of millions of pipeline safety brochures to stakeholders within the proximity of a pipeline. Pipeline operators depend on outside bulk-mail operators to identify the addresses in proximity to their pipelines and to print and mail these safety brochures. All of this adds to the pipeline operator’s outside services costs.

The rule also requires that pipeline operators measure the effectiveness of these communications, although there is still uncertainty and disagreement as to how this requirement is to be implemented. The Pipeline Safety Trust, a pipeline safety advocacy organization, has raised this issue to Congress as part of the Pipeline Safety Act reauthorization, asking that Congress “make public awareness programs more meaningful and measurable.” Although the industry is continuing to assess what additional expenditures would be required to satisfy these requests, in my view the costs could be significant.

Operator Qualification Programs

The Operator Qualification (OQ) rule was published on August 27, 1999, requiring that all individuals performing “covered tasks” on a pipeline system must be “qualified” to perform those tasks by October 28, 2002. Based on my experience in the industry, the vast majority of oil pipeline personnel are highly qualified and were highly qualified prior to the adoption of the regulations. The regulations, however, imposed specific requirements for documenting and assessing the qualifications of pipeline personnel. First, pipeline operators were required to identify all of the “covered tasks” that are performed on their pipeline systems and then to develop specific qualification requirements and evaluation methods for each of those tasks. Almost all operators identified more than 50 different “covered tasks” that their employees or

17 See 49 CFR § 192.616 (Published in 70 Fed. Reg. 35041 (June 16, 2005)).
contractors perform. Operators then evaluated the tasks and documented each individual’s qualifications for every task that they perform. Many employees are required to have multiple task qualifications. These qualifications are not for life and must be renewed on a regular basis. Even a small pipeline company with 100 employees and contractors could easily have thousands of qualifications to maintain, track, and renew on a perpetual basis.

After the OQ rule was promulgated and implemented by pipeline operators, regulators determined that the rule should be implemented more strictly than the regulation would seem to require. This led to what the industry refers to as “OQ2,” implemented through PHMSA's publication of FAQs and a much more extensive audit protocol. In a series of meetings in early 2003, industry raised 13 OQ implementation issues with PHMSA. The audit protocols were amended to incorporate some, but not all, of these concerns. An industry standard, known as ASME B31Q, was initiated to provide additional guidance on these topics. Meanwhile, Congress required, as part of the Pipeline Safety Improvement Act of 2002, that PHMSA complete its initial inspections of pipeline operators by December 17, 2005.20

Even experienced operators are required to renew every qualification that they maintain on a perpetual basis. As employees become more experienced in more areas, they obtain ever more qualifications that must be tracked and renewed. For these reasons, the OQ rule continues to require significant expenditures of time, money, and resources by all pipeline operators in order to ensure compliance.

IV. New and Anticipated Regulatory Actions

The key regulatory mandates discussed above will continue to require pipelines to make significant expenditures for the foreseeable future. Other regulatory changes that have recently been implemented or which are pending, or likely to be adopted, will further increase pipeline operators’ costs in future years. Below, I briefly describe certain new and anticipated regulatory requirements applicable to liquid pipelines.

Control Room Management

Most regulated liquid pipeline mileage is monitored and controlled via personnel in a remote “control room.” These are similar to the flight control rooms that air traffic controllers use to monitor and direct airline traffic. On December 3, 2009, PHMSA published a new regulation entitled “Pipeline Safety: Control Room Management / Human Factors.” This rule became effective on February 1, 2010.21 Affected operators are required to develop control room management procedures by August 1, 2011, and to implement those procedures by February 1, 2013. According to the rule preamble:

Under the final rule, affected pipeline operators must define the roles and responsibilities of controllers and provide controllers with the necessary

20 Id.
information, training, and processes to fulfill these responsibilities. Operators must also implement methods to prevent controller fatigue. The final rule further requires operators to manage SCADA alarms, assure control room considerations are taken into account when changing pipeline equipment or configurations, and review reportable incidents or accidents to determine whether control room actions contributed to the event.

At this point there is still uncertainty concerning the full scope and impact of this regulation. Nevertheless, under the regulation as written, each operator must evaluate its existing systems and procedures, and modify them as appropriate. The rule requires that SCADA displays be verified when field equipment monitored by SCADA is moved or when other changes that affect pipeline safety are made to field equipment or displays. It also requires a monthly review of alarms received by the control room and an annual review of the alarm management plan. Operators must also meet certain additional standards with respect to displays that are added, expanded or replaced after implementation of the new control room management procedures.

PHMSA’s Regulatory Impact Analysis for this rule estimates first year costs for the liquid pipeline industry of between $11.1 million and $17.6 million, and annual recurring costs of $6.5 million to $10.2 million. PHMSA, however, also states that “[t]here is a high degree of uncertainty in the estimates of both the costs and benefits of the rule.” 22 Pipeline operators generally believe that these PHMSA cost estimates are too low, and, in my view, the actual costs of implementation will likely be significantly higher than the PHMSA estimates.

Greenhouse Gas Reporting and Reduction

Greenhouse gasses (GHG) include CO2, methane and other volatile organic compounds. The Environmental Protection Agency (EPA) issued its Final Rule on Mandatory Reporting of Greenhouse Gases, effective December 29, 2009, requiring the reporting of GHGs from all types of industrial activities. 23 A proposed supplemental rulemaking was issued April 12, 2010 24 and a final rule is expected in October, 2010. The supplemental rulemaking addresses reporting of greenhouse gas emissions from the petroleum and natural gas industry, including industry segments which have significant fugitive and vented emissions of carbon dioxide and methane. The supplemental rulemaking proposes reporting requirements that would apply to facilities in specific segments of the petroleum and natural gas industry that emit GHG’s greater than or equal to 25,000 metric tons of CO2 equivalent per year. It is unclear what steps liquid pipelines might need to take under this or future GHG control regulations, although the costs could be significant if the reporting threshold is reduced and the EPA chooses, or is required, to regulate emissions of GHG at lower levels than currently envisioned.

22 Id.
**PIPA Implementation**

In 2008, PHMSA launched the Pipelines and Informed Planning Alliance (PIPA) to develop risk-informed land use guidance for activities on and near pipeline rights-of-way (ROW). The final PIPA report is awaiting publication. It is anticipated that these guidelines will be widely accepted and implemented by various parties, including community planners, property owners and developers, and pipeline operators in communities throughout the country. Some communities (indeed, some entire states) may incorporate these voluntary guidelines into their land use regulations. Depending on how this is implemented, it could have significant cost implications for pipeline operations and maintenance, including relocations and new construction.

**Chemical Facility Anti-Terrorism Standards**

Hazardous liquid pipelines have also been impacted by the Chemical Facility Anti-Terrorism Standards (CFATS), which became effective on June 8, 2007. Initially, CFATS did not appear to affect many pipeline operators, but a chemicals list rule issued on November 20, 2007, included gasoline storage as a regulated facility. In the initial rule publication, the Department of Homeland Security (“DHS”) stated that: “DHS fully understands that, in addition to capital costs, facilities may also incur noncapital costs, including the costs of additional personnel (e.g., security guards) and the costs of preparing assessments and plans.”\(^{25}\) Regulated facilities are currently required to submit a detailed questionnaire, develop a vulnerability assessment, and ultimately develop and implement a site security plan based upon factors that DHS has developed but has not made available to owners and operators of the facilities. It is impossible at this stage to estimate the costs to comply with these requirements in future years; however, in my opinion, the cost of compliance for oil pipelines could be substantial.

**Conclusions**

Liquid pipelines transport billions of barrels of crude oil and refined petroleum products safely and efficiently each year. To provide transportation services safely and efficiently, and to comply with substantial and growing Federal and state government regulatory requirements, pipelines incur significant costs. In my opinion, the increase in oil pipeline costs calculated by Dr. Shehadeh for the 2004 through 2009 period is consistent with the regulatory obligations and cost pressures faced by oil pipeline operators during that period. In my view, these regulatory trends and the corresponding cost increases will likely continue for the foreseeable future. The index established to cap oil pipeline rates must take into account these realities, especially if the goals of federal safety and integrity regulations are to be fully realized.

Regulatory requirements related to pipeline integrity have caused pipeline operators to expend large sums to assess the condition of their pipelines and take additional steps to reduce the threats to pipeline integrity and remediate any defects found. These expenditures will continue for the

foreseeable future and are likely to grow. Additional existing regulations have also caused operators to incur significant costs during recent years. The expenditures related to compliance with these and other new and anticipated regulations are likely to cause pipeline costs to continue to increase in future years.

**Declaration**

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed this 19th day of August, 2010

William R. Byrd, PE
Attachments

W. R. Byrd, CV
W.R. (Bill) Byrd, P.E.
President, RCP Inc.

Executive Summary
As founder and principal of RCP, Mr. Byrd enjoys a solid reputation for working with the public, corporate executives, legal representatives, and regulatory agencies to resolve complex regulatory, integrity management, safety, and compliance management issues. He combines exceptional analytical and communication skills with a broad background in engineering, operations, management, economics, and regulatory affairs, yielding excellent professional judgment and problem-solving capabilities that can be applied to corporate-level issues. He is a widely respected public speaker, and is routinely called upon to make presentations to industry associations and other groups at the national level.

Accomplishments/Experience
Mr. Byrd’s accomplishments and experience include:

- Founding and directing the growth of RCP Inc, a professional engineering and regulatory consulting firm serving more than 100 energy firms in the US and overseas.
- Serving as the consulting expert to the API / AOPL Pipeline Performance Excellence Team, a permanent team composed of pipeline executives dedicated to improving the safety of the liquid transmission pipeline industry.
- Serving on the INGAA Foundation with other pipeline company and contractor executives to identify, prioritize, and fund research projects for the gas transmission industry.
- Serving as a consulting expert during the first criminal prosecution under the Pipeline Safety Act.
- Serving as an expert witness during the first class action lawsuit brought against a pipeline company under the citizen suit provisions of the Pipeline Safety Act.
- Serving as an expert witness / consulting expert on several other pipeline accidents and lawsuits, including those of national significance.
- Chairing the Offshore Corrosion Surveillance Subcommittee for a major pipeline company.
- Leading the development and implementation of a corrosion control strategy for oil and gas operations on the North Slope of Alaska in response to congressional investigations.
- Leading the development of a multi-skill progression program for a major pipeline company with a unionized workforce.
- Developing a new approach for H2S contingency planning in large sour oil and gas production areas, and co-authored two papers based on that work at the first annual EPA/SPE Joint Exploration and Production Environmental Conference.
- Developing solutions for produced water toxicity issues on the Outer Continental Shelf, NORM sampling and testing procedures for oil field wastes, and asbestos exposure issues.
Associations/Affiliations

- American Gas Association
- American Petroleum Institute
- American Society of Mechanical Engineers
  - Member of the Executive Committee of the Safety Engineering and Risk Analysis Division (SERAD)
  - Chair of the Safety Engineering, Risk Analysis and Reliability Methods track at the 2010 ASME International Mechanical Engineering Congress & Exposition
- American Society of Safety Engineers
- Brazil – Texas Chamber of Commerce
- CATO Benefactor
- Houston Pipeliners Association
- Interstate Natural Gas Association of America Foundation
- National Association of Corrosion Engineers
- Offshore Operators Committee
- Southern Gas Association
- Texas Gas Association
- The Auditing Roundtable

Education

M.S., Mechanical Engineering – Honors, Georgia Institute of Technology, 1982
B.S., Mechanical Engineering – Summa Cum Laude, Georgia Institute of Technology, 1981

Professional Registrations

- Professional Engineer, State of Texas
- Professional Engineer, State of Louisiana
- Professional Engineer, State of Mississippi
- Professional Engineer, State of Alabama
- Professional Member - American Society of Safety Engineers
- Professional Member – National Association of Corrosion Engineers

Honors and Awards

- Fellow-Georgia Power Research Laboratory
- Pi Tau Sigma
- Tau Beta Pi
- Gamma Beta Phi
- Phi Kappa Phi
- Certificate of Appreciation - U. S. Coast Guard
- Commendation for presentation to members of the Russian Duma
- Commendation from Air Liquide for expert litigation support
Publications/Presentations
(excluding in-house training sessions)

W. R. Byrd; DOT Existing Regulations for Leak Detection; Presented at the Siemens Technology Conference, Houston, TX, February 23, 2010

W. R. Byrd; New Control Room Management Regulations Require Structured Management Approach; Pipeline & Gas Journal, February, 2010

W. R. Byrd; Offshore Pipeline Construction and Operation; Presented to the Select Policy Council on Strategic & Economic Planning of the Florida House of Representatives, Tallahassee, FL, February 4, 2010

W. R. Byrd; API, AOPL Working to Standardize GPS System; Oil & Gas Journal, November 9, 2009

W. R. Byrd, Methods for Complying with Pipeline Leak Detection and Monitoring Regulations; Presented at the Pipeline Leak Detection & Monitoring Conference, Houston, Texas, October 28, 2009

W. R. Byrd; Pipeline Integrity Management Rules Affecting Gathering, Transmission, and Distribution Pipelines; GITA Oil & Gas Conference, End to End: Risk and Integrity Management seminar, Houston, TX, September 14, 2009

W. R. Byrd; New and Proposed Pipeline Regulations 2-2009; Presented at the OQSG User Conference, Houston, Texas, February 26, 2009

W. R. Byrd, Ken Palmer, Jack Garrett; One-call System Addresses Offshore Damage Prevention; Oil & Gas Journal, May 4, 2009

W. R. Byrd, Best Practices in Damage Prevention for Parallel Construction Projects; Presented at the API Pipeline Conference, Fort Worth, Texas, April 21, 2009

W. R. Byrd, Ken Palmer; Company Name Change Requires Diligent Execution; Oil & Gas Journal, March 16, 2009

W. R. Byrd; Overview of Shale-Gas Pipeline Development Activities; Presented at the Barnett Shale Expo, Fort Worth, Texas, March 11, 2009

W. R. Byrd; Overview of Shale-Gas Pipeline Development Activities; Presented at the Haynesville Shale Expo, Shreveport, Louisiana, November 21, 2008

W. R. Byrd; Best Practices in Damage Prevention for Parallel Construction Projects; Presented at the 7th International Pipeline Conference, Calgary, Alberta, Canada, October 1, 2008
Publications/Presentations (continued)

W. R. Byrd; Risk Factors for Urban Shale Gas Pipeline Development; Presentation to Mayor’s Shale Gas Development Task Force, Fort Worth, Texas, August 7, 2008

W. R. Byrd; Damage Prevention Workshop Findings and Recommendations; Presented at the API Pipeline Conference, Orlando, FL, April 8, 2008

W. R. Byrd; Management Systems and Safety Culture Survey Findings and Recommendations; Presented at the Liquid Pipeline Leadership meeting, Squaw Valley, CA, June 25, 2007

W. R. Byrd; Risk Management and Integrity Regulations for Gas and Liquid Pipelines; GITA Oil & Gas Conference, Houston, TX, September 18, 2006

W. R. Byrd; Overview of the new Gas Gathering Regulations; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, May 10, 2006

W. R. Byrd; Introduction to DOT Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, February 22, 2006

W. R. Byrd; Regulatory Developments for Pipeline Integrity Management; Presentation at the Geospatial Information Technology Association’s 14th Annual GIS for Oil & Gas Conference, JW Marriott Hotel • Houston, Texas; September 19, 2005

W. R. Byrd; Introduction to DOT Pipeline Regulations; Texas State Pipeline Regulations; Louisiana State Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, February 22 – 24, 2005

W. R. Byrd, R. G. McCoy, D. Wint; A Success Guide for Pipeline Integrity Management; Pipeline Gas & Journal, November 2004


W. R. Byrd; Associated Regulatory Compliance Issues for Integrity Management; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, September 22, 2004

W. R. Byrd; Introduction to DOT Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, April 6, 2004

Publications/Presentations (continued)

W. R. Byrd; Introduction to DOT Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, Houston, TX, July 30-31, 2003

W. R. Byrd; Learnings from the Olympic Pipeline Incident; in-house training for Portland Pipeline, Portland, ME, April 2, 2003

W. R. Byrd; DOT Pipeline Regulatory Developments; Presented at the US Oil and Gas Association Conference, Jackson, MS, October 30, 2002

W. R. Byrd; DOT Pipeline Training Regulations; Presented at the API Training and Development Conference, Galveston, TX, October 25, 2002

W. R. Byrd; Introduction to DOT Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, March 21-22, 2002

W. R. Byrd; State Pipeline Regulatory Initiatives; Presented at the US Oil and Gas Association annual meeting, Jackson, MS; October 10, 2001.

W. R. Byrd; State Pipeline Regulatory Initiatives; Presented at the Southwest Gas Association annual meeting, Phoenix, AZ; August 29, 2001.

W. R. Byrd; OPA 90 Planning Requirements for US Coast Guard Regulated Facilities; Presented at the US Coast Guard compliance workshop; New Orleans, LA, August 16, 2001.

W. R. Byrd; Operator Qualification Program Requirements / Overview; Presented at the Greater Baton Rouge Industrial Managers Association, March 28, 2001; and the Lake Area Industry Alliance, May 8, 2001

W. R. Byrd; Pipeline Integrity Management Program Development / Risk Analysis; Presented at the Pipeline Integrity Management Workshop, March 6-8, 2001

W. R. Byrd; Operator Qualification - Program Management Issues; Presented at the DOT Pipeline Operator Qualification Workshop, November 14-15, 2000

W. R. Byrd; Operator Qualification Issues and Industry Resources; Presented at the DOT Pipeline Compliance Workshop, May 18, 2000

W. R. Byrd; New and Proposed Rule Changes for DOT Pipelines; Presented at the DOT Pipeline Compliance Workshop, May 17, 2000

W. R. Byrd; Introduction to DOT Pipeline Regulations; Presented at the DOT Pipeline Compliance Workshop, May 16, 2000
Publications/Presentations (continued)

W. R. Byrd; Electronic Contingency Plan Team Status, Findings, and Path Forward; Presented at the EPA / USCG Region VI Response Team meeting, January 19, 2000

W. R. Byrd; Pipeline Legal / Regulatory Requirements for Community Relations; Presented at the 1999 API Pipeline Conference, April 21, 1999

W. R. Byrd, S. H. Kasper; Proposed USCG Hazmat Spill Planning Rule; Presented at the ILTA Southern Region Spring Meeting, April 27, 1999

W. R. Byrd; DOT Inspections - Current Expectations; Presented at the DOT Pipeline Compliance Workshops, September, 1998

W. R. Byrd; Plan Integration Subcommittee: Objectives and Plans; Presented at the New Orleans Area Committee Meeting, July 30, 1998

W. R. Byrd; Relief Settings and Maintenance Activities; Presented at the Coast Guard Compliance Workshops, May, 1998

W.R. Byrd; ...And Now a Word from Washington; Presented at the Louisiana Pipeliners Association Meeting, September 9, 1997.


Publications/Presentations (continued)


W.R. Byrd, R.A. Brunell; New Developments in USCG Regulations for Dock Facilities; presented at RCP’s U.S. Coast Guard Regulatory Seminar, August 8, 1996.


W.R. Byrd, Pipeline Risk Management Programs; June 20-21, 1996.
